MIRANT CORP
Form 10-K
March 14, 2006

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, 2005

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:

Common Stock, par value $0.01 per share

Series A Warrants

Series B Warrants

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. x

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. Large Accelerated Filer x 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 $206,679,075 on June 30, 2005 (based on $0.51 per share, the closing price in the daily composite list for transactions on the Pink Sheets Electronic Quotation Service for that day). As of March 3, 2006, there were 300,000,000 shares of the registrant s Common Stock, $0.01 par value per share outstanding.

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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, you can identify forward-looking statements by terminology such as may, will, should, expect, plan, anticipate, estimate, predict, potential or continue or the negative of these terms or other comparable terminology.

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

- legislative and regulatory initiatives regarding deregulation, regulation or restructuring of the electric utility industry; 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;

- our pursuit of potential business strategies, including the disposition or utilization of assets;

- changes in market conditions, including developments in energy and commodity supply, demand, volume and pricing, 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;

- 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 fuel supply and delivery for our facilities;

- curtailment of operations due to transmission constraints;

- environmental regulations that restrict our ability to operate our business;

- war, terrorist activities or the occurrence of a catastrophic loss;

- 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;

- 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 independent system operators (ISOs) or regional transmission organizations (RTOs) that 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 on terms and prices acceptable to us;

- legislative and regulatory initiatives and changes in the application of laws and regulations by national and local governments in foreign countries where we have operations;

- political factors that affect our international operations, 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 and our inability to access that cash flow to enable us to make debt service and other payments;

- 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 Mid-Atlantic, LLC (Mirant Mid-Atlantic) contained in its leveraged lease financing agreements;

- 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;

- our ability to negotiate favorable terms from suppliers, counterparties and others and to retain customers because we were previously subject to bankruptcy protection; and

- the disposition of the pending litigation described in this Form 10-K.

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

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.

PART I

Item 1. *Business*

Overview

We are an international energy company whose revenues are primarily generated through the production of electricity in the United States, the Philippines and the Caribbean. As of December 31, 2005, we owned or leased approximately 17,500 megawatts (MW) of electric generating capacity.

Mirant Corporation was originally incorporated in Delaware on April 20, 1993. In conjunction with our emergence from Chapter 11 of Title 11 of the United States Bankruptcy Code (as amended, the Bankruptcy Code), our corporate structure changed. As a result, on January 3, 2006, substantially all of the assets of the old Mirant were transferred to a new Delaware corporation which was then renamed Mirant Corporation (New Mirant) and the former company was transferred to a trust. New Mirant serves as the corporate parent of our business enterprise and pursuant to the Plan of Reorganization (the Plan) has no successor liability for any unassumed obligations of the former company.

We manage our business through three principal operating segments: United States, Philippines and Caribbean. Our United States segment consists of the ownership, long-term lease and operation of power generation facilities and energy trading and marketing operations. The Philippine segment includes ownership, long-term lease or similar interests in power generating facilities. The Caribbean segment includes power generation businesses in Curacao and Trinidad and Tobago, and integrated utilities in the Bahamas and Jamaica. The table below summarizes selected financial information for the year ended December 31, 2005, about our business segments (dollars in millions):

	Revenues	%	Gross Margin	%	Operating Income	%	Total Assets
Business Segment:							
United States	$ 2,963	71 %	$ 971	55 %	$ 46	11 %	$ 8,925
Philippines	491	12	464	27	275	66	2,951
Caribbean	730	17	319	18	93	22	1,224
Corporate and Eliminations					4	1	(188)
Total	$ 4,184	100 %	$ 1,754	100 %	$ 418	100 %	$ 12,912

The annual, quarterly and current reports, and any amendments to those reports, that we file with or furnish to the U.S. Securities and Exchange Commission (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. Information contained in our website is not incorporated into this Form 10-K.

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 after January 3, 2006.

Reorganization under Chapter 11 of the Bankruptcy Code

On July 14, 2003 (the Petition Date), and various dates thereafter, Mirant and 83 of its direct and indirect subsidiaries in the United States (collectively, the Mirant Debtors) filed with the United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division (the Bankruptcy Court) voluntary petitions for relief under the Bankruptcy Code, commencing the case *In re Mirant Corporation et al*., Case No. 03-46590 (DML).

Additionally, on the Petition Date, certain of our Canadian subsidiaries, Mirant Canada Energy Marketing, Ltd. and Mirant Canada Marketing Investments, Inc. (together, the Mirant Canadian Subsidiaries), filed an application for creditor protection under the Companies Creditors Arrangement Act in Canada, which, like Chapter 11, allows for reorganization under the protection of the court system. The Mirant Canadian Subsidiaries emerged from creditor protection on May 21, 2004.

Our businesses in the Philippines and the Caribbean were not included in the court-supervised reorganizations.

During the pendency of the Chapter 11 proceedings, the Mirant Debtors operated their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code, the Federal Rules of Bankruptcy Procedure and applicable orders, as well as other applicable laws and rules. In general, each of the Mirant Debtors, as a debtor-in-possession, was authorized under the Bankruptcy Code to continue to operate as an ongoing business, but not to engage in transactions outside the ordinary course of business without the prior approval of the Bankruptcy Court.

On December 9, 2005, the Bankruptcy Court entered an order confirming our Plan, which became effective on January 3, 2006. The Plan set forth the structure of the Mirant Debtors at emergence and outlined how the claims of creditors and stockholders were to be treated. The implementation of the Plan resulted in, among other things, a new capital structure, the discharge of certain indebtedness, the satisfaction or disposition of various types of claims against us, the assumption or rejection of certain contracts and the establishment of a new Board of Directors.

On January 3, 2006, substantially all of the assets of the old Mirant were transferred to New Mirant, which, pursuant to the Plan, has no successor liability for any unassumed obligations of the old Mirant. On January 31, 2006, the trading and marketing business of Mirant Americas Energy Marketing, L.P. (Mirant Americas Energy Marketing), Mirant Americas Development, Inc., Mirant Americas Production Company, Mirant Americas Energy Capital, LLC, Mirant Americas Energy Capital Assets, LLC, Mirant Americas Development Capital, LLC, Mirant Americas Retail Energy Marketing, L.P., and Mirant Americas Gas Marketing, LLC, (collectively, the Trading Debtors) was transferred to Mirant Energy Trading, LLC (Mirant Energy Trading), which, pursuant to the Plan, has no successor liability for any unassumed obligations of the Trading Debtors. After these transfers took place, old Mirant and the Trading Debtors were transferred to a trust created under the Plan.

In connection with the implementation of the Plan, MC Asset Recovery, LLC (MC Asset Recovery) was formed as our wholly-owned subsidiary on December 30, 2005, to prosecute, settle or liquidate certain avoidance actions filed by Mirant during the Chapter 11 proceedings for the benefit of claimants in the bankruptcy proceedings. For further discussion of such actions and MC Asset Recovery, see Note 15 to our consolidated financial statements contained elsewhere in this report.

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 Public Utility Regulatory Policies Act of 1978 (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. Independent system operators (ISOs) and regional transmission organizations (RTOs) were created to administer the new markets and maintain system reliability. Beginning in the fall of 2001, however, in response to extreme price volatility and energy 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 such plants could be constructed more quickly and were less expensive to permit and build than nuclear facilities or plants fired by other fossil fuels. 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 prices of natural gas during 2005. These high natural gas prices have significantly affected electricity prices in markets where gas fired units generally set the price. Some companies are constructing or attempting to obtain permits to construct additional liquefied natural gas receiving facilities which would increase the non-domestic supply of natural gas to the United States and could help to mitigate natural gas prices.

Coal fired generation and nuclear generation account for approximately 50% and 20%, respectively, of the electricity produced in the United States. Current high electricity prices as a result of high natural gas prices have led to renewed interest in new coal fired or nuclear plants. Some regulated utilities are proposing to construct clean coal units or new nuclear plants, in some cases with governmental subsidies or under legislative mandate. These utilities often are able to recover fixed costs through regulated retail rates, including, in many circumstances, the costs of environmental improvements to existing coal facilities, allowing them to build, buy and upgrade without relying on market prices to recover their investments as we must do.

A number of factors combined to create excess generating capacity in certain U.S. markets, including the 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. Although electricity supply and demand spreads have begun to tighten, we do not expect our primary markets to reach target reserve margins, approximately 15% of excess capacity over peak demand, until 2008 to 2010. However, given the time necessary to permit and construct new power plants, we think that certain markets in the United States need to begin now the process of adding generating capacity to meet growing demand. Many ISOs are considering 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.

As a result of recent events, many regulated utilities are seeking to acquire distressed assets or build new generation, 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

Historically, we managed our business as two operating segments: North America and International. In the fourth quarter of 2005, we changed our management structure significantly. As a result, we now manage the following three operating segments: United States, Philippines and Caribbean. Our reportable segments are strategic businesses that are geographically separated and managed independently. For selected financial information about our business segments and information about geographic areas, see

Note 21 to our consolidated financial statements contained elsewhere in this report. See Item 2. Properties for a complete list of our assets.

United States

Overview

In our United States segment, 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 in the United States are ISOs, utilities, municipal systems, aggregators, electric cooperative utilities, producers, generators, marketers and large industrial customers. In the United States, we serve four primary geographic areas: (i) the Mid-Atlantic Region, (ii) the Northeast Region, (iii) the Mid-Continent Region and (iv) the West Region, including Texas.

Ownership and Operations of Electricity Generation Assets

As of December 31, 2005, we owned or leased generation facilities in the United States with an aggregate generation capacity of over 14,000 MW, including 77 MW that were held for sale as of that date. Our domestic 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 included approximately 25% baseload units, 49% intermediate units and 26% peaking units. Mirant Americas Generation, LLC (Mirant Americas Generation), our wholly-owned subsidiary, owns or controls approximately 85% of our U.S. generating capacity.

