MIRANT CORP
Form 10-K
March 01, 2007

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, 2006

Or

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

For the Transition Period from to

Mirant Corporation

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of Incorporation or Organization)	**001 16107** (Commission File Number)	**58 2056305** (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 whether the registrant is a well-known seasoned issuer (as defined by Rule 405 of the Securities Act). o Yes x No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. o 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 o 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. o

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

x Large Accelerated Filer o Accelerated Filer o Non-accelerated Filer

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

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 o No

Aggregate market value of voting stock held by non-affiliates of the registrant was approximately $8,041,023,653 on June 30, 2006 (based on $26.80 per share, the closing price in the daily composite list for transactions on the New York Stock Exchange that day). As of January 31, 2007, there were 255,974,046 shares of the registrant s Common Stock, $0.01 par value per share, outstanding.

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Glossary of Certain Defined Terms

ACO Administrative Compliance Order.

AEP American Electric Power, Inc.

APB Accounting Principles Board.

APB 18 APB Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stocks*.

APB 22 APB Opinion No. 22, *Disclosure of Accounting Policies*.

APSA Asset Purchase and Sale Agreement.

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 runs continuously.

BOT The Philippine Government s build, operate and transfer program.

CAIR Clean Air Interstate Rule.

CAISO California Independent System Operator.

Cal DWR California Department of Water Resources.

Cal PX California Power Exchange.

CAMR Clean Air Mercury Rule.

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

CFTC Commodity Futures Trading Commission.

Clean Air Act Federal Clean Air Act.

Clean Water Act Federal Water Pollution Control Act.

CO Carbon monoxide.

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.

CUC Curacao Utilities Company.

DOE United States Department of Energy.

DOJ United States Department of Justice.

DP&L Dayton Power & Light.

EBITDA Earnings before interest, taxes, depreciation and amortization.

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

EITF 04-13 EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*.

EITF 06-3 EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation).*

EOB California Electricity Oversight Board.

EPA United States Environmental Protection Agency.

EPAct 2005 Energy Policy Act of 2005.

EPS Earnings per Share.

ERCOT Electric Reliability Council of Texas.

ERISA Employee Retirement Income Security Act of 1974.

FASB Financial Accounting Standards Board.

FERC Federal Energy Regulatory Commission.

FIN FASB Interpretation.

FIN 46R FIN No. 46R, *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*.

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

FSP FASB Staff Position.

FSP AUG AIR-1 FSP AUG AIR-1, *Accounting for Planned Major Maintenance Activities*.

FSP FAS 13-2 FSP FAS 13-2, *Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction*.

FSP FIN 46R-6 FASB Staff Position FASB Interpretation 46R-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R*.

GAAP Generally accepted accounting principles in the United States.

Grand Bahama Power Grand Bahama Power Company.

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

Hudson Valley Gas Hudson Valley Gas Corporation.

IBEW International Brotherhood of Electrical Workers.

ICE 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.

JEP Jamaica Energy Partners.

JPPC Jamaica Private Power Company Limited.

JPS Jamaica Public Service Company Limited.

LIBOR London InterBank Offered Rate.

LICAP Locational installed capacity plan.

LTSA Long term service agreement.

Massachusetts DEP Massachusetts Department of Environmental Protection.

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.

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 JPS Finance Mirant JPSCO Finance LTD.

Mirant Lovett Mirant Lovett, LLC.

Mirant Mid-Atlantic Mirant Mid-Atlantic, LLC.

Mirant New York Mirant New York, Inc.

Mirant North America Mirant North America, LLC.

Mirant NY-Gen Mirant NY-Gen, LLC.

Mirant Pagbilao Mirant Pagbilao Corporation.

Mirant Peaker Mirant Peaker, LLC.

Mirant Potomac River Mirant Potomac River, LLC.

Mirant Power Purchase Mirant Power Purchase, LLC.

Mirant Sual Mirant Sual Corporation.

Mirant Sugar Creek Mirant Sugar Creek, LLC.

Mirant Trinidad Investments Mirant Trinidad Investments, LLC.

Mirant Zeeland Mirant Zeeland, LLC.

MISO Midwest Independent Transmission System Operator.

MMbtu Million British Thermal Units.

MW Megawatt.

MWh Megawatt hour.

NAAQS National ambient air quality standards.

NEPOOL New England Power Pool.

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

NO2 Nitrogen dioxide.

NOL Net operating loss.

NOV Notice of violation.

NOx Nitrogen oxides.

NPC National Power Corporation.

NSR New source review.

NSTAR NSTAR Electric and Gas Corporation.

NYISO Independent System Operator of New York.

NYSDEC New York State Department of Environmental Conservation.

NYSE New York Stock Exchange.

OCI Other comprehensive income.

Ohio Edison Ohio Edison Company.

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.

Panda Panda-Brandywine, LP.

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

Pension Protection Act Pension Protection Act of 2006.

Pepco Potomac Electric Power Company.

PG&E Pacific Gas & Electric Company.

PILOT Payments in lieu of taxes.

PJM Pennsylvania-New Jersey-Maryland Interconnection, LLC.

PM10 Particulate matter that is 10 microns or less in size.

PowerGen The Power Generation Company of Trinidad and Tobago.

PPA Power purchase agreement.

PUHCA Public Utility Holding Company Act of 1935.

PURPA Public Utility Regulatory Policies Act of 1978.

Reserve Margin Excess capacity over peak demand.

RMR Reliability-must-run.

RPM Reliability Pricing Model.

RTO Regional transmission organization.

SAB SEC Staff Accounting Bulletin.

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

SAB No. 108 SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*.

SCE Southern California Edison Company.

SEC U.S. Securities and Exchange Commission.

Securities Act The Securities Act of 1933.

SFAS Statement of Financial Accounting Standards Board.

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

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

SFAS No. 123 SFAS No. 123, *Accounting for Stock-Based Compensation*.

SFAS No. 123R SFAS No. 123R, *Share-Based Payment.*

SFAS No. 132R SFAS No. 132R, *Employers Disclosures about Pensions and Other Postretirement Benefits an amendment of FASB Statements No. 87, 88, and 106.*

SFAS No. 133 SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*.

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

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

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

SFAS No. 153 *SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29.*

SFAS No. 155 SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*.

SFAS No. 156 SFAS No. 156, *Accounting for Servicing of Financial Assets an amendment of FASB Statement No. 140*.

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

SFAS No. 158 SFAS No. 158, *Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans: an amendment of FASB Statements No. 87, 88, 106, and 132R.*

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

Shady Hills Shady Hills Power Company, L.L.C.

SO2 Sulfur dioxide.

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

T&TEC Trinidad and Tobago Electricity Commission.

The Tokyo Electric Power Company The Tokyo Electric Power Company, Incorporated.

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TPA Transition power agreement.

UWUA Utility Workers Union of America.

VaR Value-at-risk.

VIE Variable interest entity.

Virginia DEQ Virginia Department of Environmental Quality.

West Georgia West Georgia Generating Company, L.L.C.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING 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, in addition to historical information. 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, plan, anticipate, estimate, predict, t 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; changes in state, federal and other regulations (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 assets to perform as expected, including outages for unscheduled maintenance or repair, and the timely completion of the repairs on the Sual generating facility;

- our ability to divest our Caribbean business at a price and on terms that we would be willing to accept, and our ability to consummate the sale of our Philippine business and the sale of six of our U.S. intermediate and peaking natural gas-fired plants, as well as any adverse impact on our credit ratings that may result from such sales;

- changes in market conditions, including developments in the supply, demand, volume and pricing of electricity and other commodities in the energy markets, or the extent and timing of the entry of additional competition in our markets or those of our subsidiaries and affiliates;

- increased margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts which are expected;

- our inability to access effectively the over-the-counter and exchange-based commodity markets or changes in commodity market liquidity or other commodity market conditions, which may affect our ability to engage in asset management and proprietary trading activities as expected, or result in material extraordinary gains or losses from open positions in fuel oil or other commodities;

- deterioration in the financial condition of our counterparties and the resulting failure 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 generation units adequately for all of their costs;

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

- our inability to enter into intermediate and long-term contracts to sell power and procure fuel, including its transportation, on terms and prices acceptable to us;

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- legislative and regulatory initiatives and changes in the application of laws and regulations by national and local governments, including increases in tax rates or assessments, in non-U.S. jurisdictions in which our subsidiaries operate;
- factors that affect the operations of our international subsidiaries, such as political instability, local security concerns, tax increases, expropriation of property, cancellation of contract rights and environmental regulations;
- 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;
- our ability to obtain adequate supply and delivery of fuel for our facilities;
- curtailment of operations due to transmission constraints;
- environmental regulations that restrict our ability or render it uneconomic to operate our business, including regulations related to the emission of carbon dioxide 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;
- war, terrorist activities or the occurrence of a catastrophic loss;
- the fact that our New York subsidiaries remain in bankruptcy;
- our substantial 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 and Mirant Asia-Pacific Limited contained in their financing agreements and restrictions on Mirant Mid-Atlantic contained in its leveraged lease documents, which may affect our ability to access the cash flow of those subsidiaries to make debt service and other payments;
- the resolution of claims and obligations that were not resolved during the Chapter 11 process that may have a material adverse effect on our results of operations; and
- the disposition of the pending litigation described in this Form 10-K.

Many of these risks 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.

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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 under 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 o after January 3, 2006, as further discussed in Item 1. Business.

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PART I

Item 1. ***Business***

Overview

We generate revenue primarily through the production of electricity in the United States, the Philippines and the Caribbean. As of December 31, 2006, we owned or leased 17,522 MW of electric generating capacity. Mirant Corporation was incorporated in Delaware on September 23, 2005, and is the successor to a corporation of the same name that was formed in Delaware on April 3, 1993. This succession occurred by virtue of the transfer of substantially all of Old Mirant s assets to New Mirant in conjunction with Mirant s emergence from bankruptcy protection on January 3, 2006. Old Mirant was then renamed and transferred to a trust, which is not affiliated with new Mirant. New Mirant serves as the corporate parent of the business enterprise and, pursuant to the Plan of Reorganization (the Plan) that was approved in connection with old Mirant s emergence from bankruptcy, has no successor liability for any unassumed obligations of old Mirant.

In the third quarter of 2006, we commenced separate auction processes to sell our Philippine (2,203 MW) and Caribbean (1,050 MW) businesses and certain of our U.S. natural gas-fired assets totaling 3,619 MW, including our Zeeland (903 MW), West Georgia (613 MW), Shady Hills (469 MW), Sugar Creek (561 MW), Bosque (546 MW) and Apex (527 MW) facilities. See Note 3 to our consolidated financial statements for additional information regarding the treatment of these businesses and assets as discontinued operations as a result of these decisions.

On December 11, 2006, we entered into a definitive purchase and sale agreement with a consortium of The Tokyo Electric Power Company and Marubeni Corporation for the sale of our Philippine business for a purchase price of $3.424 billion, plus a working capital adjustment at the closing. After the payment of related debt, which is estimated to be $642 million at the closing, the net proceeds to Mirant are expected to be $3.121 billion after transaction costs. The transaction is expected to close in the second quarter of 2007 after the satisfaction of certain customary conditions and the return to operation of both units of the Sual plant.