Commercial Operations

Our commercial operations consist primarily of procuring fuel, dispatching electricity, hedging the production and sale of electricity by our generating facilities, and providing logistical support for the operation of our facilities (by, for example, procuring transportation for coal). We often sell the electricity we produce into the wholesale market at the prices in effect at the time we produce it (spot prices). Those prices are volatile, however, and in order to reduce the risk of that volatility we often enter into hedges forward sales of electricity into the wholesale market and purchases of enough fuel and emissions allowances to allow us to produce and sell the electricity for different periods of time. We procure these hedges in over-the-counter transactions or exchanges where electricity, fuel and emissions allowances are broadly traded, or through specific transactions with a seller, 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 trading), 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, in support of our asset trading, and to take advantage of opportunities that we may see 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 value-at-risk in our proprietary trading activities.

Our commercial operations were conducted historically through Mirant Americas Energy Marketing. As of February 1, 2006, the energy marketing operations of Mirant Americas Energy Marketing are being performed by Mirant Energy Trading. Pursuant to the Plan, we contributed our interest in the trading and marketing operations conducted by Mirant Americas Energy Marketing to Mirant Energy Trading, a subsidiary of Mirant North America, LLC (Mirant North America). Mirant Americas Energy Marketing and its remaining assets and liabilities were then transferred to a trust on January 31, 2006.

Mirant Energy Trading has contracted with our subsidiaries that own generation facilities to procure fuel, dispatch facilities and sell the electricity generated in the wholesale market. Mirant Energy Trading uses dispatch models to make daily decisions regarding the quantity and the price of the power our facilities will generate and sell into the markets. In markets governed by ISOs and RTOs, Mirant Energy Trading bids the energy from our generation facilities into the day-ahead energy market and sells ancillary services through the ISO markets. Mirant Energy Trading works 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. In non-ISO markets, Mirant Energy Trading conducts business through bilateral transactions pursuant to which Mirant Energy Trading provides dispatch schedules to the generation facilities.

We currently economically hedge a substantial portion of our Mid-Atlantic coal fired baseload generation (generation that is dispatched most of the time) and our New England oil fired generation through over-the-counter transactions. However, we generally do not hedge most of our cycling and peaking units (generating facilities that are not dispatched as frequently) due to the limited value we can extract in the marketplace and the high cost of collateral typically required to support these contracts. As of March 3, 2006, we have economically hedged approximately 90%, 60%, 30%, and 30% of our expected Mid-Atlantic coal fired generation for the remainder of 2006, 2007, 2008 and 2009, respectively, and purchased approximately 100%, 80%, 30% and 30% of the expected Mid-Atlantic coal requirements for such periods. Included in such amounts are financial swap transactions entered into by Mirant Mid-Atlantic with a counterparty in January 2006 pursuant to which Mirant Mid-Atlantic economically hedged approximately 80%, 50%, and 50% of its expected on-peak coal fired baseload generation for 2007, 2008 and 2009, respectively. The financial swap transactions are senior unsecured obligations of Mirant Mid-Atlantic and do not require us to post cash collateral either in the form of initial margin or to secure exposure due to changes in power prices. In addition, as of March 3, 2006, we have economically hedged approximately 50% of our expected oil fired generation in New England for the remainder of 2006 and procured approximately 50% of the corresponding expected oil requirements.

While over-the-counter 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 over-the-counter market. Typically, we are able to sell these products at a higher premium than standard products. For certain generation facilities, we have sought to enter into longer-term transactions to provide certainty of cash flows over an extended period. These transactions are typically tolling transactions whereby we receive a fixed capacity payment and, in return, grant an exclusive right for the counterparty to procure the fuel for the generation facility and take title to the power generated. Additionally, we have facilities in our United States business unit operating under long-term contracted capacity and reliability must run (RMR) contracts. At December 31, 2005, our contracted capacity pursuant to these agreements was approximately 3,840 MW with terms expiring through April 2014.

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 is typically purchased under short-term contracts usually linked to a transparent oil index price. For our gas fired units, fuel is typically purchased under short-term contracts with a variety of suppliers on a day-ahead or monthly basis.

Our coal supply primarily comes from both the Central Appalachian and Northern Appalachian coal regions. All of our coal is delivered by rail. We monitor coal supply and delivery logistics carefully, and despite occasional interruptions of scheduled deliveries 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 approximately 5,256 MW: Chalk Point, Morgantown, Dickerson and Potomac River. Our Mid-Atlantic region had a combined 2005 capacity factor of 39%. Our Mid-Atlantic facilities are located in Maryland and Virginia and were acquired from Potomac Electric Power Company (PEPCO) in December 2000. The Chalk Point facility is the largest 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, and 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, 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 Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) market. For a discussion of the PJM market, see Regulatory Environment United States below. In connection with the acquisition of the Mid-Atlantic facilities from PEPCO in 2000, we, through Mirant Americas Energy Marketing, agreed to supply PEPCO its full load requirement in the District of Columbia under a transition power agreement (TPA), which expired in January 2005 (the DC TPA). There was a similar TPA in place to supply PEPCO s load in Maryland, which expired in June 2004 (the Maryland TPA). We also have participated in standard offer service auctions in Maryland and Washington, D.C. Power sales, made either directly through these functions or indirectly through subsequent market transactions that are a result of the auction process, serve as economic hedges for the Mid-Atlantic assets.

In connection with our acquisition of the Mid-Atlantic facilities from PEPCO in 2000, we agreed to purchase from PEPCO all power it received under long-term power purchase agreements (PPAs) with Ohio Edison Company (Ohio Edison), which expired in 2005, and Panda-Brandywine, L.P. (Panda), which expires in 2021. We and PEPCO entered into a contractual arrangement (Back-to-Back Agreement) with respect to PEPCO s agreements with Panda and Ohio Edison under which (1) PEPCO agreed to resell to us all capacity, energy, ancillary services and other benefits to which it is entitled under those agreements and (2) we agreed to pay PEPCO each month all amounts due from PEPCO to Panda or Ohio Edison for the immediately preceding month associated with such capacity, energy, ancillary services and other benefits. Under the Back-to-Back Agreement, we are obligated to purchase power from PEPCO at prices that are typically higher than existing market prices for power in the PJM market.

We are currently in litigation with PEPCO related to the Back-to-Back Agreement. See Item 3 Legal Proceedings for a further discussion.

On August 24, 2005, power production at all five units of the Potomac River generating facility was temporarily halted in response to a directive from the Virginia Department of Environmental Quality (Virginia DEQ). The decision to temporarily shut down the facility arose from findings of a study commissioned under an agreement with the Virginia DEQ to assess the air quality in the area immediately surrounding the facility. The Virginia DEQ s directive was based on results from the study s computer modeling showing that air emissions from the facility have the potential to contribute to localized, modeled exceedances of the health-based national ambient air quality standards (NAAQS) under certain unusual conditions. On August 25, 2005, the District of Columbia Public Service Commission filed an emergency petition and complaint with the Federal Energy Regulatory Commission (FERC) and the Department of Energy (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 exists with respect to a shortage of electric energy, the DOE ordered Mirant Potomac River, LLC (Mirant Potomac River) to generate electricity at the Potomac River generation facility, as requested by PJM, during any period in which one or both of the transmission lines serving the central Washington, D.C. area 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. The DOE required Mirant Potomac River to submit a plan, on or before December 30, 2005, that met this requirement and did not significantly contribute to NAAQS exceedances. The DOE advised that it would consider Mirant Potomac River s plan in consultation with the Environmental Protection Agency (EPA). 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 the rehearing requests further. 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 immediate operation of one baseload unit and two cycling units, making it possible to bring the entire plant into service within approximately 28 hours. We are selling the output of the facility into PJM. The DOE s order expires after September 30, 2006, but we expect we 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 addresses NAAQS issues. The EPA also asserts 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 Federal Clean Air Act (Clean Air Act) compliance status of the Potomac River facility. The facility will not resume normal operations until it can satisfy the requirements of the Virginia DEQ and the EPA with respect to NAAQS, unless, for reliability purposes, it is required to return to operation by a governmental agency having jurisdiction to order its operation. On January 9, 2006, the FERC issued an order directing PJM and PEPCO to file a long-term plan to maintain adequate reliability in the Washington D.C. area and surrounding region and a plan to provide adequate reliability pending implementation of this long-term plan. On February 8, 2006, PJM and PEPCO filed their proposed reliability plans. We are working with the relevant state and federal agencies with the goal of restoring all five units of the facility to normal operation in 2007.

Northeast Region

We own generating facilities in the Northeast region consisting of approximately 3,063 MW of capacity. Our Northeast region had a combined 2005 capacity factor of 34%.The Northeast region is comprised of the New York and New England sub-regions. 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 Utilities, Inc. (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 approximately 1,672 MW of capacity. The Bowline facility is a 1,125 MW dual-fueled (natural gas and oil) facility comprised of one intermediate/peaking unit and one intermediate unit. 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 136 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 have an operational interest in the Grahamsville facility, which has a hydroelectric baseload unit. Our operational interest in the Grahamsville facility was pursuant to a sublease between Orange and Rockland and Mirant NY-Gen, LLC (Mirant NY-Gen), which expired on December 30, 2005. We have executed an interim agreement to extend this arrangement, which will be in effect until the earlier of December 31, 2006, or the end of the month following the month in which we receive regulatory approvals from the FERC and the New York Public Service Commission to transfer the facility to Orange and Rockland, which will transfer the facility to the City of New York. We received approval of the transfer from the FERC on February 27, 2006. A proposed expansion at the Bowline facility to add a natural gas and distillate oil fired unit with a total of 750 MW of generation capacity is currently suspended and we are attempting to extend permits such that we have the option to complete the project. Our New York plants operate in a market operated by the Independent System Operator of New York (NYISO). For a discussion of the NYISO, see Regulatory Environment United States below.

Our current plan is to retire one unit of the Mirant Lovett, LLC (Mirant Lovett) facility in 2007 and the remaining two units in 2008. However, we are exploring ways in which to avoid retiring the facility. In order for the facility to remain viable, we need to accomplish three primary tasks. First, we need agreements with the local taxing authorities to reduce property taxes. Although conditions remain to be met before the agreements are final, all of the taxing authorities have agreed in principle to refunds for past disputed taxes and substantial reductions in property taxes through 2012. Second, we need to reach agreement with the State of New York on amendments to a consent decree entered into on June 11, 2003, to resolve issues related to the new source review (NSR) regulations promulgated under the Clean Air Act (the 2003 Consent Decree), which amendments would address the installation of environmental equipment. Third, as current market conditions do not allow Mirant Lovett to recover the necessary returns to fund the installation of environmental controls required under the 2003 Consent Decree, we will need an agreement with a third party assuring us of enough revenue to justify required capital expenditures. It is our view that the Lovett facility is necessary to the provision of reliable electricity to New York City and other areas within the NYISO.

In May of 2005, a sinkhole was discovered in the dam of our Swinging Bridge facility. Mirant NY-Gen is currently discussing with the FERC appropriate remediation for this sinkhole. We conducted a flood study to determine downstream consequences if the maximum capacity of the reservoirs were exceeded at our New York Swinging Bridge, Rio and Mongaup generation facilities, which may require that Mirant NY-Gen be requested by the FERC to remediate these dams as well. Mirant NY-Gen has initiated discussions with the FERC for surrendering its permits to operate all the hydro electric facilities at Swinging Bridge, Rio and Mongaup, and expects to begin that formal process soon. It is not possible at this point to determine the cost of remediating the dam and surrendering the permits, but such costs may be substantial.

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 approximately 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 capable of producing 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 8.8 MW) in the 614 MW Wyman Unit 4 located on Cousin s Island, Yarmouth, Maine. It 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 New England Power Pool (NEPOOL) bilateral markets and into the markets administered by the Independent System Operator New England (ISO-NE) through Mirant Energy Trading. For a discussion of the NEPOOL and the ISO-NE, see Regulatory Environment United States below. We had made a determination that market fundamentals in NEPOOL did not permit us to operate the Kendall facility on an economical basis as a merchant facility. We therefore 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 a settlement agreement with NSTAR Electric and Gas Corporation (NSTAR) and ISO-NE and filed the settlement, which included the RMR agreement with the FERC. The FERC has approved the RMR agreement and we expect that the agreement will extend at least through the second quarter of 2006.

Mid-Continent Region

Our Mid-Continent generating facilities, with a total capacity of 2,445 MW, are located in the Midwest and Southeast markets. Our Mid-Continent region had a combined 2005 capacity factor of 7%. The Midwest facilities, which include our Sugar Creek and Zeeland facilities, consist of 1,372 MW of generating capacity and are all natural gas fired peaking and/or intermediate units. The Southeast includes two facilities, West Georgia and Shady Hills, with a total capacity of 1,073 MW.

Midwest. The Sugar Creek facility is a combined cycle facility with the capability to produce 535 MW. Located in West Terre Haute, Indiana, the Sugar Creek facility has the physical capability to be interconnected with either the Cinergy or American Electric Power, Inc. (AEP) systems. Cinergy is a member of the Midwest Independent Transmission System Operator (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 facility sells energy into either PJM or MISO (whichever is the best available market). When the unit runs in the PJM clearing markets, it receives a price comparable to the AEP/Dayton Hub.

The Zeeland facility, located in Zeeland, Michigan, is comprised of simple cycle units totaling 307 MW of capacity and a 530 MW combined cycle facility (837 MW of total capacity). The Zeeland facility is interconnected with the International Transmission Company, which is a member of the MISO and operated under the East Central Reliability Coordination Agreement (ECAR) which, as of January 2006, has been merged with the Mid-American Interconnected Network (MAIN) and the Mid-Atlantic Area Council (MAAC) reliability regions and is part of ReliabilityFirst, the North American Electric Reliability Council (NERC) subregion. ReliabilityFirst is the successor organization to the three NERC regional reliability councils: MAAC, ECAR and MAIN.

We have a tolling agreement for the electrical energy output (307 MW, simple cycle) from the Zeeland plant, Units 1A and 1B, which expires on May 31, 2006. The tolling agreement provides for the generation owner to provide electric energy and related services using fuel supplied by the customer or with a pass-through to the customer of actual fuel cost. We receive a monthly capacity payment, a variable operating and maintenance payment on a per megawatt hour (MWh) basis and a start-up payment each time the unit is turned on. Our counterparty provides to the Zeeland plant all the fuel required to operate the contractual portion of the plant. Mirant Zeeland, LLC (Mirant Zeeland) indirectly provides a heat rate and availability guarantee. There are bonus and penalty provisions in the agreement for availability outside allowable limits.

Mirant Zeeland Phase 2 (530 MW combined cycle output) has a tolling contract for 100% of its output through March 2006. The toll is with Mirant Energy Trading, which in turn has an agreement with a counterparty. We receive a monthly capacity payment, variable operations and maintenance payments on a per MWh basis and a start-up payment. There are heat rate and availability guarantees with associated bonuses and penalties for being outside of tolerance bands. The fuel required to operate the facility during the term of the toll is provided to Mirant Zeeland through Mirant Energy Trading s agreement with its counterparty. Mirant Zeeland operates under the MISO market and the ReliabilityFirst subregional reliability council of NERC. We are currently in negotiations to extend the Mirant Zeeland tolling agreements through the end of 2006.

For a discussion of the MISO, see Regulatory Environment United States below.

Southeast. We have two facilities in the Southeast with a total capacity of 1,073 MW. 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 approximately 605 MW and 468 MW, respectively. Currently, there is no ISO in the Southeastern Electric Reliability Council.

West Georgia Generating Company, LLC (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 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 has also 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 2014, begins 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 guarantee and receives bonuses and pays penalties when its performance is outside the guaranteed values.

West Region

Our West region facilities, with a total capacity of 3,474 MW, are primarily gas fired generating facilities located in California, Nevada and Texas. Our West region had a combined 2005 capacity factor of 17%.

California. Our generating facilities in California consist of the Pittsburg, Contra Costa and Potrero facilities, which have generation capacity of 1,311 MW, 674 MW and 362 MW, respectively, for a total capacity of 2,347 MW. The Pittsburg and Contra Costa facilities are intermediate 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 baseload steam boiler from which it generates electricity and three oil fired peaking distillate fueled combustion turbines.

The majority of our California assets are subject to RMR arrangements with the California Independent System Operator (CAISO). These agreements are described further under Regulatory Environment United States below. Our California subsidiaries currently have the largest portfolio of units which operate under RMR arrangements in California, reflecting that the location of these units makes them key to electric system reliability. In September 2005, the CAISO Board approved RMR designations for 2006 that are the same as designations for 2005. Pittsburg Unit 7 and Contra Costa Unit 6 are not subject to an RMR arrangement, and thus function solely as merchant facilities in the CAISO. Mirant Energy Trading either sells the output of Pittsburg Unit 7 and Contra Costa Unit 6 into the market through bilateral transactions with utilities and other merchant generators, or dispatches the units in the CAISO clearing markets.

Pittsburg Unit 7, which has 682 MW of generation capacity, operated pursuant to a tolling agreement with a third party that expired in December 2005. We are currently seeking proposals for a one-, two- or three-year tolling arrangement or resource adequacy capacity sale on both Pittsburg Unit 7 and Contra Costa Unit 6. If we are unable to enter into a new tolling agreement for Pittsburg Unit 7 on acceptable terms, we may retire this unit.

Nevada. The Apex generating facility, a 518 MW intermediate gas fired combined-cycle facility located near Las Vegas, Nevada, was developed by us and began commercial operations in May 2003. 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.

Texas. We have two facilities in Texas, the Bosque facility and the Wichita Falls facility. The Bosque facility consists of a gas fired combustion turbine with a corresponding steam turbine with a capacity of 230 MW that is available to serve baseload and intermediate demand. Additionally, Bosque Units 1 and 2 are gas fired peaking facilities with a capacity of 151 MW each. We have entered into a tolling agreement that grants the counterparty exclusive rights to the power and ancillary services generated by the Bosque facility through December 2006. The Wichita Falls facility is a combined cycle facility and consists of three gas turbines and a steam turbine with a total capacity of 77 MW. The Wichita Falls facility primarily sells its electrical output to the merchant market. On February 13, 2006, we executed an agreement with a third party to sell our 77 MW Wichita Falls facility. The sale is contingent upon finalizing certain closing conditions and is expected to be completed in the second quarter of 2006.

Both the Bosque and Wichita Falls facilities operate in the Electric Reliability Council of Texas (ERCOT) market. For a discussion of ERCOT, see Regulatory Environment United States below.

Philippines

We, indirectly through our Philippine subsidiaries, have ownership, long-term lease or similar interests in eight generating facilities in the Philippines. As of December 31, 2005, our net ownership interest in the generating capacity of these facilities was approximately 2,200 MW. Over 90% of the generation capacity in the Philippine facilities is sold under long-term energy conversion agreements with the Philippine government-owned National Power Corporation (NPC). NPC acts as both the fuel supplier and the energy purchaser under the energy conversion agreements for our Pagbilao, Sual and Ilijan facilities. NPC procures all of the fuel necessary for generation under an energy conversion agreement, at no cost to the respective subsidiary or affiliate, and has substantially all fuel risks and fuel related obligations under the agreement other than those relating to the fuel burning efficiency of the facility.

Under the energy conversion agreements, we receive both fixed capacity fees and variable energy fees. Fixed capacity fees compensate us for our agreement to make the facility available exclusively to NPC and 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 our revenues with respect to our Philippine operations come from fixed capacity charges. Nearly all of our capacity fees 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 Philippine government s build-operate-transfer program. At the end of the term of each energy conversion agreement, the facility is to be transferred to NPC, free from any lien or payment of compensation. The energy conversion agreement for Navotas II, a 95 MW generating facility, expired on July 31, 2005, and the facility was transferred to NPC on August 1, 2005. The energy conversion agreements for the Sual, Pagbilao and Ilijan facilities expire in October 2024, August 2025 and January 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 200 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.

Our larger Philippine projects were granted preferred or pioneer status that, among other things, qualified them for income tax holiday incentives. The income tax holiday incentive expired in June 2002 for our Pagbilao facility and in October 2005 for our Sual facility and will expire in January 2008 for our Ilijan facility. The amount of benefit from these holiday incentives is $45 million, $54 million and $50 million for 2005, 2004 and 2003, respectively.