On January 15, 2007, we entered into a definitive purchase and sale agreement with a subsidiary of LS Power Equity Partners I, L.P., LS Power Equity Partners II, L.P. and certain other affiliated funds, (collectively, LS Power), for the sale of six U.S. natural gas-fired plants for a purchase price of $1.407 billion, which includes estimated working capital and certain surplus generating equipment. After the payment of $83 million of related debt, the net proceeds are expected to be $1.307 billion after transaction costs. The transaction is expected to close in the second quarter of 2007 after the satisfaction of certain customary conditions.

The auction and due diligence processes in respect of the sale of the Caribbean business are under way and the sale of the Caribbean business is expected to close by mid-2007.

After giving effect to the aforementioned sales, our continuing operations of 10,650 MW will consist of the ownership, long-term lease and operation of power generation facilities located in the Mid-Atlantic and Northeast regions of the United States and in California, and energy trading and marketing operations in Atlanta.

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 be found at www.mirant.com. We will provide print copies of these documents to any shareholder upon written request to Corporate Secretary, Mirant Corporation, 1155 Perimeter Center West, Atlanta, Georgia 30338-5416. Information contained in our website is not incorporated into this Form 10-K.

U.S. Competitive Environment

Historically, vertically integrated electric utilities with monopolistic control over franchised territories dominated the power generation industry in the United States. The enactment of the PURPA, and the subsequent passage of the Energy Policy Act of 1992, fostered the growth of independent power producers. During the 1990s, a series of regulatory policies were partially implemented at both the federal and state levels to encourage competition in wholesale electricity markets.

As a result, independent power producers built new generating plants, purchased plants from regulated utilities and marketed wholesale power. ISOs and RTOs were created to administer the new markets and maintain system reliability. Beginning in 2001, however, in response to extreme price volatility and electricity shortages in California, regulators began to re-examine the nature and pace of deregulation of wholesale electricity markets, and that re-examination is continuing.

Independent power producers, as well as utilities, constructed primarily natural gas-fired plants in the 1990s because natural gas prices were low and such plants could be constructed more quickly and were less expensive to permit and build than nuclear and coal-fired plants. Stagnation in the growth of natural gas supplies, the increased demand from new generation facilities and the damage caused by hurricanes Katrina and Rita resulted in a sharp increase in the price of natural gas during 2005. In 2006, there was volatility in natural gas prices, with a substantial decline from their 2005 highs. Although natural gas prices have declined from 2005, natural gas prices remain high compared to historical prices. High natural gas prices have contributed to high electricity prices.

A number of factors combined to create excess generating capacity in certain U.S. markets, including a substantial increase in construction of generation facilities following the deregulation efforts described above, capital investments by utilities aimed at extending the lives of older units and the inability to decommission certain plants for reliability reasons. In certain markets in the United States, that excess has been absorbed or is close to being absorbed. Electricity demand has been growing and supply has not appreciably increased. Given the substantial time necessary to permit and construct new power plants, we think that the markets in the United States in which we operate need to begin the process now of adding generating capacity to meet growing demand. A number of key ISOs have implemented capacity markets as a way to encourage such construction of additional generation, but it is not clear whether independent power producers will be sufficiently incentivized to build this new generation.

Falling reserve margins, as well as high electricity prices as a result of high natural gas prices, have led to renewed interest in new coal-fired or nuclear plants. Coal-fired generation and nuclear generation currently account for approximately 50% and 20%, respectively, of the electricity produced in the United States. There is substantial environmental opposition to building either coal-fired or nuclear plants.

In light of the foregoing market conditions, some regulated utilities are proposing to construct coal-fired units or nuclear plants, in some cases with governmental subsidies or under legislative mandate. Unlike independent power producers like us, these utilities often are able to recover fixed costs through regulated retail rates, allowing them to build without relying on market prices to recover their investments.

Many regulated utilities are also seeking to acquire distressed assets or make substantial environmental improvements to existing coal plants, in each case with regulatory assurance that the utility will be permitted to recover its costs, plus earn a return on its investment. Success by utilities in those efforts may put independent power producers at a disadvantage because they rely heavily on market prices rather than regulatory assurances.

Business Segments

Previously, we managed our business as three operating segments: United States, Philippines and Caribbean. In 2006, we commenced separate auction processes to dispose of our Caribbean and Philippine businesses and certain U.S. natural gas-fired assets. The planned sales have resulted in the reclassification of the revenues and expenses of these businesses and assets to discontinued operations and the reclassification of the related assets and liabilities to held for sale for all periods presented. In the fourth quarter of 2006, we re-evaluated the business segments of our continuing operations. As a result, we now have four operating segments: Mid-Atlantic, Northeast, California and Other Operations. Other Operations includes proprietary trading and fuel oil management activities and gains and losses related to a contractual arrangement entered into with Pepco with respect to certain PPAs, including Pepco s long-term PPAs with Panda and Ohio Edison (the Back-to-Back Agreement). For selected financial information about our business segments, see Note 20 to our consolidated financial statements contained elsewhere in this report. See Item 2. Properties for a complete list of our assets. We have restated corresponding items of segment information for prior periods to conform with our current operating segments.

The table below summarizes selected financial information for our business segments, after giving effect to the pending sales, for the year ended December 31, 2006 (dollars in millions):

	Revenues	%	Gross Margin	%	Operating Income	%
Business Segment:						
Mid-Atlantic	$ 1,901	61 %	$ 1,318	68 %	$ 918	81 %
Northeast	827	27 %	358	18 %	128	11 %
California	171	6 %	115	6 %	39	4 %
Other Operations	204	6 %	118	6 %	52	5 %
Eliminations		%	38	2 %	(6)	(1)%
Total Continuing Operations	$ 3,103	100 %	$ 1,947	100 %	$ 1,131	100 %

Overview

Our core business is the production and sale of electrical energy, electrical capacity (the ability to produce electricity on demand) and ancillary services (services that are ancillary to transmission services). Our customers are ISOs, utilities, municipal systems, aggregators, electric cooperative utilities, producers, generators, marketers and large industrial customers.

Ownership and Operation of Electricity Generation Assets

As of December 31, 2006, our continuing operations consist of owned or leased generation facilities with 10,650 MW of generating capacity. 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 generation capacity includes approximately 32% baseload units, 48% intermediate units and 20% peaking units.

Commercial Operations

Our commercial operations consist primarily of procuring fuel, dispatching electricity, hedging the production and sale of electricity by our generating facilities, fuel oil management and providing logistical support for the operation of our facilities (for example, by procuring transportation for coal). We often sell the electricity we produce into the wholesale market at prices in effect at the time we produce it (spot price). Those prices are volatile, however, 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 into the wholesale market and purchases of fuel and emissions allowances to allow us to produce and sell the electricity for different periods of time. We procure these hedges in OTC transactions or 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. 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 that we do not produce and some fuel and emissions allowances that we do not need to produce electricity (proprietary trading). Proprietary trading is a small part of our commercial operations, which we do in order to gain information about the markets to support our asset management and to take advantage of selected opportunities that we may identify from time to time. All of our commercial activities are governed by a comprehensive Risk Management Policy, which requires that our hedging activities with respect to our assets be risk-reducing and sets limits on the size of trading positions and VaR in our proprietary trading activities.

We use dispatch models to make 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 generation facilities into the day-ahead energy market and sell ancillary services through the ISO markets. We work with the ISOs and RTOs in real time to ensure that our generation facilities are dispatched economically to meet the reliability needs of the market.

We economically hedge a substantial portion of our Mid-Atlantic coal-fired baseload generation and certain of our Northeast coal, gas and oil-fired generation through OTC transactions. However, we generally do not hedge most of our intermediate and peaking units. In 2006 and thus far in 2007, our Mirant Mid-Atlantic subsidiary entered into financial swap transactions resulting in Mirant Mid-Atlantic being economically hedged for approximately 92%, 93%, 97% and 38% of its expected on-peak coal-fired baseload generation in 2007, 2008, 2009 and 2010, respectively. The financial swap transactions include new hedges in addition to the previously disclosed January 2006 hedges. These transactions are senior unsecured obligations of Mirant Mid-Atlantic and do not require the posting of cash collateral either for initial margin or for securing exposure due to changes in power prices. As of February 26, 2007, our total portfolio is economically hedged approximately 83%, 47%, 35% and 14% for 2007, 2008, 2009 and 2010, respectively. The corresponding fuel hedges are approximately 81%, 27%, 15% and 0% for 2007, 2008, 2009 and 2010 respectively.

While OTC transactions make up a substantial portion of our economic hedge portfolio, Mirant Energy Trading also sells non-standard, structured products to customers. In addition to energy, these products typically include capacity, ancillary services and other energy products. We view these transactions as a method of mitigating the risk of certain portions of our business that are not easy to economically hedge in the OTC market. Typically, we are able to sell these products at a higher premium than standard products. Additionally, we have facilities operating under long-term contracted capacity and RMR contracts. At December 31, 2006, our contracted capacity pursuant to these agreements was 2,347 MW with terms expiring through October 2011.

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 generation facilities, we purchase coal from a variety of suppliers under contracts with terms of varying lengths, some of which extend to 2009. For our oil-fired units, fuel typically is purchased under short-term contracts linked to a transparent oil index price. For our gas-fired units, fuel typically is purchased under short-term contracts with a variety of suppliers on a day-ahead or monthly basis.

Our coal supply primarily comes from the Central Appalachian and Northern Appalachian coal regions. All of our coal is delivered by rail, although we are in the process of permitting a barge unloading facility at our Morgantown station that will enable us to receive coal by an alternative transportation source beginning in 2008. We monitor coal supply and delivery logistics carefully, and, despite occasional interruptions of scheduled deliveries, to date we have managed to avoid any significant impact to our operations. We maintain an inventory of coal at our coal-fired facilities for this purpose. Interruptions of scheduled deliveries can occur because of supply disruptions due to strikes or other reasons or as a result of rail system disruptions due to weather or other reasons.

Mid-Atlantic Region

We own or lease four generation facilities in the Mid-Atlantic region with a total generation capacity of 5,256 MW: Chalk Point, Morgantown, Dickerson and Potomac River. Our Mid-Atlantic region had a combined 2006 capacity factor (average percentage of full capacity used over a year) of 36%. Our Mid-Atlantic facilities are located in Maryland and Virginia and were acquired from Pepco in December 2000. The Chalk Point facility is our largest generation facility in the region. It consists of two coal-fired baseload units, two oil and gas-fired intermediate units and two oil-fired and five gas and oil-fired peaking units, for a total generation capacity of 2,429 MW. Our next largest facility in the region is the Morgantown facility. It consists of two dual-fueled (coal and oil) baseload units and six oil-fired peaking units, for a total generation capacity of 1,492 MW. The Dickerson facility has three coal-fired baseload units, and one oil-fired and two gas and oil-fired peaking units, for a total generation capacity of 853 MW. The Potomac River station has three coal-fired baseload units and two coal-fired intermediate units, for a total generation capacity of 482 MW.

Power generated by our Mid-Atlantic facilities is sold into the PJM market. For a discussion of the PJM market, see Regulatory Environment below. We have participated indirectly in standard offer service auctions in Maryland and Washington, D.C. Power sales, made either directly through these auctions or indirectly through subsequent market transactions that are a result of the auction process, serve as economic hedges for the Mid-Atlantic assets.