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 15 to the consolidated financial statements contained elsewhere in this report where further discussed.

Philippine Law Changes

As part of its revenue enhancement program, the Philippine government has enacted certain changes to its existing tax law. The Expanded Value Added Tax (E-VAT) law removes tax exemptions on the sale of electricity, oil products, coal and natural gas, among others, but allows the tax to be passed on to consumers. On January 31, 2006, in accordance with the provisions of the E-VAT, the President of the Philippines raised the value added tax (VAT) rate from 10 percent to 12 percent starting February 1, 2006.

The Supreme Court of the Philippines has upheld the constitutionality of the new VAT law, and the new law became effective on November 1, 2005. There is pending legislation in the Senate and the House of Representatives that seeks to exempt oil and power products from the coverage of the E-VAT to prevent further escalation of oil and electricity prices in the country. It cannot be determined at this point what the prospects are for this legislation being passed.

The E-VAT itself does not have a negative impact on our Philippines operations. This assessment is based on the new tax law s final implementing rules and regulations as prescribed by the Bureau of Internal Revenue that allow us and other independent power producers (IPPs), including the NPC, to pass the VAT on to their consumers. However, the E-VAT does increase corporate income tax rates over the next three years (2006-2008) from 32% to 35%, which may increase the taxes paid by our Philippines operations. Starting in 2009, the corporate income tax rate will decrease to 30%.

Caribbean

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

Jamaica Public Service Company Limited (JPS)

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 for a period of twenty years. 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 (OUR) may waive the requirements for competitive tendering. JPS has installed generation capacity of 603 MW, and it purchases an additional 146 MW of firm capacity from three IPPs 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 555,000 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 indexed to inflation, changes in fuel prices, costs to purchase power and foreign exchange movements. JPS completed its most recent rate case in June 2004.

Grand Bahama Power Company (Grand Bahama Power)

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. In September 2005, a construction expansion of 18 MW was completed. 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, 2005, 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 (PowerGen)

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 the Trinidad and Tobago Electricity Commission (T&TEC), the state-owned transmission and distribution monopoly, 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 the T&TEC, which expires in 2009 and is guaranteed by the government of Trinidad and Tobago. Under this contract, the fuel is provided by the T&TEC.

On November 30, 2004, PowerGen submitted a bid to build new generation and provide electric generation capacity under long-term power purchase agreements to National Energy Corporation (NEC), a government agency responsible for infrastructure development in Trinidad, and T&TEC. On December 6, 2005, PowerGen and T&TEC executed a 30-year 208 MW power sales agreement. PowerGen began construction of the facility in February 2006 and estimates a commercial operations date of February 2007. PowerGen is currently in discussions with NEC and T&TEC to supply approximately 420 MW of additional capacity with a projected commercial operation date during the fourth quarter of 2008.

In January 2006, a new Finance Act was approved by Parliament and the Trinidad and Tobago Senate. The President of Trinidad and Tobago assented to the Finance Act on February 8, 2006. The Finance Act, upon enactment, will change the corporate income tax rate applicable to PowerGen from 30% to 25%.

Curacao Utilities Company (CUC)

We own a 25.5% interest in CUC at the Isla Refinery in Curacao, Netherlands Antilles. The 133 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, 2005, CUC was in technical default under its $97 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. In the event this 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 December preferred dividend because it is in default under its $115 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 has exercised any such options at this time.

At December 31, 2005, Aqualectra was in default under its $115 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. However, Aqualectra is current in its debt service payments under its credit facility and is engaged in discussions with its lenders with respect to its financial situation and pending defaults. An energy fund was established by the Island Council and Executive Council of the Island Territory of Curacao in December 2005 intended to stabilize the prices of the energy related products on the island for the period 2005 through 2006. The energy fund will 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. Aqualectra has recovered approximately $7 million Netherlands Antillean Guilder (ANG) (US $3.9 million) in excess fuel costs from the energy fund for 2005 and expects to recover an additional $5 million ANG (US $2.8 million) in March 2006. Aqualectra also expects to receive a waiver from the banks related to its financial covenant breaches after the receipt of the March payment from the energy fund and to pay our past due December preferred dividend at that time.

Under the terms of the Aqualectra stockholders agreement, we have the right to elect a majority of the members of the supervisory board of Aqualectra and to control the appointment of management and stockholder votes during the pendency of certain triggering events, including (i) a default under indebtedness in excess of $1 million, (ii) a failure to honor our option to require it to purchase our preferred equity interest, (iii) a failure to make two consecutive dividend payments and (iv) a failure to maintain the specified debt service ratio. Although our right to exercise additional control has been triggered, we are continuing to evaluate the situation and, to date, we have not elected to exercise such right.

Regulatory Environment

United States

The U.S. 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 generating facilities 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 sales for resale of natural gas, but does not regulate the prices received by our subsidiary that markets natural gas.

The Energy Policy Act of 2005 (EPAct 2005) became law on August 8, 2005, and it contains a wide range of provisions addressing many aspects of the electric industry. The EPAct 2005 repealed the Public Utility Holding Company Act of 1935 (PUHCA) and enacted the Public Utility Holding Company Act of 2005, which imposes on us additional obligations to maintain books and records unless we qualify for an exemption from these requirements, which is anticipated. The EPAct 2005 requires the FERC and other agencies to engage in numerous rulemakings and we are evaluating the potential impacts and opportunities that may result from these rulemakings. The EPAct 2005 authorizes the FERC to oversee new Electric Reliability Organizations that will develop and enforce national and regional reliability standards. In addition, the EPAct 2005 greatly expands the FERC s ability to impose criminal and civil penalties for violations of the Federal Power Act with a specific emphasis on market manipulation and market transparency.

The FERC has authorized our subsidiaries that constitute public utilities under the Federal Power Act to sell energy and capacity at wholesale market-based rates and has authorized some of these subsidiaries to sell certain ancillary services at wholesale 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 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, it would no longer be able to make certain sales of natural gas.

The majority of our facilities operate in ISO/RTO regions. In areas where ISOs or RTOs control the regional transmission systems, market participants have expanded access to transmission service. ISOs and RTOs also may operate real-time and day-ahead energy and ancillary services markets, which are 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 an 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, the Midwest and California have joined the existing ISO/RTO for their respective region.

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 are 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 has put in place 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.

At the state and local levels, regulatory authorities historically have overseen the distribution and sale of retail electricity 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 at the retail level in a state with a retail access program, it may be subject to state certification requirements and to bidding rules to 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 dispatches generators accordingly. 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 in 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 over the last three years to include Allegheny Power, Commonwealth Edison, AEP, Duquesne Light, Dayton Power & Light (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 will need capacity additions within the next few years.

On August 31, 2005, PJM filed its Reliability Pricing Model (RPM) with the FERC. This proposal is intended to replace its current capacity market rules. The new RPM proposal would provide for establishment of locational deliverability zones for capacity phased in over a several year period beginning on June 1, 2006. If ultimately approved by the FERC in a form not materially different from what was filed, the new RPM would result in increased opportunities for generators to receive more revenues for their capacity. However, on November 5, 2005, PJM proposed to delay the effective date of the RPM until June 1, 2007, and it is impossible to predict whether this or a similar proposal will be adopted.

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 first to 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 employs an Automated Mitigation Procedure (AMP) in its day-ahead market that automatically caps energy bids when certain established bid screens indicate a bidder may have market power. In response to a January 14, 2005, order of the U.S. Court of Appeals for the D.C. Circuit, in the spring of 2005 the NYISO discontinued use of the AMP in the upstate region known as Rest of State. In addition, 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. It is possible that 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, with a price mitigation method similar to the NYISO s AMP (discussed above), although it is implemented via manual processes rather than the automated process employed in New York. In 2004, the FERC approved a locational installed capacity market for ISO-NE (the LICAP proposal) based on the demand curve concept used by the NYISO to be implemented in January 2006. The LICAP proposal included demand curves, which are administrative mechanisms used to establish electricity generation capacity prices. A hearing on the demand curve parameters was held in February and March 2005 and an initial decision was issued by the presiding administrative law judge that found in favor of many of the suppliers issues in the hearing. A subsequent FERC order issued on October 21, 2005, pushed back the LICAP implementation date to no sooner than October 1, 2006, and put in place procedures to pursue a settlement on alternatives to the LICAP mechanism. Any such alternatives were to be submitted to the FERC by January 31, 2006. On January 31, 2006, a FERC settlement judge reported that an agreement in principle had been reached among the majority of parties in the LICAP proceeding and requested an extension of the January 31, 2006 deadline so that a final settlement could be filed with the FERC by March 6, 2006. We cannot predict if a final settlement will be filed with the FERC or if or when the LICAP proposal or any alternative proposal may be implemented or the impact any such proposal may have on our business and results of operations.

Mid-Continent Region. Our Mid-Continent plants are located in the Midwest and Southeast markets. In the Midwest markets, our facilities participate in a market administered by the MISO. The MISO commenced administering energy markets similar to those operated by PJM in the spring of 2005. The MISO uses locational marginal pricing for energy. The MISO proposes to implement a permanent solution to resource adequacy by June 1, 2007, but has not yet identified a specific capacity market design or when it will file a tariff with the FERC. The MISO also implements mitigation rules similar to those of the NYISO, without an automatic mitigation mechanism. Our Sugar Creek facility is interconnected to both the MISO and PJM, through Cinergy s and AEP s transmission systems, and can sell into either market (although not into both simultaneously). Sugar Creek is eligible to participate in the PJM capacity and energy markets.

In the Southeast, we currently sell electric energy and capacity under bilateral contracts that contain terms and conditions that are not standardized and that have been negotiated on an individual basis. Customers in this region include investor-owned, vertically integrated utilities, municipalities and electric cooperatives.

West Region. Our generation facilities in the West are located in the Western Interconnection and ERCOT market in Texas. Our California facilities are located in 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 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.