On August 24, 2005, power production at all five units of the Potomac River generating facility was temporarily halted in response to a letter from the Virginia DEQ. On August 25, 2005, the District of Columbia Public Service Commission filed an emergency petition and complaint with the FERC and the DOE to prevent the shutdown of the Potomac River facility. The matter remains pending before the FERC and the DOE. On December 20, 2005, due to a determination by the DOE that an emergency situation existed with respect to the reliability of the supply of electricity to central Washington, D.C., the DOE ordered Mirant Potomac River to generate electricity at the Potomac River generating facility, as requested by PJM, during any period in which one or both of the transmission lines serving central Washington, D.C. are out of service due to a planned or unplanned outage. In addition, the DOE ordered Mirant Potomac River, at all other times, for electric reliability purposes, to keep as many units in operation as possible and to reduce the start-up time of units not in operation without contributing to any NAAQS exceedances. The DOE required Mirant Potomac River to submit a plan that met these requirements, on or before December 30, 2005. The order further provides that Mirant Potomac River and its customers should agree to mutually satisfactory terms for any costs incurred by it under this order or just and reasonable terms shall be established by a supplemental order. Certain parties filed for rehearing of the DOE order, and on February 17, 2006, the DOE issued an order granting rehearing solely for purposes of considering further the rehearing requests. Mirant Potomac River submitted an operating plan in accordance with the order. On January 4, 2006, the DOE issued an interim response to Mirant Potomac River s operating plan authorizing operation of the units of the Potomac River generating facility on a reduced basis, but making it possible to bring the entire plant into service within approximately 28 hours when necessary for reliability purposes. The DOE s order expires July 1, 2007, but Mirant Potomac River expects it will be able to continue to operate these units after that expiration.

In a letter received December 30, 2005, the EPA invited Mirant Potomac River and the Virginia DEQ to work with the EPA to ensure that Mirant Potomac River s operating plan submitted to the DOE adequately addressed NAAQS issues. The EPA also asserted in its letter that Mirant Potomac River did not immediately undertake action as directed by the Virginia DEQ s August 19, 2005, letter and failed to comply with the requirements of the Virginia State Implementation Plan established by that letter. Mirant Potomac River received a second letter from the EPA on December 30, 2005, requiring Mirant to provide certain requested information as part of an EPA investigation to determine the Clean Air Act compliance status of the Potomac River generating facility.

On June 1, 2006, Mirant Potomac River and the EPA executed an ACO by Consent to resolve the EPA s allegations that Mirant Potomac River violated the Clean Air Act by not immediately shutting down all units at the Potomac River facility upon receipt of the Virginia DEQ s August 19, 2005, letter and to assure an acceptable level of reliability to the District of Columbia. The ACO (i) specifies certain operating scenarios and SO2 emissions limits for the Potomac River facility, which scenarios and limits take into account whether one or both of the 230kV transmission lines serving Washington, D.C. are out of service; (ii) requires the operation of trona injection units to reduce SO2 emissions; and (iii) requires Mirant Potomac River to undertake a model evaluation study to predict ambient air quality impacts from the facility s operations. In accordance with the specified operating scenarios, the ACO permits the facility to operate using a daily predictive modeling protocol. This protocol allows Mirant Potomac River to schedule the facility s level of operations based on whether computer modeling predicts a NAAQS exceedance, based on weather and certain operating parameters. On June 2, 2006, the DOE issued a letter modifying its January 6, 2006, order to direct Mirant Potomac River to comply with the ACO in order to ensure adequate electric reliability to the District of Columbia. Mirant Potomac River is operating the Potomac River facility in accordance with the ACO and has been able to operate all five units of the facility most of the time under the ACO.

Northeast Region

We own generating facilities in the Northeast region consisting of 3,047 MW of capacity. Our Northeast region had a combined 2006 capacity factor of 17%. The Northeast region is comprised of our assets located in New York and New England. The subsidiaries that own our New York facilities remain in bankruptcy. For further information, see Item 3. Legal Proceedings. Generation is sold from our Northeast facilities through a combination of bilateral contracts, spot market transactions and structured transactions.

New York. Our New York generating facilities were acquired from Orange and Rockland and Consolidated Edison Company of New York, Inc. in June 1999. The New York generating facilities consist of the Bowline and Lovett facilities and various smaller generating facilities comprising a total of 1,656 MW of capacity. The Bowline facility is a 1,125 MW dual-fueled (natural gas and oil) facility comprised of two intermediate/peaking units. The Lovett facility consists of two baseload units capable of burning coal and gas comprising a total of 348 MW and a peaking unit capable of burning gas or oil comprising 63 MW. The smaller New York generating facilities have a total capacity of 120 MW and consist of the Hillburn and Shoemaker facilities, which each contain a single peaking unit capable of running on natural gas or jet fuel, and the Mongaup 1-4, Swinging Bridge 1-2 and Rio 1-2 facilities, which each contain a hydroelectric intermediate unit. We also had an operational interest in the Grahamsville facility, pursuant to a sublease between Orange and Rockland and Mirant NY-Gen. On October 31, 2006, we transferred the Grahamsville facility to Orange and Rockland for transfer to the City of New York. The capacity, energy and ancillary services from our New York generating units are sold into the bilateral markets and into the markets administered by the NYISO through Mirant Energy Trading. For a discussion of NYISO, see Regulatory Environment below.

Our current plan is to retire units 3 and 5 at the Lovett facility by April 30, 2007, and the remaining unit by April 30, 2008, as required under the terms of a consent decree entered into on June 11, 2003, to resolve issues related to NSR regulations promulgated under the Clean Air Act (the 2003 Consent Decree) if certain environmental controls are not added to the two units of the Lovett facility that burn coal. We are also considering scenarios that allow continued operations past April 2007 and April 2008 as we continue to work with the State of New York and other parties to achieve a solution related to environmental controls and to allow Lovett to continue to contribute to the reliability of the electric system of the State of New York. In order for the facility to remain viable on a long-term basis, we need to accomplish two primary tasks. First, we need to reach agreement with the State of New York on amendments to the 2003 Consent Decree that would address the installation of environmental equipment. Second, because current market conditions do not allow Mirant Lovett to recover the necessary returns to fund the installation of environmental controls specified under the 2003 Consent Decree, we are seeking an agreement with a third party assuring us of enough revenue to justify the required capital expenditures. Our view is that the Lovett facility is necessary to the provision of reliable electricity to the Lower Hudson Valley and other areas within the New York Control Area.

In the fourth quarter of 2006, the Bankruptcy Court approved a settlement of disputed property taxes among Mirant Bowline, Mirant Lovett, Hudson Valley Gas and various New York tax jurisdictions. The settlement resolves pending disputes regarding refunds sought by us for property taxes paid for 1995 through 2003 and unpaid taxes assessed for 2003 through 2006. Under the settlement, in February 2007 we received refunds totaling approximately $163 million for 1995 through 2002, and paid unpaid taxes of approximately $115 million for 2003 through 2006, resulting in receipt of a net cash amount of $48 million. As a result of the refund and the reduction in unpaid taxes under the settlement, we recognized a gain of approximately $244 million in the fourth quarter of 2006. Of the $244 million gain recognized, $163 million is included in reorganization items, net, and $94 million is a reduction in operations and maintenance expense in the consolidated statements of operations. These amounts are partially offset by $13 million in interest expense.

In May 2005, a sinkhole was discovered in the dam of our Swinging Bridge facility. In response, Mirant NY-Gen filled this sinkhole, inspected for damage the dam s slopes and the enclosed pipe that delivers water from the reservoir to the generator, drew down the lake level and cleaned the diversion tunnel. Mirant NY-Gen s analysis indicates that the most probable cause of the sinkhole was erosion of soil comprising the dam from water flow through a hole in the pipe that delivers water from the reservoir to the generator. The dam is stabilized, and Mirant NY-Gen is performing additional remediation repairs. By letter dated June 14, 2006, the FERC authorized Mirant NY-Gen to proceed with its remediation plan for the sinkhole. The FERC has also concurred with the results of Mirant NY-Gen s flood study for its Swinging Bridge, Rio and Mongaup generation facilities, which study concluded that no additional remediation is required. On June 29, 2006, the Bankruptcy Court authorized Mirant NY-Gen to proceed with implementation of the remediation plan. The current estimated cost to remediate the dam at Swinging Bridge is approximately $29 million, of which approximately $22 million had been incurred through December 31, 2006. Mirant NY-Gen currently expects to recover insurance proceeds for a portion of these repair costs. The Bankruptcy Court has approved a debtor-in-possession loan to Mirant NY-Gen from Mirant Americas under which Mirant Americas, subject to certain conditions, would lend up to $16.5 million to Mirant NY-Gen to provide funding for the repairs on the Swinging Bridge dam.

On January 26, 2007, Mirant New York, Mirant Bowline, and Hudson Valley Gas (collectively the Emerging New York Entities) filed a Supplemental Joint Chapter 11 Plan of Reorganization of the Emerging New York Entities (the Supplemental Plan) with the Bankruptcy Court. For more detail concerning the Supplemental Plan, see Item 3. Legal Proceedings, Chapter 11 Proceedings.

On January 31, 2007, Mirant New York entered into an agreement for the sale of Mirant NY-Gen, which owns the Hillburn and Shoemaker gas turbine facilities and the Swinging Bridge, Rio and Mongaup hydroelectric generating facilities. An auction process supervised by the Bankruptcy Court is required before bankruptcy court approval may occur. The estimated sales price of $3 million is subject to adjustments for working capital and certain dam remediation efforts that are ongoing at the Swinging Bridge facility. The transaction is expected to close in the second quarter of 2007.

New England. Our New England generating facilities, with a total capacity of 1,391 MW, were acquired from subsidiaries of Commonwealth Energy System and Eastern Utilities Associates in December 1998. The New England generating facilities consist of the Canal station, the Kendall station, the Martha s Vineyard diesels and an interest in the Wyman unit 4 facility. The Canal and Kendall facilities, located in close proximity to Boston, consist of 1,112 MW and 256 MW of generating capacity, respectively, and are designed to operate during periods of intermediate and peak demand. The Kendall facility is a combined cycle facility which produces both steam and electricity for sale. Both the Canal and Kendall facilities possess the ability to burn both natural gas and fuel oil. The Martha s Vineyard diesels, with 14 MW of capacity, supply electricity on the island of Martha s Vineyard during periods of high demand or in the event of a transmission interruption. The Wyman unit 4 interest is an approximate 1.4% ownership interest (equivalent to 9 MW) in the 614 MW Wyman unit 4 located on Cousin s Island, Yarmouth, Maine. Wyman unit 4 is primarily owned and operated by the Florida Power and Light Group.

The capacity, energy and ancillary services from our New England generating units are sold into the NEPOOL bilateral markets and into the markets administered by the ISO-NE through Mirant Energy Trading. For a discussion of the NEPOOL and the ISO-NE, see Regulatory Environment below.

We had determined that market fundamentals in NEPOOL did not permit us to operate the Kendall facility on an economical basis as a merchant facility. We therefore had planned to shut down, at least temporarily, the Kendall facility from January 2005 through December 2007, with the possibility of restarting operations as early as January 2008. However, the ISO-NE determined that part of the capacity of the Kendall facility was needed for reliability and proposed an RMR agreement with a term lasting until the earlier of (1) the date a locational installed capacity cost recovery mechanism applicable to the Kendall facility is in place or (2) 120-days after we are provided written notice. We entered into and received FERC approval for an agreement with NSTAR and ISO-NE, which included the RMR agreement. On December 28, 2006, ISO-NE provided notice that the RMR agreement shall terminate effective May 1, 2007. A locational installed capacity market has been implemented in New England and, as a result and coupled with additional steam sales, there are no plans to shut down the Kendall facility in 2007.

California

Our California facilities, with a total capacity of 2,347 MW, are primarily gas-fired generating facilities and consist of the Pittsburg, Contra Costa and Potrero facilities, which have generation capacity of 1,311 MW, 674 MW and 362 MW, respectively. Our California facilities had a 2006 capacity factor of 6%.

The Pittsburg and Contra Costa facilities are natural gas facilities and both generate electricity by using gas-fired steam boilers. They are located in Contra Costa County, approximately ten miles apart along the Sacramento/San Joaquin River. The Potrero facility, located in the City of San Francisco, has one natural gas-fired intermediate steam boiler from which it generates electricity and three oil-fired peaking distillate fueled combustion turbines.

Through the end of 2006, the majority of our California assets were subject to RMR arrangements with the CAISO. These agreements are described further under Regulatory Environment below. Our California subsidiaries had the largest portfolio of units that operated under RMR arrangements in California, reflecting that the location of these units is key to electric system reliability. 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 our natural gas-fired units at Pittsburg and Contra Costa, including Pittsburg unit 7 and Contra Costa unit 6. The agreements are for 100% of the capacity from these assets, approximately 2,000 MW. The contracts have varying tenors ranging from one to four years, and include capacity of 1,985 MW for 2007, 2008 and 2009, 1,303 MW for 2010 and 674 MW for 2011. We will receive monthly capacity payments with bonuses and/or penalties based on guaranteed heat rate and availability tolerances. As a result of these contracts, the Pittsburg and Contra Costa units are no longer subject to the RMR agreements. Potrero units 3-6 continue to be subject to the RMR arrangements as described.

On January 14, 2005, we and certain of our subsidiaries entered into a Settlement and Release of Claims Agreement (the California Settlement) with PG&E, SCE, San Diego Gas and Electric Company, the CPUC, the Cal DWR, the EOB and the Attorney General of the State of California and with the Office of Market Oversight and Investigations of the FERC. Pursuant to the settlement agreement that became effective in April 2005*,* the partially constructed Contra Costa unit 8 project, which is a planned 530 MW combined cycle generating facility, and related equipment (collectively, the CC8 Assets) were transferred to PG&E on November 29, 2006. Mirant Delta received $70 million that under the terms of the settlement had been held in an escrow account to be paid to PG&E if the Contra Costa 8 project was not transferred to it by June 30, 2008. We recognized a gain of $27 million in the fourth quarter of 2006 as a result of these transfers.

Discontinued Operations

Philippines

Our subsidiaries have ownership interests in three generating facilities in the Philippines: Sual (1,218 MW/100% owned), Pagbilao (735 MW/100% owned) and Ilijan (1,251 MW/20% owned). As of December 31, 2006, our net ownership interest in the generating capacity of these facilities was 2,203 MW.

Substantially all of the generation capacity of the Sual and Pagbilao facilities is sold under long-term energy conversion agreements with the Philippine government-owned NPC. NPC acts as both the fuel supplier and the energy purchaser for the Sual and Pagbilao facilities. NPC procures all of the fuel necessary for generation at no cost to the respective operating company.

Under the energy conversion agreements, Sual and Pagbilao receive both fixed capacity fees and variable energy fees. Fixed capacity fees are paid without regard to the dispatch level of the facility. Variable energy fees are paid when the facility generates electricity. Currently, approximately 90% of the revenues with respect to our Philippine operations come from fixed capacity charges. Nearly all of the capacity fees of Sual and Pagbilao are denominated in U.S. dollars. Energy fees and a portion of the capacity fees have both U.S. dollar and Philippine peso components that are indexed to inflation. The majority of the obligations of NPC under the energy conversion agreements are guaranteed by the full faith and credit of the Philippine government.

The energy conversion agreements were executed under the BOT program. The energy conversion agreements for the Sual, Pagbilao and Ilijan facilities expire in October 2024, August 2025 and June 2022, respectively.

In addition to the energy conversion agreements with NPC, our Sual subsidiary has a joint marketing agreement with NPC for excess capacity of 218 MW. Currently, electricity from the excess capacity of our Sual facility is provided to selected customers such as economic zones, industrial customers and private electric distribution companies and cooperatives. As a result of outages at both units of the Sual plant, we are currently purchasing power from NPC to meet our supply obligations. See Sual Outages in Note 3 to the consolidated financial statements where the outages are discussed further.

Real property taxes in the Philippines are levied by applying a locally determined tax rate to the taxable value of property. We are currently the owner of record of the machinery and equipment on which real property taxes are levied but NPC is responsible for payment of real property taxes under the energy conversion agreements for our Pagbilao and Sual power facilities. See Note 3 to the consolidated financial statements contained elsewhere in this report for further discussion of the real property taxes applicable to these facilities.

Caribbean

Our net ownership interest in the generating capacity of our Caribbean plants is 1,050 MW.

Jamaica Public Service Company Limited. We own an 80% interest in JPS, a fully integrated electric utility company that generates, transmits, distributes and sells electricity on the island of Jamaica. JPS operates under a 20-year All-Island Electric License (the License) that expires in 2021 and that provides JPS with the exclusive right to sell power on a retail basis in Jamaica. Under the provisions of the License, JPS is granted the exclusive right to transmit, distribute and supply electricity throughout the island of Jamaica. JPS also has the right to develop new generation capacity subject to a requirement that expansion projects in excess of 20 MW be subjected to a competitive tendering process. In instances of force majeure, the Office of Utilities and Regulation (the OUR) may waive the requirements for competitive tendering. JPS has installed generation capacity of 603 MW, and purchases an additional 196 MW of firm capacity from three independent power producers under long-term purchase agreements and an additional 20 MW of energy from a wind farm on an as-available basis. JPS supplies electric power to approximately 571,000 residential, commercial and industrial customers in Jamaica. JPS is regulated by the OUR under a price cap model with rate cases held every five years and with interim adjustments for changes in inflation, fuel prices, purchase power costs, foreign exchange movements and certain efficiency measures. JPS completed its most recent rate case in June 2004.

Grand Bahama Power Company. We own a 55.4% interest in Grand Bahama Power, a 151 MW integrated electric utility company that generates, transmits, distributes and sells electricity on Grand Bahama Island. Grand Bahama Power has the exclusive right and obligation to supply electric power to the residential, commercial and industrial customers on Grand Bahama Island. As of December 31, 2006, Grand Bahama Power has approximately 19,000 customers. Grand Bahama Power s rates are set by the Grand Bahama Port Authority.

The Power Generation Company of Trinidad and Tobago. We own a 39% interest in PowerGen, a power generation company that owns and operates three power plants located on the island of Trinidad. The electricity produced by PowerGen is provided to T&TEC, which serves approximately 347,000 customers on the islands of Trinidad and Tobago and which holds a 51% interest in PowerGen. PowerGen has a power purchase agreement for approximately 820 MW of capacity and spinning reserve with T&TEC that expires in 2009 and is guaranteed by the government of Trinidad and Tobago. Under this contract, the fuel is provided by T&TEC.

On December 6, 2005, PowerGen and T&TEC executed a 30-year 208 MW power sales agreement. On February 23, 2006, PowerGen began construction of the facility that is to supply the power to be provided under this agreement and estimates a commercial operations date of March 2007.

Curacao Utilities Company. We own a 25.5% interest in CUC at the Isla Refinery in Curacao, Netherlands Antilles. The 153 MW facility provides electricity, steam, desalinated water and compressed air to the refinery and up to 45 MW of electricity to the Curacao national grid.

At December 31, 2006, CUC was in technical default under its $84 million senior debt facility due to delays in completion of generation facilities. To date, CUC s lenders have not exercised their right to terminate the debt facility. CUC is currently pursuing an amendment and a waiver from the lenders and expects to receive it in the first quarter of 2007. In the event the issue is not resolved, our annual dividend payments from this investment may be at risk.

Aqualectra. We own a $40 million convertible preferred equity interest in Aqualectra, an integrated water and electric company in Curacao, Netherlands Antilles, owned by the government. Aqualectra has

electric generating capacity of 235 MW and drinking water production capability of 69,000 cubic meters per day. Aqualectra serves approximately 65,000 electricity and water customers. We receive 16.75% preferred dividends on our $40 million investment on a quarterly basis. As described below, Aqualectra has not paid our September and December 2006 preferred dividends because it is in default under its $87 million credit facility. Aqualectra has a call option and we have a put option, both of which are exercisable through December 31, 2007. We also have an option to convert our convertible preferred equity interest in Aqualectra to common shares through December 31, 2007. Neither we nor Aqualectra have exercised such options at this time.

At December 31, 2006, Aqualectra was in default under its $87 million credit facility because of breaches in financial covenants. Aqualectra is in breach of these covenants primarily due to its inability to pass through escalating fuel costs to its customers. Aqualectra has been in default for breaching these debt covenants in the past but has received waivers from the lenders which allowed the payment of our preferred dividends. A primary condition of the bank waiver was the existence of the energy fund. The energy fund, established by the Island Council and Executive Council of the Island Territory of Curacao, was intended to stabilize the prices of the energy related products on the island for the period 2005 through 2006. The energy fund was designed to provide Aqualectra with recovery of its fuel costs in excess of those recovered from its customers for the period from January 2005 through December 2006. As of December 31, 2006, the energy fund was depleted. The depletion of the fund has caused the bank waiver of the debt covenant breach to expire. Aqualectra requested a waiver from the lenders related to its financial covenant breaches but the lenders have declined to give a waiver until the energy fund is funded by the Curacao government or the Curacao government provides for an increase in the Aqualectra rate structure to allow for the full recovery of its fuel costs. As of December 31, 2006, dividend payments from Aqualectra totaling approximately $3 million are in arrears. Resolution of this issue could take several months and consequently, the receipt of the March 2007 dividend payment could be delayed.

U.S. Natural Gas-Fired Assets

Our six U.S. natural gas-fired intermediate and peaking facilities have a total capacity of 3,619 MW.

The Zeeland facility, located in Zeeland, Michigan, is comprised of simple cycle units totaling 327 MW of capacity and a 576 MW combined cycle facility (903 MW of total capacity). The Zeeland facility is interconnected with the International Transmission Company, which is a member of the MISO and operates under the East Central Area Reliability Coordination Agreement.

The West Georgia facility in Thomaston, Georgia, and the Shady Hills facility in Pasco County, Florida, consist of gas and oil-fired combustion turbines with capacities of 613 MW and 469 MW, respectively. They operate in the Southeastern Electric Reliability Council. Currently, there is no ISO in the Southeastern Electric Reliability Council.

West Georgia has a PPA for a portion of the output of the West Georgia facility that will expire in May 2009. The annual capacity amount nominated by West Georgia is approximately 448 MW. West Georgia receives a capacity payment, start-up payments, and variable operating and maintenance payments on a per MWh basis, and an index-based fuel payment. The PPA allows West Georgia to provide replacement energy from the market to meet its contractual obligations. West Georgia may receive bonuses or incur penalties for availability outside allowable limits. There are no provisions for renewal or extension of the contract. Output of the West Georgia facility not covered by the PPA is sold into the wholesale market by Mirant Energy Trading.