The CAISO has proposed changes to its market design to more closely mirror the Eastern ISO markets. The market redesign has been delayed several times, with full implementation now expected in 2007 or 2008. The California Public Utilities Commission (CPUC) has taken the lead role for establishing capacity requirements in California and has ordered California s load serving entities to demonstrate, beginning in the summer of 2006, that they have acquired sufficient capacity to serve their forecast retail load plus a specified reserve margin. 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 also 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 or the result of the CPUC proceeding or the timing or development of a wholesale capacity market by either the CPUC or the CAISO.

The majority of our assets in California are subject to RMR arrangements with the CAISO. These agreements require certain of our facilities, under certain conditions and at the CAISO s request, to operate at specified levels in order to support grid reliability. Under the RMR arrangements, we recover through fixed charges either a portion (RMR Contract Condition 1) or all (RMR Contract Condition 2) of the annual fixed revenue requirement of the generation assets as approved by the FERC (the Annual Requirement). Our California generation facilities operating under RMR Contract Condition 1 depend on revenue from sales of the output of the plants at market prices to recover the portion of the plant s fixed costs not recovered through RMR payments.

Our subsidiaries owning facilities subject to the RMR arrangements have entered into two PPAs with Pacific Gas & Electric (PG&E) that allow PG&E to dispatch and purchase the power output of all units of those generation facilities designated by the CAISO as RMR units under the RMR arrangements. The first agreement was in effect during 2005 and the second agreement extends from 2006 through 2012. Under those agreements, those units designated as RMR by the CAISO are designated as RMR Contract Condition 1, but during 2005 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 on an aggregate basis from those 2004 rates by $5 million. After 2008, we will file annually for FERC approval of the Annual Requirement, which, once approved by the FERC, will set the rates to be charged.

The CAISO imposed a $400 per MWh hour cap, effective on January 1, 2006, on prices for energy and has implemented an AMP similar to that used by the NYISO. 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 must-offer requirement). The practical effect of this rule is to obtain operating reserves without paying for them, and to release excess supply energy into the market, thus depressing prices. On August 26, 2005, the Independent Energy

Producers, a trade association, filed a complaint at 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. If granted by the FERC, the new RCST may result in increased capacity revenue opportunities for generators.

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 logbook standards for electricity generating facilities. In its orders, the CPUC has stated its intent to implement and enforce these detailed standards so as 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 logbook 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.

Our Texas plants participate in a market administered by ERCOT, which manages a major portion of the state s electric power grid. ERCOT oversees competitive wholesale and retail markets resulting from electricity restructuring in Texas and protects the overall reliability of the ERCOT grid. ERCOT, the only ISO that manages both wholesale and retail market operations, is regulated by the Public Utility Commission of Texas (PUCT). The PUCT conducts market monitoring within ERCOT. Price mitigation measures in ERCOT include a $1,000 per MWh price cap and RMR-type contracts for congested areas. The PUCT has recently conducted hearings on wholesale market design issues that will focus on adding a congestion management mechanism based on locational pricing, using nodal locational pricing with day-ahead and real-time markets. Presently, we cannot estimate when the enhancements will be completed and implemented.

Philippines

In June 2001, the Philippine Congress approved and passed into law the Electric Power Industry Reform Act (EPIRA), providing the mandate and the framework to introduce competition in the Philippine electricity market. EPIRA also provides for the privatization of the assets of NPC, including its generation and transmission assets, as well as its contracts with IPPs. The deregulation of the Philippine electricity industry and the privatization of NPC have been long anticipated, and EPIRA is not expected to have a material impact on our existing Philippine assets or our operations. EPIRA provides that competition in the retail supply of electricity and open access to the transmission and distribution systems was to have occurred within three years from EPIRA s effective date in June 2001. Prior to June 2002, concerned government agencies were to establish a wholesale electricity spot market, ensure the unbundling of transmission and distribution wheeling rates and remove existing cross-subsidies provided by industrial and commercial users to residential customers.

In August 2005, the Energy Regulatory Commission (ERC) of the Philippines issued a resolution reiterating the statutory mandate under the EPIRA law for generation companies to make a public offering of at least 15% of their common shares by June 2006. The ERC has not yet issued rules and regulations regarding this requirement and they are not expected to in time to allow this requirement to be met by June 2006. As a result, the ultimate impact cannot be determined.

Under EPIRA, NPC s generation assets are to be sold through transparent, competitive public bidding, while all transmission assets are to be transferred to the Transmission Company, initially a government-owned entity that is to eventually be privatized. The privatization of these NPC assets has been delayed and is considerably behind the schedule set by the Philippine Department of Energy. EPIRA also created the Power Sector Assets and Liabilities Management Corporation (PSALM), which is to accept transfers of all assets and assume all outstanding obligations of NPC, including its obligations to IPPs. One of PSALM s responsibilities is to manage these contracts with IPPs after NPC s privatization. PSALM also is responsible for privatizing at least 70% of the transferred generating assets and IPP contracts no later than three years from the effective date of the law. The work related to the planned privatization has commenced, but is considerably behind schedule.

Consistent with the announced policy of the Philippine government, EPIRA contemplates continued payment of NPC s obligations under its energy conversion agreements. The energy conversion agreements of our Philippine subsidiaries with NPC are not assignable without our consent. We are continuing discussions with NPC and PSALM on a proposal to add PSALM as an additional obligor under NPC s existing energy conversion agreements. Additionally, the Philippine government issued performance undertakings to guarantee the performance of NPC s obligations under certain energy conversion agreements.

There is new proposed legislation in the Philippines Senate that seeks to introduce changes and amendments to the EPIRA. Mirant Philippines energy conversion agreements with NPC provide change in law protection and the Republic of the Philippines has issued performance undertakings to guarantee performance of the NPC s obligations under its energy conversion agreements.

While it is our view that we have adequate contractual rights and governmental assurances to prevent any adverse financial impact to operations resulting from any amendments to EPIRA, the ultimate effect cannot be determined at this time.

Caribbean

Jamaica

Regulatory Environment. The principal activities of JPS are regulated in accordance with the terms of the License. The OUR, which was established pursuant to the Office of Utility Regulation Act of 1995, was granted authority to regulate the rates charged by JPS and its performance under the License.

All-Island Electric License. JPS operates pursuant to a 20-year License that grants it the exclusive right to transmit, distribute and supply electricity on the island of Jamaica. Upon expiration of the initial term of the License, and at the expiration of any extension, the government of Jamaica may acquire JPS s business at its fair market value, as determined by an independent valuation expert. The government of Jamaica is required to give JPS two years prior notice of its intent to acquire the business and if no such notice is given, the License will continue in force for successive ten-year terms.

If JPS fails, without just cause or excuse, to comply with any material term or condition of the License, fails to carry out with good faith or reasonable diligence its obligation under the License, or is financially impaired in its ability to perform under the License, the government of Jamaica may revoke the License and acquire JPS s business at 75% of its fair market value. Additionally, the government of Jamaica has certain step-in rights to enter and operate the electric undertaking, according to prudent utility practice, if JPS fails to operate a substantial part of its system and/or any generation facility for 48 consecutive hours without just cause.

Tariff Structure. Schedule 3 of the License defines the rates for electricity and the mechanism for rate adjustments. Under the License, the rates for electricity consist of a non-fuel base rate, which is adjusted annually for inflation and certain performance measures and a fuel rate, which is adjusted monthly to reflect fluctuations in actual fuel costs, net of adjustments for prescribed efficiency targets.

Both rates (fuel and non-fuel) are adjusted monthly to account for movements in the monetary exchange rate between the U.S. dollar and the Jamaican dollar.

These rates are determined in accordance with the tariff regime, provided that the OUR annually reviews the company s efficiency levels (system losses and heat rate) and, where appropriate, adjusts these in the tariff, primarily as it relates to fuel revenues. Under the rate schedule the Company should recover its actual fuel costs net of the prescribed efficiency adjustments through its fuel rate.

Beginning May 31, 2004, and each fifth year thereafter, JPS filed and will file with the OUR to obtain adjustment to its non-fuel base rate. The rate filing, which requires OUR approval, is based on a test year and takes into account efficient non-fuel operating costs, depreciation expenses, taxes, and a fair return on investment.

The OUR approved a non-fuel base rate, which became effective on July 1, 2004 and includes an embedded amount designed to allow JPS to establish a reserve against damage caused by major catastrophes of $2 million annually. The amounts that JPS sets aside each month as restricted cash under this provision are the product of this embedded rate multiplied by the actual energy sales.

Bahamas

Regulatory Environment. In 1955, the Grand Bahama government granted 639 square kilometers of the island of Grand Bahama (the Port Area) to the Grand Bahama Port Authority (the Port Authority). This grant is known as the Hawksbill Creek Agreement and has a term of 99 years. The agreement grants the Port Authority licensing and regulatory functions. Also, in accordance with the Hawksbill Creek Agreement, Grand Bahama Power Company has been granted sole right to generate and supply electric energy to the island of Grand Bahama.

The license agreement between the Port Authority and us dated April 30, 1993, says that the Port Authority will grant any reasonable request of the Company to adjust electric rates in the Port Area. Generally a request for rate increase will be granted if the increase does not exceed increases in the Consumer Price Index, the rate does not exceed the highest rate charged by other providers in the Bahamas for comparable service, and the increase is needed to recover costs due to a change in law or to provide an appropriate return for capital improvements. Approximately 85% of our customer base is in the Port Area.

In 1993, Grand Bahama Power Company entered into agreements to provide electricity to the east and west ends of Grand Bahama Island outside the Port Area. The agreement gave the Port Authority the right to adjust rates and that these rates would not exceed the rates in the Port Area. Approximately 15% of our customer base is outside the Port Area.

Tariff Structure. The Company has three major tariff categories: residential, commercial and industrial. The rates have a base component that is fixed in the tariff proceeding and a fuel surcharge component. The fuel surcharge on monthly bills is proportionately increased or decreased when the cost of fuel consumed at the Company s power plants exceeds or is less than $20 per U.S. barrel. The objective of this fuel adjustment clause is to create a pass-through of increases or decreases in the commodity price of fuel, whether captured in the $20 per barrel base or in the surcharge/rebate. Through the base component of the tariff, the Company retains the risks and benefits from variances in the heat rate.

Environmental Regulation

United States

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 operating permits. Our costs of complying with environmental laws, regulations and permits are substantial. For example, we estimate that our capital expenditures for environmental compliance will be approximately $300 million for 2006 and will be $1 billion to $1.5 billion from 2006 through 2011. Our potential capital expenditures for environmental regulation are difficult to estimate because we cannot now assess what regulations may be applicable or what costs might be associated with certain regulations. Our capital expenditures will be materially impacted if the State of Maryland passes legislation or imposes regulations that increase beyond applicable federal law the restrictions on emissions of sulfur dioxide (SO2), nitrogen oxide (NOx) and mercury, or imposes restrictions on emissions of carbon dioxide (CO2). This legislation or regulation, or similar legislation or regulations in other states or by the federal government, may render some of our units uneconomic.

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.

Acid rain program. The EPA promulgated regulations that establish cap and trade programs for SO2 emissions (the Acid Rain Program) from electric generating units in the United States. Under this system, the Acid Rain Program set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO2 allowance allocations to utilities. Each allowance permits a unit to emit one ton of SO2 during or after a specified year. Affected utility units were allocated allowances based on their historic fuel consumption and a specific emissions rate. Allowances may be bought, sold or banked. Some of our facilities have surplus allowances, and some are required to purchase additional SO2 allowances to cover their emissions and maintain compliance. The costs of SO2 allowances have increased substantially in recent years. Prior to 2004, prices generally ranged between $100 and $200 per ton. Prices rose from approximately $200 per ton to approximately $800 per ton during 2004 and to approximately $1,600 per ton in 2005. We expect to be a net purchaser of allowances for 2006. Many factors can affect the price of SO2 allowances, and we cannot be certain that the price of allowances will not increase substantially from current historical highs in future years. Depending on the actual price and number of SO2 allowances we need to buy, such costs may materially impact us. This program and other regulations requiring further reductions in SO2 emissions, such as the Clean Air Interstate Rule (CAIR) may result in our deciding to further reduce emissions at some of our facilities through new control technology. The cost of additional pollution control technology could be significant; however, it could be partially offset by the avoided cost of purchasing SO2 allowances. For additional discussion of SO2 control technology see the discussion of the CAIR below.

NOx SIP call. New NOx regulations will require a combination of capital expenditures and the purchase of emissions allowances in the future. The EPA has promulgated regulations that established emissions cap and trade programs for NOx emissions from electric generating units in most of the eastern states (the NOx SIP Call). These programs were implemented beginning May 2003 in the Northeast and May 2004 in the rest of the Eastern United States. Under these regulations, a facility receives an allocation of NOx emissions allowances. If a facility exceeds its allocated allowances, the facility must purchase additional allowances. Some of our facilities in these states have been required to purchase NOx allowances to cover emissions to maintain compliance. The cost of allowances will fluctuate in future years, and depending on the actual price and number of NOx allowances we need to buy, such costs could materially affect our operations. As a result, we may decide to reduce NOx emissions through control

technology in addition to what is already installed or planned. The cost of additional pollution control technology could be significant; however, it may be partially offset by the avoided cost of purchasing NOx allowances to operate the facility.

CAIR. In March 2005, the EPA issued the CAIR, which establishes in the Eastern United States a more stringent SO2 cap and allowance-trading program and a year round NOx cap and allowance-trading program applicable to generation facilities. These cap and trade programs would 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. Currently, we are planning to install pollution control equipment at 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 2006 through 2011. 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 over the coming years.

CAMR. The EPA promulgated the Clean Air Mercury Rule (CAMR) on March 15, 2005, which utilizes a market-based cap and trade approach under Section 111 of the Clean Air Act. It requires emissions reductions in two phases, with the first phase going into effect in 2010 and the more stringent cap going into effect in 2018. It is our view that the pollution control equipment we intend to install to comply with the CAIR should adequately reduce mercury emissions to the levels required by 2010. We cannot currently estimate the costs to comply with the reductions required by 2018, but they may be material. The CAMR has faced considerable political and legal opposition, as a result of which the EPA in October 2005 issued a notice of proposed rulemaking to reconsider certain aspects of the CAMR. The CAMR is currently being challenged in federal court. Those challenges may lead to amendments to the CAMR or passage of different mercury control legislation, which could require stricter control of mercury emissions and/or more expensive control equipment.

NSR enforcement initiative. In 1999, the Department of Justice (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 costs. These enforcement actions were broadly challenged by the industry in the courts and the EPA. We have complied with the NSR regulations as they have been interpreted in final, binding decisions. In 2001 the EPA requested information concerning some of our facilities covering a time period that predates our ownership or leasing. The challenges to the new interpretation of the NSR regulations may affect the enforcement actions, but there is no assurance that there will not be further requests or enforcement proceedings that can materially affect our 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.

For example, the Commonwealth of Massachusetts has finalized regulations to further reduce NOx and SO2 emissions from certain generation facilities and to regulate CO2 and mercury emissions for the first time. Mercury emissions reductions will be required exclusively from coal fired facilities. Portions of these regulations, which become effective in the 2005-2008 time frame, will apply to our oil fired Canal

facility in the state, will increase our operating costs and will likely necessitate the installation of additional emissions control technology.

Another example of state regulation that affects our generation facilities arises in the San Francisco Bay area, where we own generation facilities. Regional NOx emissions standards have become increasingly stringent on a specified schedule over a several year period, culminating in 2005. We continued to apply our NOx implementation plan for these facilities, which included the installation of selective catalytic reduction (SCR) emissions control equipment at our Potrero Unit 3 facility and the partial curtailment of two of our higher NOx emitting units.

In 2000, the State of New York issued a notice of violation (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, Inc. (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: (1) emissions controls consisting of SCR technology to reduce NOx emissions; (2) alkaline in-duct injection technology to reduce SO2 emissions; and (3) 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 2005-2008 timeframe. We have recognized that the 2003 Consent Decree and the new regulations, taken together with property taxes based on assessed values for our New York facilities that are far in excess of actual values and with NYISO rules that do not take into consideration the importance of the Mirant Lovett facility to the reliable supply of electricity, would have rendered the continuing operation of the Mirant Lovett facility uneconomic. It is therefore our current plan to retire the Lovett generating facility by 2008. In an effort to keep the plant operating, we are trying to negotiate agreements to reduce property taxes and to compensate Mirant Lovett for its contribution to the reliability of the electricity system, which will enable us to agree with the State of New York to make capital expenditures on environmental controls in excess of $200 million, significantly more than contemplated by the 2003 Consent Decree. The 2003 Consent Decree required Mirant Lovett to notify the state of its selected option by August 1, 2004, which date was extended by the State of New York to August 1, 2005, with subsequent extensions to February 15, 2006. On February 15, 2006, Mirant Lovett submitted a proposal to the State of New York for the installation of certain environmental controls in excess of those in the 2003 Consent Decree conditioned on execution and approval of acceptable property tax and reliability agreements. Pursuant to the Bankruptcy Court s order approving of the 2003 Consent Decree, Mirant Lovett may not enter into a binding agreement to construct the environmental controls or to elect a shutdown of the facility without first obtaining the approval of the Bankruptcy Court.

Climate change. Concern over climate change deemed by many to be induced by rising levels of greenhouse gases in the atmosphere 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 CO_2 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 (see discussion of the Regional Greenhouse Gas Initiative 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 December 20, 2005, seven states in the Northeast agreed to go forward with the implementation of a cooperative known as the Regional Greenhouse Gas Initiative (RGGI). This is the first 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 will be followed by a 10% reduction in emissions by 2019.

This initiative envisions participating states executing a memorandum of understanding and then promulgating implementing regulations based on the RGGI template. The recommended allocation scheme calls for allocation of 20% of allowances to a public benefit purpose and 5% to a regional strategic carbon fund, thereby further reducing allowances available to affected facilities. In the future, the RGGI may include other sources of greenhouse gas emissions and greenhouse gases other than CO_2. If the RGGI results in mandatory regulations in states where we have generating units, our costs of implementation may be material. New York, where we have generating units, is a participant in the RGGI. Massachusetts, where we also have generating units, originally agreed to participate but later withdrew.

On June 1, 2005, the Governor of California established greenhouse gas reduction targets for California, which would by 2010, reduce statewide greenhouse gas emissions to 2000 emissions levels; by 2020, reduce statewide greenhouse gas emissions to 1990 emissions levels; and by 2050, reduce statewide greenhouse gas emissions to 80% below 1990 levels. Implementing strategies to reach these targets will be the responsibility of a Climate Action Team, an interagency team established by the Governor. The team is led by the California EPA and is composed of high level representatives from key state agencies. This team will report to the Governor and the Legislature in early 2006.

Proposed Maryland clean power rule and other air legislative and regulatory developments. In addition to the implementation of existing requirements, there are additional environmental requirements under consideration by the federal and various state legislatures and environmental regulatory bodies. Maryland s governor announced in November 2005 that he intends to propose a Maryland Clean Power Rule, that would require deep reductions in NOx emissions (69% reduction) by the year 2009, and in SO_2 emissions (85% reduction) and mercury emissions (70% reduction) by the year 2010, at six Maryland coal fired generation facilities, including our Chalk Point, Dickerson and Morgantown facilities. If the rulemaking proceeds according to the timing indicated by the Governor s office, that regulation would become effective in the summer of 2006. Although we have not fully evaluated the impacts of the Governor s proposed rule as announced, if adopted, it would limit our ability to acquire emissions allowances for use associated with our Maryland power facilities, and would require us to consider the economic impact of increasing substantially our capital expenditures from 2006 through 2010, which may have a material impact on us. The Governor s rule, which does not require legislative approval, is expected to be officially proposed in the first quarter of 2006 and to be the subject of administrative hearings in the early spring of 2006.