West Georgia has a fuel supply contract which expires in May 2009. West Georgia also has purchased firm gas transportation for 22,500 MMbtu/day for the months of June through September under an agreement that expires in May 2009.

Shady Hills has a tolling agreement with a counterparty that runs through March 2007 for all of the facility s output. A second tolling agreement, which runs through April 2024, will begin at the expiration of the existing agreement. Pursuant to the tolling arrangements, Shady Hills receives a monthly capacity payment, a variable operating and maintenance payment on a per MWh basis, and a start-up payment each time a unit is turned on. The counterparty schedules and delivers all fuel. Shady Hills generates electricity and provides a heat rate and availability guarantee and may receive bonuses and pay penalties when its performance is outside the guaranteed values.

The Sugar Creek facility is a 561 MW combined cycle facility located in West Terre Haute, Indiana. The Sugar Creek facility has the physical capability to be interconnected with either the Cinergy or AEP systems. Cinergy is a member of the MISO, and AEP is a member of the PJM market. The facility is eligible to participate in the energy, capacity and ancillary markets of PJM and MISO.

The Bosque facility located in Laguna Park, Texas, consists of a gas-fired combustion turbine with a corresponding steam turbine with a capacity of 239 MW that is available to serve baseload and intermediate demand. Additionally, Bosque units 1 and 2 are gas-fired peaking facilities with a total capacity of 307 MW. The Bosque facility operates in the ERCOT market. For a discussion of ERCOT, see Regulatory Environment below.

The Apex facility is a 527 MW intermediate gas-fired combined-cycle facility located near Las Vegas, Nevada. Mirant Energy Trading has signed contracts with a third party for 225 MW of capacity and energy from the Apex facility for the period from May 2003 to April 2008.

Regulatory Environment

The electricity industry is subject to comprehensive 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. Any of our subsidiaries that owns a generating facility selling at wholesale or that markets electricity at wholesale outside of ERCOT 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 are subject to FERC oversight of mergers and acquisitions, the disposition of FERC-jurisdictional facilities and the issuance of securities. In addition, under the Natural Gas Act, the FERC has limited jurisdiction over certain resales of natural gas, but does not regulate the prices received by our subsidiary that markets natural gas.

The FERC has authorized our subsidiaries that constitute public utilities under the Federal Power Act to sell energy and capacity at wholesale at market-based rates and has authorized some of these subsidiaries to sell certain ancillary services at wholesale at market-based rates. The majority of the output of the generation facilities owned by our United States subsidiaries that constitute public utilities is sold pursuant to this authorization, although certain of our facilities sell their output under cost-based RMR agreements, as explained below. The FERC may revoke or limit our market-based rate authority if it determines that we possess undue market power in a regional market. The FERC requires that our subsidiaries with market-based rate authority, as well as those with blanket certificate authorization permitting market-based sales of natural gas, adhere to certain market behavior rules and codes of conduct, respectively. If any of our subsidiaries violates the market behavior rules or codes of conduct, the FERC may require a disgorgement of profits or revoke its market-based rate authority or blanket certificate authority. If the FERC were to revoke market-based rate authority, our affected subsidiary would have to file a cost-based rate schedule for all or some of its sales of electricity at wholesale. If the FERC revoked the blanket certificate authority of any of our subsidiaries, certain sales of natural gas would be prohibited.

Our facilities operate in ISO/RTO markets. In areas where ISOs or RTOs control the regional transmission systems, market participants have expanded access to transmission service. ISOs operate real-time and day-ahead energy and ancillary services markets, typically governed by FERC-approved tariffs and market rules. Some RTOs and ISOs also operate capacity markets. Changes to the applicable tariffs and market rules may be requested by market participants, state regulatory agencies and the system operator, and such proposed changes, if approved by the FERC, could have a significant impact on our operations and business plan. While participation by transmission-owning public utilities in ISOs and RTOs has been and is expected to continue to be voluntary, the majority of such public utilities in New England, New York, the Mid-Atlantic and California have joined the respective ISO/RTO.

Our subsidiaries owning generation in the United States were exempt wholesale generators under the PUHCA, as amended, and all of our subsidiaries owning generation outside the United States were either foreign utility companies or exempt wholesale generators. With the repeal of the PUHCA and the adoption of the Public Utility Holding Company Act of 2005, the FERC adopted new regulations effective February 8, 2006, that allow our subsidiaries owning generation in the United States to retain their exempt wholesale generator status as well as allow our subsidiaries owning generation outside of the United States to remain either foreign utility companies or exempt wholesale generators.

State and local regulatory authorities have historically 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 generation may be subject to a variety of state and local regulations, including regulations regarding the environment, health and safety, maintenance and expansion of generation facilities. To the extent that a subsidiary sells electricity at retail in a state with a retail access program, it may be subject to state certification requirements and to bidding rules that provide default service to customers who choose to remain with their regulated utility distribution companies.

Mid-Atlantic Region. Our Mid-Atlantic facilities sell power into the markets operated by PJM, which the FERC approved to operate as an ISO in 1997 and as an RTO in 2002. 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 generators. PJM administers day-ahead and real-time marginal cost 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 cheaper power cannot be imported from another zone. Generation owners in PJM are subject to mitigation, which limits the prices that they may receive under certain specified conditions.

Load-serving entities within PJM are required to have adequate sources of capacity. PJM operates a capacity market whereby load-serving entities can procure their capacity requirements through a system-wide single clearing price auction. In PJM, all capacity is assumed to be universally deliverable, regardless of its location. PJM has greatly expanded its system to include Allegheny Power, Commonwealth Edison, AEP, DP&L and Dominion-Virginia Power. As a result, capacity prices have significantly declined. The PJM expansions have resulted in an apparent system-wide surplus of capacity, despite the fact that certain regions in PJM-Mid-Atlantic are currently in need of capacity additions.

On December 22, 2006, the FERC approved, with conditions, a settlement between PJM and multiple market participants regarding PJM s RPM, which was originally filed with the FERC on August 31, 2005, to replace the existing system-wide single clearing price capacity market. The RPM settlement is intended to ensure reliability and reasonable rates in the PJM region. The RPM settlement provides for a three-year forward capacity auction using a modified demand curve from the original RPM filing and locational deliverability zones that will be phased in over several years. Demand curves are administrative mechanisms used to establish electricity generation capacity prices. The RPM settlement will provide increased opportunities for our power plants located in the Mid-Atlantic region to receive more revenues for their capacity. The order approving the RPM is subject to rehearing and a motion to vacate. Parties opposed to the RPM settlement have filed requests with the FERC to rehear, vacate or stay the effectiveness of the December 22, 2006, order, which are currently pending before the FERC.

In addition, PJM and the MISO have been directed by the FERC to establish a common and seamless market, an effort that is largely dependent upon the MISO s ability to first establish and operate its markets. The development of a joint market is contingent on the approval of the internal costs to both entities to develop and operate the infrastructure necessary for joint operations. It is unclear at this time if either the respective entities or the FERC will approve such costs to achieve a common and seamless market.

Northeast Region. Our New York plants participate in a market controlled by the NYISO, which replaced the New York Power Pool. 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 that is similar to that used in PJM and ISO-NE. 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 facilities operate outside of New York City and Long Island. On April 21, 2005, the FERC issued an order accepting the NYISO s demand curves for capability years 2005/2006, 2006/2007 and 2007/2008 with minor modifications to the NYISO s proposal. The new demand curves may result in increased prices within the NYISO for capacity.

Our New England plants 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 effective on February 1, 2005, making ISO-NE responsible for market rule filings at the FERC, in addition to its responsibilities for the operation of transmission systems and administration and settlement of the wholesale electric energy, capacity and ancillary services markets. ISO-NE utilizes a locational marginal pricing model similar to that used in PJM and NYISO. In early 2004, ISO-NE filed with the FERC to adopt a LICAP similar to NYISO s capacity market. After extensive litigation before the FERC on the LICAP proposal, on March 6, 2006, a comprehensive settlement proposal was filed with the FERC between ISO-NE and multiple market participants that would replace the LICAP proposal with a forward capacity market (FCM) under which annual capacity auctions would be conducted for supply three years in advance of delivery. In addition, the settlement provided for a four-year transition period under which capacity suppliers would receive a set price for their capacity commencing on December 1, 2006, and continuing with price escalators through May 31, 2010. On June 16, 2006, the FERC issued a decision accepting the proposed FCM settlement without modification. The FCM will result in increased opportunities for our New England generators to receive more revenues for their capacity commencing in December 2006. The FERC S orders regarding the LICAP and FCM are pending review with the U.S. Court of Appeals. On February 15, 2007, ISO-NE filed the market rules with the FERC to implement FCM. The market rules were supported by a majority of NEPOOL members. NEPOOL did not join in the filing but will be filing separate comments. Existing resources will need to be qualified, and the amount of MW they have to participate in the first auction certified, by April 2007. In June 2007, another round of information will be due from new generators, on a more detailed and binding nature than the show of interest forms. In October, 2007 all resources that want to participate in the first auction will be fully qualified by ISO-NE. The first auction will take place starting February 4, 2008, for the delivery period June 1, 2010 - May 31, 2011.

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 generation output is sold in the real-time market. The CAISO does not operate a forward market like those described for PJM and other Eastern ISO markets, nor does it currently operate a capacity market.

Our subsidiaries owning facilities subject to RMR arrangements are parties to a PPA with PG&E that allows PG&E to dispatch and purchase the power output of all of our CAISO designated RMR units from 2006 through 2012. The PPA currently applies only to Potrero units 3-6, our CAISO designated RMR generating units for 2007. Under the PPA, through 2008 PG&E is paying us charges equivalent to the rates we charged during 2004 when the units were designated RMR Contract Condition 2 reduced by $1.4 million for each year. For 2009 through 2012, the charges for the units that are then subject to the PPA will be determined annually by the FERC.

The CAISO has proposed changes to its market design to more closely mirror the eastern ISO markets, including establishing a wholesale capacity market. The market redesign has been delayed several times, with full implementation now expected in 2008. Any proposal for a capacity market in California is subject to filing with and approval by the FERC, and at this time, the CAISO has not proposed a capacity market mechanism in its market redesign. The CPUC has taken a role in developing recommended options with respect to a wholesale capacity market in conjunction with the CAISO. We cannot at this time predict the outcome of the CPUC proceeding or the timing or structure of a wholesale capacity market in California.

The FERC approved a $400 per MWh cap, effective on January 1, 2006, on prices for energy in the CAISO market, which was an increase from the previous $250 per MWh cap, but still far short of the $1,000 per MWh energy cap utilized in the other FERC approved RTO markets. In addition, owners of non-hydroelectric generation in California, including certain of our facilities, must offer to keep their generation on-line and stand ready to offer power into the CAISO s spot markets if the output is not under contract or scheduled for delivery within the hour, unless granted a waiver by the CAISO. The practical effect of this rule is to obtain operating reserves without paying for them, and to release excess energy into the market, thereby depressing prices. On August 26, 2005, the Independent Energy Producers, a trade association, filed a complaint with the FERC, requesting that the FERC require the CAISO to implement a reliability capacity services tariff (RCST) that would pay generators for the capacity obtained pursuant to the must-offer requirement. Prior to the FERC s ruling on the merits of the complaint, the CAISO and multiple market participants filed a settlement that would implement a form of the RCST. On February 13, 2007, the FERC approved the RCST settlement with minor modifications with an effective date of June 1, 2006. The RCST settlement may result in increased capacity revenue opportunities for generators and possibly could increase revenues for certain units at our Pittsburg and Contra Costa plants for the June 1 - December 31, 2006, period, depending upon how the CAISO implements the terms of the settlement. However, after December 31, 2006, our Pittsburg and Contra Costa plants are under contract for varying periods from now until 2011, and we will not realize any opportunities from RCST until those contracts expire.