In addition to the proposed state regulations, the Maryland Legislature is in the process of moving the Health Air Act in both the Senate (SB 154) and in the House (HB 189). The House and Senate bills were introduced simultaneously on January 19, 2006. The legislation is similar to the Maryland Clean

Power Rule; however, it would require deeper reductions in NOx and SO2 in 2010 and 2015. It also requires reductions of mercury emissions by the year 2010. More importantly, unlike the Maryland Clean Power Rule, the legislation also includes mandatory reductions of CO2 emissions by 2018. The reductions would be required at all three of our Maryland coal fired generation facilities. There is currently no technology that would meet the proposed requirements for mercury and CO2, and we would have to consider running the facilities less in order to comply.

In addition to the state activities, at the federal level, the Bush Administration has submitted to Congress Clean Air Act multi-emissions reform legislation, which would promulgate a new emissions cap and trade program for NOx, SO2 and mercury emissions from generation facilities. This legislation would require generation facilities to reduce overall emissions of these pollutants by approximately 50-75% phased in during the 2008-2018 timeframe, which is similar to the types of overall reductions required under CAIR and CAMR. More stringent multi-emissions reform legislation also has been proposed in Congress by some lawmakers. If enacted as proposed, some of this legislation may materially impact us.

The EPA and the states are also in the process of implementing new, more stringent ozone and particulate matter ambient air quality standards, and the EPA s rules addressing regional haze visibility issues. The full implementation of any of these rules may result in further emissions reduction requirements for some of our facilities.

Water regulations. We are required under the Federal Water Pollution Control Act (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. It is our view that the regulations recently promulgated by the EPA to implement Section 316(b) of the Clean Water Act, will require us to incur substantial expenses in future years. These regulations address the need to require the best technology available for cooling water intake structures to minimize adverse effects on fish and shellfish. These regulations set performance standards for all existing large power plants and are intended to reduce the losses of aquatic organisms inadvertently pulled into a power plant s circulating water system. Potential compliance alternatives include using existing technologies, selecting additional fish protection technologies and using restoration measures. Over the next few years, our generation facilities subject to this cooling water intake regulation (Bowline, Canal, Kendall, Pittsburg, Contra Costa, Potrero, Chalk Point, Morgantown, Potomac River and Dickerson) will be evaluating and implementing the requirements of the 316(b) regulation by completing impingement and entrainment studies, evaluating technologies, operational measures and restoration measures. The cost of performing the studies and capital expenditures to install barriers or control devices or to implement other protective measures at three of our facilities is expected to approximate $10 million from 2006 through 2011. The cost of installing protection technologies may be material.

In early 2006, the U.S. Department of the Interior, through its Fish and Wildlife Services division (the FWS), sent a letter to the U.S. Army Corps of Engineers requesting that it reinitiate formal consultation on the biological opinion that permits Mirant Delta, LLC (Mirant Delta) to use and recycle water from the San Joaquin river for its operation of the Pittsburg and Contra Costa power plants. The formal consultation process explores the environmental impacts of Mirant Delta s water usage, including the impacts on certain species of fish in the river, and then provides directives regarding the manner in which Mirant Delta may utilize river water for cooling in the plants operations. It is our view that Mirant Delta is operating in compliance with its water usage permits and that this reopening of the formal consultation process is improper. Mirant Delta responded to the FWS, asserting that it has implemented all investigative and operational measures prescribed by the FWS to reduce the impact of its water usage on the endangered species in the San Joaquin River, and it is currently waiting for a response from the FWS to this communication.

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 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, the Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (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 to remediate any groundwater or solid contamination identified by PG&E at the Pittsburg and Contra Costa generating facilities. To date, we have requested that PG&E dispose of 807 cubic yards of contaminated soil at the Potrero generating facility and they have performed such disposal. We are not aware of soil or groundwater conditions that are not covered by third party agreements or insurance policies for which we expect our remediation costs to be material.

Philippines and Caribbean

Most of our international operations are subject to comprehensive environmental regulations similar to those in the United States, and these regulations are expected to become more stringent in the future. Additionally, countries in which our subsidiaries have operations are developing increased environmental regulation of many industrial activities, including increased regulation of air quality, water quality, noise and solid waste management. These developments are discussed below.

Bahamas. In 2005, the Bahamas Environment Science and Technology Commission published draft environmental management legislation and draft final regulations for pollution control and waste management. The draft regulations control air emissions, water discharges and waste management. Prior to implementation, the draft regulations must undergo review and action by the Bahamian Parliament.

Curacao. A regulatory framework for environmental control exists in Curacao and is implemented by the Environmental Service Curacao (ESC). These regulations are implemented through the issuance of nuisance licenses to sources of pollution. The nuisance licenses regulate air emissions, water discharges, waste management and other aspects of our operations. In 2005, the ESC formed an environmental task force consisting of the ESC and local industry. Among the recommendations of the task force were certain regulatory changes, which would be subject to parliamentary action.

Jamaica. Jamaica has an established regulatory framework for environmental control administered by the National Environment and Planning Agency (NEPA). These rules cover air emissions, wastewater discharges, waste management and noise. In 2002, revisions to the air quality regulations were drafted. The draft rules require parliamentary action in order to become effective. In 2006, the NEPA issued draft regulations for wastewater and sludge disposal. These rules, once enacted, will set limits for wastewater discharges at our power plants. The draft regulations will require parliamentary approval in order to become effective.

Philippines. The Philippines has an established environmental regulatory structure administered by the Department of Environment and Natural Resources (DENR). Rules govern air emissions, water discharges, waste management, wildlife management and other aspects of our operations. The DENR implements modifications to the regulations periodically in the form of Departmental Administrative Orders (DAOs). For example, in 2005, 26 DAOs were issued.

Panay Power Corp, a subsidiary of Mirant Global Corporation, a joint venture of which Mirant (Philippines) Corporation owns 50%, did not operate flue gas desulfurizers (FGDs) and emissions monitors in 2003, 2004 and 2005 at two plants. Panay Power considers that its decision not to operate FGDs and emissions monitors was appropriate and it has received no notice of violation. However, this failure may be deemed to be a violation of Administrative Order 2001-81 of the Philippines Department of Energy and Natural Resources, which could result in a significant fine. The FGDs at the plants are now operational and Panay Power is in compliance with applicable SO_2 emissions requirements.

Trinidad. Trinidad and Tobago have an established environmental regulatory structure administered by the Environmental Management Agency (EMA). The current rules require an environmental impact assessment (EIA) of proposed development projects. Upon completion of the EIA, the EMA issues a Certificate of Environmental Clearance that places environmental limitations on the proposed project. The EMA has drafted rules controlling air emissions and water discharges. These rules require parliamentary action in order to become effective.

Over the past several years, federal, state and foreign governments and international organizations have debated the issue of global climate change and policies regarding the regulation of greenhouse gases, one of which is CO_2 emitted from the combustion of fossil fuels by sources such as vehicles and power plants. The European Union and certain developed countries ratified the Kyoto Protocol, an international treaty regulating greenhouse gases, and it became effective in 2005. None of the countries in which we or our subsidiaries presently own or operate power plants has any binding obligations under the treaty. We cannot provide assurances that such laws or regulations will not be enacted in the future in a state or country in which we own or operate power plants, and in such event the impact on our business would be uncertain but could be material.

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Employees

At December 31, 2005, our corporate offices and majority owned or controlled subsidiaries employed approximately 4,550 people. This number includes approximately 540 employees in the corporate headquarters in Atlanta, approximately 1,290 employees at operating facilities in the United States, approximately 1,190 employees in the Philippines and approximately 1,530 employees in our Caribbean operations. The following details the employees subject to collective bargaining agreements:

Union	Location	Number of Employees Covered	Contract Expiration Date
International Brotherhood of Electrical Workers (IBEW) Local 1900	Maryland and Virginia	476	6/1/2010
IBEW Local 503	New York	140	6/1/2008
IBEW Local 1245	California	132	10/31/2008
IBEW Local 396	Nevada	17	7/28/2008
Utility Workers Union of America (UWUA) Local 369	Cambridge, Massachusetts	32	2/28/2009
UWUA Local 480	Sandwich, Massachusetts	51	5/31/2006
United Steel Workers Local 12502	Indiana and Michigan	27	1/1/2007
Bahamas Industrial Engineers, Managerial, and Supervisory Union(1)	Grand Bahama	33	1/1/2005
Commonwealth Electrical Workers Union(2)	Grand Bahama	134	3/31/2005
Jamaica Public Service Managers Association(3)	Jamaica	181	11/30/2004
Union of Clerical Administrative & Supervisory Employees; National Workers Union; Bustamante Industrial Trade Union(3)	Jamaica	1,123	12/31/2004

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

(2) Negotiations are ongoing and will continue into 2006. Overall, the industrial climate is stable.

(3) Negotiations are ongoing with all unions and will continue into 2006. Overall, the industrial climate is stable.

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. Additionally, if our non-unionized workforce moved toward unionization, we could be materially impacted 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 purchase 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 or on a short-term fixed price basis 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. 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 impacted 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 increased 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 which 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.

Changes in commodity prices may negatively impact 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 impact 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 hedging 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 impact 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 known 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 related 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.

Our facilities in the Philippines are exposed to significant risks as a result of their reliance on their contracts with NPC, which purchases almost all of the power generated by those facilities. These risks include political instability, changes in governmental leadership, regulation of the electricity business and the credit quality of the Philippine government. If NPC were to fail to perform its obligations under its energy conversion agreements with us, the resulting loss of cash flow and revenue would have a material adverse affect on our financial condition and results of operations.

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 impact our cash flows and results of operations, including cash flows available to us to make payments on our debt or our other obligations.

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For example, on December 16, 2005, one of the generating units at our Chalk Point facility experienced a forced outage as a result of a structural failure in one of its retired-in-place precipitators. The failure caused damage to associated ductwork. The Chalk Point facility resumed normal operations on January 17, 2006. On September 18, 2005, Unit No. 1 at the Morgantown facility experienced a forced outage in response to high turbine vibration resulting from the failure of one low pressure turbine blade. This failure required the unit to be shut down. The unit returned to service on November 18, 2005.

The accounting for our asset hedging and proprietary trading activities may increase the volatility of our quarterly and annual financial results.