The CPUC has issued a series of orders purporting to require exempt wholesale generators and other power plant owners to comply with detailed operation, maintenance and recordkeeping standards for electricity generating facilities. In its orders, the CPUC has stated its intent to implement and enforce these detailed standards to maintain and protect the public health and safety of California residents and businesses, to ensure that electric generating facilities are effectively and appropriately maintained and efficiently operated, and to ensure electrical service reliability and adequacy. The CPUC has adopted detailed reporting requirements for the standards, and conducts frequent on-site spot inspections and more comprehensive facility audits to evaluate compliance. Some standards are intended to ensure that units are maintained in a state of readiness so as to be available to operate if requested by a control area operator, while others provide procedures for changing a unit s long-term status. The CPUC s efforts to implement and enforce the operation, maintenance and recordkeeping standards could interfere with our future ability to make economic business decisions regarding our units, including decisions regarding unit retirements, and could have a material adverse impact on our business activities in California.

Environmental Regulation

Our business is subject to extensive environmental regulation by federal, state and local authorities. This requires us to comply with applicable laws and regulations, and to obtain and comply with the terms of government issued permits. Our costs of complying with environmental laws, regulations and permits are substantial. We expect that cash flows from operations will be sufficient to fund these capital expenditures.

Maryland Healthy Air Act. On August 3, 2006, we announced a plan to comply with the requirements of the Maryland Healthy Air Act by reducing SO2 emissions by as much as 95% at our Maryland power plants. We will install flue gas desulphurization (FGD) emissions controls at our Chalk Point, Dickerson and Morgantown plants. In addition, we will install selective catalytic reduction (SCR) systems at the Morgantown (as contemplated by the pending NOx Consent Decree described in Item 3. Legal Proceedings, Environmental Matters) and Chalk Point facilities that will reduce NOx emissions by approximately 80%. Together, the FGDs and the SCRs will reduce by approximately 80% the emissions of ionic mercury from the three Maryland power plants.

The Maryland Healthy Air Act requires deeper reductions in NOx and SO2 in 2010 and 2015 than reductions required under federal law including the CAIR. As a result of passage of the more restrictive Maryland state standard on NOx and SO2 emissions, our plan to install control equipment will allow the Maryland facilities to meet or exceed the CAIR limits. We anticipate that the capital expenditures to achieve compliance for SO2 and NOx emissions will be approximately $1.6 billion through 2009. The Maryland Healthy Air Act also requires reductions of mercury emissions by the year 2010. As a result of our installation of equipment to satisfy the more restrictive Maryland state standard on mercury emissions, our Mid-Atlantic facilities will also meet or exceed the CAMR limits. The state law also requires Maryland to join the Regional Greenhouse Gas Initiative (RGGI), a seven state plan to reduce CO2 emissions by 2018. The State of Maryland will initiate a rule-making proceeding in 2007 to determine the regulatory framework for RGGI participation.

At the federal level, there are efforts to pass legislation to mandate reductions of CO2 emissions from generation facilities. There are several pieces of legislation being advanced that vary in levels of reductions and mechanisms for compliance.

Air Emissions Regulations. Our most significant environmental requirements in the United States generally fall under the Clean Air Act 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. Several of our facilities are located in or near metropolitan areas, such as New York City, Boston, San Francisco and Washington D.C., which are classified by the EPA as not achieving certain NAAQS. As a result of the NAAQS classification of these areas, our operations are subject to more stringent air pollution requirements, including, in some cases, further emissions reductions. In the future, we anticipate increased regulation of generation facilities under the Clean Air Act and applicable state laws and regulations concerning air quality. Significant air regulatory programs to which we are subject include those described below.

Clean Air Interstate Rule (CAIR). In May 2005, the EPA promulgated the CAIR regulations, which established in the eastern United States an SO2 and NOx cap-and-allowance trading program applicable to generation facilities. These cap-and-trade programs will be implemented in two phases, with the first phase going into effect in 2010 and more stringent caps going into effect in 2015. In order to comply with the first phase of those regulations, we will have to install additional pollution control equipment and/or purchase additional emissions allowances, at significant cost. We are planning to install pollution control equipment at some of our facilities to address, in part, our requirements under the first phase of the CAIR. The costs of that equipment are included in our estimate of anticipated environmental capital expenditures from 2007 through 2010. However, since the determination of how much pollution control equipment to install is based upon factors such as the cost of emissions allowances and the operational demands on our generation facilities, our plans may change significantly. For our Maryland facilities, compliance with the Maryland Healthy Air Act meets or exceeds the requirements under CAIR.

Clean Air Mercury Rule (CAMR). In May 2005, the EPA issued the CAMR, which limits total annual mercury emissions from coal-fired power plants across the United States through a two-phased cap-and-trade program. The first phase begins in 2010 and the second phase begins in 2018. The EPA expects that, in the first stage, the necessary reductions in mercury will be achieved as a co-benefit using the same pollution control equipment required to achieve the reductions of SO2 and NOx under the CAIR. All states are required to adopt either the EPA rule or a state rule meeting the minimum requirements outlined in the CAMR. Under the EPA rule, we will receive an allocation of mercury emissions allowances associated with our coal-fired plants nationwide, unless there are restrictions imposed at the state level. We expect our coal-fired facilities to comply with the CAMR regulations by taking advantage of the co-benefits derived from NOx and SO2 controls that are, or will soon be, installed.

NSR enforcement initiative. In 1999, the DOJ, on behalf of the EPA, commenced enforcement actions against a number of companies in the power generation industry for alleged violations of the NSR regulations, which require permitting and impose other requirements for certain maintenance, repairs and replacement work on facilities. These enforcement actions can result in a facility owner having obligations to, among other things, install emissions controls at significant cost. These enforcement actions were broadly challenged by the industry in the courts, among other reasons, for being a new interpretation of longstanding regulations. In an effort to provide additional clarity, it is expected that in 2007 the Bush administration will adopt new air pollution rules to clarify what constitutes an emissions increase under the NSR program.

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 plants. If a violation is determined to have occurred at any of the plants, our subsidiary owning or leasing the plant 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 plants in Maryland will be installing a variety of emissions control equipment on those plants to comply with the Maryland Healthy Air Act, but that equipment may not include all of the emissions control equipment that would be required if a violation of the EPA s NSR regulations is determined to have occurred at one or more of those plants. If such a violation is determined to have occurred after our subsidiaries acquired or leased the plants or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, our subsidiary owning or leasing the plant 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 plant, 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 plants.

State air regulations. Various states where we do business also have other air quality laws and regulations with increasingly stringent limitations and requirements that will become applicable in future years to our facilities and operations. We expect to incur additional compliance costs as a result of these additional state requirements, which could include significant expenditures on emissions controls or have other impacts on operations. Specific state items include:

Virginia CAIR and CAMR Implementation. In April 2006, Virginia enacted the Clean Smokestacks Law, which granted the Virginia State Air Pollution Control Board the discretion to limit the ability of a facility in a non-attainment area to purchase additional mercury, SO2 and NOx allowances to achieve compliance with CAIR and CAMR. The State Air Pollution Control Board has approved the implementing regulations to the Clean Smokestacks Law but they have not yet been promulgated. The State Air Pollution Control Board has interpreted the current form of these regulations as restricting facilities in non-attainment areas from purchasing emission allowances to achieve compliance with CAIR and CAMR. If the regulations are promulgated in their current form and the State Air Pollution Control Board s interpretation is correct, such restrictions would reduce our flexibility in complying with CAIR and CAMR and could result in operating restrictions for our Potomac River generating facility in Virginia.

Massachusetts Emissions Standards for Power Plants. The Commonwealth of Massachusetts has finalized regulations to further reduce NOx emissions from certain generation facilities. The Massachusetts regulations relate to NOx emissions during ozone season and become effective in 2009. Our operations will not be materially affected by the newly established limits.

New York. 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. On June 11, 2003, Mirant New York, Mirant Lovett and the State of New York entered into the 2003 Consent Decree. The 2003 Consent Decree was approved by the Bankruptcy Court on October 15, 2003. Under the 2003 Consent Decree, Mirant Lovett has three options: (1) install emissions controls on Lovett s two coal-fired units; (2) shut down one unit and convert one unit to natural gas; or (3) shut down both coal burning units in 2007 and 2008. If Mirant Lovett elects to install emissions controls on its two coal-fired units by 2007 through 2008, it must install: (a) emissions controls consisting of SCR technology to reduce NOx emissions; (b) alkaline in-duct injection technology to reduce SO2 emissions; and (c) a baghouse. Additionally, in 2003, the State of New York finalized air regulations that significantly reduced allowances for NOx and SO2 emissions from generation facilities through a state emissions cap-and-trade program, which will become effective during the 2006-2008 timeframe.

On October 19, 2006, Mirant Lovett notified the New York Public Service Commission, the NYISO, Orange and Rockland and certain other affected transmission and distribution companies in New York of its intent to discontinue operation of units 3 and 5 of the Lovett facility in April 2007. The 2003 Consent Decree imposes similar requirements with respect to unit 4 that have to be met by April 30, 2008.

Climate change. Concern over climate change has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

In 1998, the United States became a signatory to the Kyoto Protocol of the United Nations Framework Convention on Climate Change. The Kyoto Protocol, which became effective in February 2005 after Russia s ratification in November 2004, calls for developed nations to reduce their emissions of greenhouse gases to 5% below 1990 levels by 2012. CO2, which is a major byproduct of the combustion of fossil fuel, is a greenhouse gas that would be regulated under the Kyoto Protocol. The United States Senate indicated that it would not enact the Kyoto Protocol, and in 2002 President Bush confirmed that the United States would not enter into the Kyoto Protocol. Instead, the President indicated that the United States would support voluntary measures for reducing greenhouse gases and technologies that would use or dispose of CO2 effectively and economically. As the Kyoto Protocol becomes effective in other countries, there is increasing pressure for sources in the United States to be subject to mandatory

restrictions on CO_2 emissions. In the last year, the United States Congress has considered bills that would regulate domestic greenhouse gas emissions, but such bills have not received sufficient Congressional approval to date to become law. If the United States ultimately ratifies the Kyoto Protocol and/or if the United States Congress or individual states or groups of states in which we operate ultimately pass legislation regulating the emissions of greenhouse gases such as the RGGI discussed below, any resulting limitations on generation facility CO_2 emissions could have a material adverse impact on all fossil fuel- fired generation facilities (particularly coal-fired facilities), including ours.

On August 16, 2006, a model rule was finalized and seven states in the Northeast will move forward with the implementation of the RGGI. This is a multi-state regional initiative that uses a regional cap-and-trade program to reduce CO_2 emissions from power plants of 25 MW or greater. The program aims to stabilize CO_2 emissions to current levels from 2009 to 2015. This is to be followed by a 10% reduction in emissions by 2019. At this time, our assets in Maryland, Massachusetts and New York will be affected, and we are evaluating our options to comply with the requirements of the rule.

In addition, separate from the RGGI, California and Massachusetts have also enacted limitations on CO_2 emissions from power plants which affect our gas-fired plants in California and our Canal facility in Massachusetts. We expect that we will be able to comply with these restrictions either by reducing our emissions or purchasing emissions credits if permitted by the applicable law, but if we are unable to comply, we will be forced to curtail our operations at these facilities.

At the federal level Congress is expected to advance several mandatory CO_2 bills, which may require reductions of CO_2 emissions nationwide.

Water regulations. We are required under the Clean Water Act to comply with effluent and intake requirements, technological controls requirements and operating practices. Our wastewater discharges are subject to permitting under the Clean Water Act, and our permits under the Clean Water Act are subject to review every five years. As with air quality regulations, federal and state water regulations are expected to increase and impose additional and more stringent requirements or limitations in the future. This is particularly true for regulatory requirements governing cooling water intake structures, which are subject to regulation under section 316(b) of the Clean Water Act. A recent decision by the United States Court of Appeals for the Second Circuit in *Riverkeeper Inc. et al v. EPA*, in which the court remanded numerous provisions of the EPA s current 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. Until the EPA acts on the issues remanded, it is impossible to say exactly what requirements will be imposed or what they will cost.

In February 2006, Mirant Delta received correspondence from the U.S. Fish and Wildlife Service and the U.S. Army Corps of Engineers expressing the view that the federal Endangered Species Act coverage for our Contra Costa and Pittsburg facilities located along the Sacramento River and Suisun Bay is insufficient or inoperative. Endangered Species Act consultation has been formally reinitiated, and we are continuing to work with these agencies to resolve these issues. It is possible, however, that we will be unable to resolve these issues with the agencies and that more formal legal action may be instituted against us resulting in substantial fines or operational curtailment of these facilities.

On May 10, 2006, the San Francisco Regional Water Quality Control Board issued Mirant Potrero a National Pollution Discharge Elimination System permit pursuant to the Clean Water Act regulating the Potrero facility s cooling water and process water discharges to the San Francisco Bay. Communities for a Better Environment, an environmental advocacy organization, contested various elements of the permit in a petition filed with the California State Water Resources Control Board on June 8, 2006, seeking relief that could include a plant curtailment, and/or costly technological upgrades. Mirant Potrero filed a timely response to this petition as the permit holder on November 27, 2006, in support of the Regional Board s permit decision. A decision from the State Board is expected by July 2007.

On September 26, 2006, the Massachusetts Department of Environmental Protection and the EPA jointly issued to Mirant Kendall a Surface Water Discharge Permit (SWDP) and a National Pollutant Discharge Elimination System (NPDES) permit for the Kendall generating facility. The new permit imposes in-stream temperature limits, 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 significant portions of the SWDP and NPDES permit, along with a related state Water Quality Certificate. The portions of the permits that Mirant Kendall has appealed are stayed pending appeal. We are unable to predict the outcome of this proceeding.

Wastes, hazardous materials and contamination. Our facilities are subject to several waste management laws and regulations in the United States. The Resource Conservation and Recovery Act of 1976 set forth 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 from these facilities. The EPA may develop new regulations that impose additional requirements on facilities that store or dispose of fossil fuel combustion materials, 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 for increased waste management requirements.

Additionally, CERCLA, or Superfund, establishes a 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. Areas of soil and groundwater contamination are known to exist at our Pittsburg, Contra Costa and Potrero facilities. Prior to our acquisition of those facilities from PG&E in 1998, PG&E conducted soil and groundwater investigations at those facilities which revealed significant 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 at the Potrero generating facility and the disposition of up to 60,000 cubic yards of contaminated soil at the Potrero generating facility and the remediation of any groundwater or solid contamination identified by PG&E at the Pittsburg and Contra Costa generating facilities. Pursuant to our requests, PG&E has disposed of 807 cubic yards of contaminated soil at the Potrero generating facility. We are not aware of soil or groundwater conditions for which we expect our remediation costs to be material that are not covered by third-party agreements.

Employees

At December 31, 2006, our corporate offices and majority owned or controlled subsidiaries employed approximately 4,440 people. This number includes approximately 1,820 employees in the United States, approximately 1,620 employees in the Caribbean, and approximately 1,000 employees in the Philippines. The following details the employees subject to collective bargaining agreements:

Union	Location	Number of Employees Covered	Contract Expiration Date
Continuing Operations:			
IBEW Local 1900	Maryland and Virginia	482	6/1/2010
IBEW Local 503	New York	136	6/1/2008
IBEW Local 1245	California	123	10/31/2008
UWUA Local 369	Cambridge, Massachusetts	34	2/28/2009
UWUA Local 480	Sandwich, Massachusetts	51	6/1/2011
Total		826	
Discontinued Operations:			
IBEW Local 396	Nevada	18	7/28/2008
United Steel Workers Local 12502(1)	Indiana and Michigan	27	1/1/2007
Bahamas Industrial Engineers, Managerial, and Supervisory Union(2)	Grand Bahama	36	1/1/2005
Commonwealth Electrical Workers Union(3)	Grand Bahama	135	3/31/2005
Jamaica Public Service Managers Association	Jamaica	165	11/30/2007
Union of Clerical Administrative & Supervisory Employees; National Workers Union; Bustamante Industrial Trade Union	Jamaica	1,057	12/31/2007
Petroleum Workers Federation of Curacao(4)	Curacao	37	
Total		1,475	

(1) One year contract extension through 1/1/2008.

(2) Union negotiations are at a stalemate. Overall, the industrial climate is stable.

(3) Negotiations are ongoing.

(4) Initial contract under negotiation.

To mitigate and reduce the risk of disruption during labor negotiations, we engage in contingency planning for continuation of our generation and/or distribution activities to the extent possible during an adverse collective action by one or more of our unions. If our non-unionized workforce moved toward unionization, we could be materially affected through increased employee costs, work stoppages or both.

Item 1A Risk Factors

The following are factors that could affect our future performance:

Our revenues are unpredictable because many 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 many of our generating facilities into competitive power markets on a short-term fixed price basis or through power sales agreements. 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, the marginal and long run costs incurred by our competitors and the impact of market regulation. Lack of diversification in revenue may also result in concentrated exposure to markets, especially PJM. The price for which we can sell our output may fluctuate on a day-to-day basis. 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, limiting 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 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 sufficient for recovery of our costs, our investment and an adequate return on our investment;

- 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, refusal by regulators to allow utilities to fully recover their wholesale power costs and investments through rates, catastrophic losses and losses from investments in unregulated businesses;

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

- increases in supplies due to actions of our current competitors or new market entrants, including the development of new generating facilities 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;

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

- existing or future regulation of our markets by the FERC, ISOs and RTOs, including any price limitations and other mechanisms to address some of the price volatility or illiquidity in these markets or the physical stability of the system;

- 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;

- weather conditions that depress demand or increase the supply of hydro power; and

- changes in the rate of growth in electricity usage as a result of such factors as regional economic conditions and implementation of conservation programs.

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.

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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, and we may be unsuccessful at managing this risk.

Our generation business is subject to changes in power prices and fuel costs, which 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. In addition, actual power prices and fuel costs may differ from our expectations.

Mirant Energy Trading engages in asset management activities related to sales of electricity and purchases of fuel. The income and losses from these activities are recorded as generation revenues and fuel costs. Mirant Energy Trading may use forward contracts and derivative financial instruments to manage market risk and exposure to volatility in electricity, coal, natural gas, emissions and oil prices. 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 and fuel markets.

Many factors influence commodity prices, including weather, market liquidity, transmission and transportation inefficiencies, availability of competitively priced alternative energy sources, demand for energy commodities, natural gas, crude oil and coal production, natural disasters, wars, embargoes and other catastrophic events, and federal, state and foreign energy and environmental regulation and legislation.

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. As a result of these and other factors, we cannot predict the impact that risk management decisions may have on our businesses, operating results or financial position. Although management devotes a considerable amount of 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 natural gas, coal and oil fuel supply.

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.

Some of our generation facilities depend on only one or a few customers or suppliers. These parties, as well as other parties with whom we have contracts, may fail to perform their obligations, or may terminate their existing agreements, which may result in a default on project debt or a loss in revenues and may require us to institute legal proceedings to enforce the relevant agreements.

Several of our power production facilities depend on a single customer or a few customers to purchase most or all of the facility s output or on a single supplier or a few suppliers to provide fuel, water and other services required for the operation of the facility. The sale and procurement agreements for these facilities may also provide support for any project debt used to finance the facilities. The failure of any supplier or customer to fulfill its contractual obligations to the facility could have a material adverse effect on such facility s financial results. The financial performance of these facilities is dependent on the continued performance by customers and suppliers of their obligations under their long-term agreements.

Revenue received by our subsidiaries may be reduced upon the expiration or termination of existing power sales agreements. Some of the electricity we generate from our existing portfolio is sold under long-term power sales agreements that expire at various times. When the terms of each of these power sales agreements expire, it is possible that the price paid to us for the generation of electricity may be reduced significantly, which would substantially reduce our revenue.

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

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

- the output and efficiency levels at which those generation facilities perform;
- interruptions in fuel supply;
- disruptions in the delivery of electricity;
- adverse zoning;
- breakdowns or equipment failures (whether due to 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;
- shortages of equipment or spare parts;
- labor disputes;
- operator errors;
- curtailment of operations due to 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.

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

We engage in asset management activities to economically hedge our exposure to market risk with respect to: (1) electricity sales from our generation 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 contracts. We also use derivative contracts 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 and proprietary trading activities are recorded on our balance sheet at fair value pursuant to

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SFAS No. 133. None of our derivatives recorded at fair market value are designated as hedges under SFAS No. 133 and changes in their fair value 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 due to changes in forward electricity and fuel prices. For a more detailed discussion of the accounting treatment of our asset management and proprietary trading activities, see Note 7 to our consolidated financial statements, included herein.

Our results are subject to quarterly and seasonal fluctuations.

Our operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including:

- seasonal variations in demand and corresponding energy and fuel prices; and
- variations in levels of production.

We compete to sell energy and capacity 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 generation 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.

Operating in foreign countries involves a number of risks.

Our operations and earnings in the Philippines and Caribbean have been, and may in the future be, affected from time to time in varying degrees by political instability and by other political developments and laws and regulations which may affect both operations and financial affairs, such as forced divestiture of assets or required public offerings of equity interests in those assets; restrictions on production, imports and exports; war or other international conflicts; civil unrest and local security concerns that threaten the safe operation of company facilities; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights; currency fluctuations and environmental regulations. Both the likelihood of such occurrences and their overall effect upon us vary greatly from country to country and are not predictable.

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 operating permits and remain in continuous compliance with the conditions established by those operating permits. To comply with these legal requirements and the terms of our operating 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 and the imposition of liens or fines. In addition, we may be required to shut down facilities if we are unable to comply with the requirements, such as with CO2 regulations for which there currently is not a technical compliance solution, or if we determine the expenditures required to comply are uneconomic.

In addition, environmental laws, particularly with respect to air emissions, wastewater discharge and cooling water intake structures, are generally becoming more stringent, which may require us to make expensive facility upgrades or restrict our operations to meet more stringent standards. With the trend toward stricter standards, greater regulation, and more extensive permitting requirements, we expect our environmental expenditures to be substantial in the future. Although we have budgeted for significant expenditures to comply with these requirements, actual expenditures may be greater than budgeted amounts. We may have underestimated the cost of the environmental work we are planning or the air emissions allowances we anticipate buying. In addition, new environmental laws may be enacted, new or revised regulations under those laws may be issued, the interpretation of such laws and regulations by regulatory authorities may change, or additional information concerning the way in which such requirements apply to us may be identified. For example, in April 2006, Maryland enacted the Healthy Air Act, which requires more significant reductions in emissions of NOx, SO2 and mercury than the recently finalized CAIR and CAMR. This legislation affects our Chalk Point, Dickerson and Morgantown facilities. We anticipate that the capital expenditures to achieve compliance for SO2 and NOx emissions will be approximately $1.6 billion through 2009.

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 any environmental regulatory approvals or if onerous conditions are imposed, the operation of our generation facilities 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.

Certain environmental laws, including CERCLA and comparable state laws, impose strict and, in many circumstances, joint and several liability for costs of 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 generation 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 generation facilities, at disposal sites we currently utilize or have formerly utilized, 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. In the event that 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 additional emissions allowances to meet the mandated levels. To meet these requirements, we plan to install scrubbers on all of our Maryland coal facilities. We may not meet this construction schedule by January 2010 due to a number of factors, which may result in a loss of cash flows from operations due to reduced unit operations.

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

We expect that certain of our generation facilities and related properties will become subject to decommissioning and/or site remediation obligations that may require material expenditures. The exact amount and timing of such expenditures, if any, is not presently known. 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 level of 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 our obligations.

As of December 31, 2006, our total indebtedness for continuing operations was approximately $3.3 billion. In addition, the present value of lease payments under the Mirant Mid-Atlantic leveraged leases is approximately $1.1 billion (assuming a 10% discount rate) and the termination value of the Mirant Mid-Atlantic leveraged leases is $1.4 billion. Our substantial degree of leverage 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 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 (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 holding company subsidiaries, 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 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 United States operations is generated by the power generation 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 us. Mirant Mid-Atlantic s ability to satisfy the criteria set by that covenant in the future could be impaired by factors which negatively affect the performance of its power generation facilities, including interruptions in operation or curtailment of operations to comply with environmental restrictions.

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 indebtedness of their respective subsidiaries, except to the extent that such obligations or indebtedness are assumed or guaranteed by a subsidiary.

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

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 generation 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, 2006, we had approximately $227 million of posted cash collateral and $260 million of letters of credit outstanding primarily to support our asset management activities and debt service reserve requirements. 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.

If our facilities experience unplanned outages, we may be required to procure replacement power in the open market to satisfy contractual commitments. Without 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.

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 cost impacts, in turn, may negatively affect our financial condition and results of operations.

Generally, in the United States, 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 generation 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 generation 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 assets are subject to rules and terms of participation imposed and administered by various RTOs and ISOs. 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 and capacity.

Changes in the markets in which we compete may have an adverse impact on the results of our operations. For example, in the fall of 2004, PJM completed its integration of AEP, Duquesne Light and DP&L into PJM. Under PJM rules, AEP, Duquesne Light and DP&L were then deemed by PJM to be capable of providing capacity to all areas of PJM. The integration of these companies into PJM in conjunction with the existing market rules depressed the prices that can be charged for capacity in PJM.

To conduct our business, we must obtain 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.

On August 8, 2005, the EPAct 2005 was enacted. Among other things, the EPAct 2005 provides incentives for various forms of electric generation technologies, which will subsidize certain of our competitors. Many regulations that could be issued pursuant to the EPAct 2005 may have an adverse impact on our business.

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 both to advance and to roll back 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 suffer. 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.

We may be liable for certain underfunded liabilities with respect to pension plans offered by Mirant and its affiliates.

We and our affiliates offer pension benefits to employees through various pension plans. Funding obligations under the U.S. pension plans are governed by the ERISA and some of the plans are underfunded. As of December 31, 2006, our U.S. pension plans had an underfunded accumulated benefit obligation of approximately $59 million, and an underfunded projected benefit obligation of approximately $102 million, in aggregate as calculated in accordance with SFAS No. 158. As of December 31, 2006, our non-U.S. pension plans were overfunded on an accumulated benefit obligation basis by approximately $78 million, and on a projected benefit obligation basis by approximately $54 million, in the aggregate, as calculated in accordance with SFAS No. 158. Unless the underfunded liabilities are eliminated through asset returns, rising interest rates or other gains exceeding plan assumptions, we and our affiliates will have to satisfy the underfunded amounts of these plans through cash contributions over time. The timing and amounts of funding requirements depend upon a number of factors, including interest rates, asset returns, potential changes in pension legislation, our decision to make voluntary prepayments, applications for and receipt of waivers to reschedule contributions and changes to pension plan benefits.

The Pension Protection Act was enacted on August 17, 2006. While the Pension Protection Act will have some effect on specific plan provisions in our retirement programs, the primary effect will be to change the minimum funding requirements for plan years beginning in 2008. The Pension Protection Act has directed the United States Department of the Treasury to develop a new yield curve to discount pension obligations for determining the funded status of a plan when calculating funding requirements. Until regulations are issued by the Department of the Treasury, we are unable to determine the effect on our consolidated financial statements; however, such regulations are unlikely to have a material adverse effect on our results of operations.

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

A basic premise of our generation business is that generating power at central facilities achieves economies of scale and produces electricity at a low price. There are other technologies that can produce electricity, most notably fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technology will reduce the cost of alternative methods of electricity production to levels that are equal to or below that of most central station electric production, which could have a material impact on our results of operations.

Terrorist attacks, future war 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 generation facilities or an inability to operate as a result of systemic damage resulting from an act against the transmission and distribution infrastructure that we use to transport our power. If such an attack were to occur, our business, financial condition and results of operations 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 generation industry. We may not have adequate insurance to cover all of these hazards.

Our operations are subject to many hazards associated with the power generation 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, 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.

The subsidiaries that own our generation facilities in New York, including our Lovett and Bowline facilities, have not emerged from Chapter 11.

Our subsidiaries related to our New York business operations, Mirant New York, Mirant Bowline, Mirant Lovett, Hudson Valley Gas and Mirant NY-Gen, remain in bankruptcy. Our Lovett and Bowline generation facilities in New York were subject to disputes with local tax authorities regarding property tax assessments that were not resolved until December 2006. Mirant Lovett is in discussions with the NYSDEC and the New York State Office of the Attorney General regarding environmental controls required under the 2003 Consent Decree for the Lovett generation facility to continue operating past April 30, 2007, for unit 5 and past April 2008, with respect to unit 4. Until a resolution is reached on environmental controls that would permit economically feasible operation, Mirant Lovett will likely remain in Chapter 11. Mirant NY-Gen, which owns hydroelectric facilities at Swinging Bridge, Rio and Mongaup, and small combustion turbine facilities at Hillburn and Shoemaker, is insolvent. Its expenses are being funded under a debtor-in-possession facility provided by Mirant Americas with the approval of, and under the supervision of, the Bankruptcy Court. Mirant NY-Gen is proceeding with the implementation of a remediation plan for the sinkhole discovered in May 2005 in the dam at the Swinging Bridge facility.

On January 26, 2007, the Emerging New York Entities filed the Supplemental Plan with the Bankruptcy Court. For more information on the Supplemental Plan, see Item 3. Legal Proceedings, Chapter 11 Proceedings. The hearing before the Bankruptcy Court to consider the confirmation of the Supplemental Plan is scheduled for March 21, 2007. Until our subsidiaries related to our New York business operations emerge from bankruptcy, we will not have access to the cash from operations generated from these subsidiaries. In 2006, our New York operations generated $17 million of cash from operating activities.

On January 31, 2007, Mirant New York entered into an agreement for the sale of Mirant NY-Gen, which owns the Hillburn and Shoemaker gas turbine facilities and the Swinging Bridge, Rio and Mongaup hydroelectric generating facilities. An auction process supervised by the Bankruptcy Court is required before bankruptcy court approval may occur. The estimated sales price of $3 million is subject to adjustments for working capital and certain dam remediation efforts that are ongoing at the Swinging Bridge facility. The transaction is expected to close in the second quarter of 2007.

We may be subject to claims that were not discharged in the bankruptcy cases, which could have a material adverse effect on our results of operations and profitability.

The nature of our business frequently subjects us to litigation. Substantially all of the material claims against us that arose prior to the bankruptcy filing in July 2003 were resolved during our Chapter 11 proceedings. In addition, the Bankruptcy Code provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation and certain debts arising afterwards. With a few exceptions, all claims that arose prior to our bankruptcy filing and before confirmation of the Plan in December 2005 are (1) subject to compromise and/or treatment under the Plan or (2) discharged, in accordance with the Bankruptcy Code and terms of the Plan. Circumstances in which claims and other obligations that arose prior to our bankruptcy filing were not discharged primarily relate to certain actions by governmental units under police power authority, where we have agreed to preserve a claimant s claims, as well as, potentially, instances where a claimant had inadequate notice of the bankruptcy filing. The ultimate resolution of such claims and other obligations may have a material adverse effect on our results of operations and profitability.

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 vigorously defend 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.

Item 2. *Properties*

The following properties were owned or leased as of December 31, 2006:

Operating Plants:

Power Generation Business	**Location**	**Plant Type**	**Primary Fuel**	**Mirant s % Leasehold/ Ownership Interest(1)**	**Total MW(2)**	**Net Equity Interest/ Lease in Total MW(2)**	**2006 Capacity Factor(3)**
Continuing Operations							
Mid-Atlantic Region:							
Chalk Point	Maryland	Intermediate/Baseload/Peaking	Natural Gas/Coal/Oil	100	2,429	2,429	22 %
Dickerson	Maryland	Baseload/Peaking	Natural Gas/Coal/Oil	100	853	853	42 %
Morgantown	Maryland	Baseload/Peaking	Coal/Oil	100	1,492	1,492	58 %
Potomac River	Virginia	Intermediate/Baseload	Coal	100	482	482	26 %
Total Mid-Atlantic					5,256	5,256	36 %
Northeast Region:							
Canal	Massachusetts	Intermediate	Natural Gas/Oil	100	1,112	1,112	17 %
Kendall	Massachusetts	Baseload	Natural Gas/Oil/Jet fuel	100	256	256	52 %
Martha s Vineyard	Massachusetts	Peaking	Diesel	100	14	14	1 %
Wyman	Maine	Peaking	Fuel Oil	1.4	614	9	
Total New England					1,996	1,391	23 %
Bowline	New York	Intermediate/Peaking	Natural Gas/Oil	100	1,125	1,125	2 %
Hillburn	New York	Baseload/Peaking	Natural Gas/Jet Fuel	100	51	51	
Lovett	New York	Baseload/Peaking	Natural Gas/Coal/Oil	100	411	411	44 %
Mongaup	New York	Intermediate/Peaking	Hydro	100	4	4	23 %
Rio	New York	Intermediate/Peaking	Hydro	100	9	9	34 %
Shoemaker	New York	Peaking	Natural Gas/Jet Fuel	100	44	44	1 %
Swinging Bridge	New York	Intermediate/Peaking	Hydro	100	12	12	8 %
Total New York				100	1,656	1,656	13 %
Total Northeast					3,652	3,047	