We engage in asset hedging activities in order to economically hedge our exposure to market risk with respect to (1) electricity sales from our generation facilities, (2) fuel utilized by those facilities and (3) emissions allowances. We generally attempt to balance our fixed-price physical and financial 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 activities, through which we attempt to achieve incremental returns by transacting where we have specific market expertise. The derivatives from our asset hedging and proprietary trading activities are recorded on our balance sheet at fair value pursuant to Statement of Financial Accounting Standards Board (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, (SFAS No. 133). These derivatives are not 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 electricity and fuel prices. For example, for the year ended December 31, 2005, we were required to mark-to-market contracts resulting in a $17 million charge as compared to the year ended December 31, 2004, when we were required to mark-to-market contracts resulting in a $148 million gain. For a more detailed discussion of the accounting treatment of our asset hedging and proprietary trading activities, see Note 6 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 impact 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 the Company 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 regulation by federal, state and local authorities, which, among other things, restricts the discharge of pollutants into the air, water and soil, and also governs 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. For example, we currently intend to retire our Lovett generation facility in New York, in part because of substantial environmental capital expenditure requirements, starting with Unit 5 in 2007 and Units 3 and 4 in 2008. We are pursuing alternatives that would make it economically feasible for this generation facility to remain in operation, but there can be no assurances that we will be successful. Furthermore, we had planned to shut down, at least temporarily, the Kendall facility from January 2006 through December 2007, with the possibility of restarting operations in January 2008. However, the ISO-NE determined that a small part of the capacity of the Kendall facility is needed for reliability and negotiated an RMR arrangement for the facility. We may mothball the Kendall facility following the expiration of the RMR arrangement if it is not economically feasible to continue to operate the facility.

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 November 2005, Maryland s governor announced that he intends to propose a Maryland Clean Power Rule that would require deep reductions in NOx emissions by 2009 and in SO2 and mercury emissions by 2010 at six Maryland coal fired power facilities, including our Chalk Point, Dickerson and Morgantown facilities. If the rulemaking proceeds according to the timing indicated by the Governor s office, that rule would become law in the summer of 2006. Although we have not fully evaluated the impacts of the Governor s proposed rule as announced, if adopted as proposed, it would require us to increase substantially our capital expenditure requirements from 2006 through 2010 in a way that could materially and adversely affect us. We may not be able to recover incremental capital costs of compliance with new environmental regulations, which may adversely affect our financial performance and condition.

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.

The expected decommissioning and/or site remediation obligations of certain of our generation facilities may negatively impact 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 impact our cash flows and may adversely impact 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, 2005, our total indebtedness was approximately $3.7 billion. In addition, the present value of lease payments under the Mirant Mid-Atlantic leveraged leases is approximately $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 other 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.

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 credits and other inputs required to produce such power by entering into hedging transactions. These asset hedging activities generally require us to post a significant amount of collateral either in the form of cash or letters of credit. As of December 31, 2005, we had approximately $987 million of posted cash collateral and $58 million of letters of credit outstanding primarily to support our asset hedging 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.

In our efforts to hedge commodity price risk, 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 impact 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 the generation facilities. The majority of our generation is sold at market prices under the 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 impact 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. This has depressed the prices that can be charged for capacity in PJM.

Certain of our assets are located in the ERCOT market. Such assets are not generally subject to regulation by the FERC, but are subject to similar types of regulation by the PUCT.

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 our competitors. Many regulations that could be issued pursuant to the EPAct 2005 may have an adverse impact on our business.

In 2003, the Northeastern United States and parts of Canada suffered a massive blackout allegedly stemming from transmission problems originating in Ohio. In part as a result of this, the EPAct 2005 requires the FERC to select an industry self-regulatory organization which will impose mandatory reliability rules and standards. We cannot predict the impact of this on us.

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 supply of electricity, at both the wholesale and retail level. In addition, any future legislation favoring large, vertically integrated utilities and a concentration of ownership of such utilities could impact 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 unfunded 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 Employee Retirement Income Security Act of 1974 (ERISA) and some of the plans are underfunded. As of December 31, 2005, our U.S. pension plans had an unfunded accumulated benefit obligation of approximately $90 million, and an unfunded projected benefit obligation of approximately $149 million, in aggregate as calculated in accordance with Financial Accounting Standards Board (FASB) Statement No. 132R (FASB 132R), *Employers Disclosures about Pensions and Other Postretirement Benefits.* As of December 31, 2005, our non-U.S. pension plans were overfunded on an accumulated benefit obligation basis by approximately $68 million, and on a projected benefit obligation basis by approximately $51 million, in the aggregate, as calculated in accordance with FASB 132R. Unless the unfunded 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.

Changes in technology may significantly impact 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 impact 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 impacted. In addition, such an attack could impact 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 personal injury 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 hurt our financial results and materially harm 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 Lovett and Bowline generation facilities in New York are subject to disputes with local tax authorities regarding property tax assessments and with the New York State Department of Environmental Conservation (NYDEC) regarding environmental controls. We are also in discussions with the NYISO and utilities regarding an agreement that would compensate Mirant Lovett for its contribution to the reliability of the New York electric power system. The facilities are forecasted to have negative operating cash flows at their current tax valuations. Until a settlement is reached on property taxes, environmental controls and reliability that would permit economically feasible operation, our subsidiaries that own the facilities, Mirant Lovett and Mirant Bowline, LLC (Mirant Bowline), will remain in Chapter 11. The Lovett and Bowline facilities are currently in negotiations on all of these issues. Although negotiations are continuing, resolutions may not be reached in the near future or not at all. Until resolutions are reached and the companies emerge from bankruptcy, we will not have access to the cash from operations generated from these subsidiaries.

Mirant NY-Gen, which includes 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 made by Mirant Americas Inc. (Mirant Americas), with the approval of and under the supervision of the Bankruptcy Court. Mirant NY-Gen is currently discussing with the FERC appropriate remediation for a sinkhole discovered in May 2005 in the dam at the Swinging Bridge facility. We also conducted a flood study to determine downstream consequences if the maximum capacities of the reservoirs were exceeded at our New York Swinging Bridge, Rio and Mongaup generation facilities, which may cause the FERC to request that Mirant NY-Gen remediate those dams as well. Mirant NY-Gen has initiated discussions with the FERC for surrendering its permits to operate all the hydro electric facilities at Swinging Bridge, Rio and Mongaup, and expects to begin that formal process soon. It is not possible at this point to determine the cost of remediating the dam and surrendering the permits, but such costs may be substantial.

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 date of the bankruptcy filing 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 few exceptions, all claims that arose prior to our bankruptcy filing and before confirmation of the Plan 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 cannot be certain that the bankruptcy proceeding will not adversely affect our operations going forward.

Although we emerged from bankruptcy upon consummation of the Plan, we cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations going forward, including our ability to negotiate favorable terms from suppliers, hedging counterparties and others and to attract and retain customers. The failure to obtain such favorable terms and retain customers could adversely affect our financial performance.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

The following properties were owned or leased as of December 31, 2005:

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)**	**2005 Capacity Factor(3)**
United States							
Mid-Atlantic Region:							
Chalk Point	Maryland	Intermediate/Baseload/Peaking	Natural Gas/Coal/Oil	100	2,429	2,429	31 %
Dickerson	Maryland	Baseload/Peaking	Natural Gas/Coal/Oil	100	853	853	48 %
Morgantown	Maryland	Baseload/Peaking	Coal/Oil	100	1,492	1,492	50 %
Potomac River	Virginia	Intermediate/Baseload	Coal/Oil	100	482	482	31 %
Total Mid-Atlantic					5,256	5,256	39 %
Northeast Region:							
Canal	Massachusetts	Intermediate	Natural Gas/Oil	100	1,112	1,112	50 %
Kendall	Massachusetts	Intermediate/Peaking	Natural Gas/Oil	100	256	256	59 %
Martha s Vineyard	Massachusetts	Peaking	Diesel	100	14	14	1 %
Wyman	Maine	Peaking	Fuel Oil	1.4	614	9	
Total New England(4)					1,996	1,391	51 %
Bowline	New York	Intermediate/Peaking	Natural Gas/Oil	100	1,125	1,125	12 %
Grahamsville	New York	Baseload	Hydro	100	16	16	66 %
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	25 %
Rio	New York	Intermediate/Peaking	Hydro	100	9	9	30 %
Shoemaker	New York	Peaking	Natural Gas/Jet Fuel	100	44	44	
Swinging Bridge	New York	Intermediate/Peaking	Hydro	100	12	12	14 %
Total New York				100	1,672	1,672	20 %
Total Northeast					3,668	3,063	34 %
West Region:							
Contra Costa	California	Intermediate	Natural Gas	100	674	674	6 %
Pittsburg	California	Intermediate	Natural Gas	100	1,311	1,311	6 %
Potrero	California	Baseload/Peaking	Natural Gas/Oil	100	362	362	14 %
Total California					2,347	2,347	7 %
Mirant Texas	Texas	Baseload/Peaking	Natural Gas	100	532	532	38 %
Mirant Las Vegas	Nevada	Intermediate	Natural Gas	100	518	518	38 %
Mirant Wichita Falls(5)	Texas	Peaking	Natural Gas	100	77	77	19 %
Total West					3,474	3,474	17 %
Mid-Continent Region:							
Zeeland	Michigan	Intermediate/Peaking	Natural Gas	100	837	837	8 %
West Georgia(6)	Georgia	Peaking	Natural Gas/Oil	100	605	605	2 %
Sugar Creek	Indiana	Peaking	Natural Gas	100	535	535	10 %
Shady Hills(6)	Florida	Peaking	Natural Gas	100	468	468	8 %
Total Mid-Continent					2,445	2,445	7 %
United States Total					14,843	14,238	27 %
Philippines							
Sual(7)	Philippines	Baseload	Coal	94.9	1,218	1,155	37 %
Ilijan	Philippines	Baseload	Natural Gas	20	1,200	240	
Pagbilao	Philippines	Baseload	Coal	95.7	735	704	38 %
Sangi	Philippines	Baseload/Peaking/ Standby	Coal/Oil	50	75	38	50 %
Panay	Philippines	Peaking/Intermediate/Baseload	Oil	50	71	35	61 %
Carmen	Philippines	Standby/Peaking	Heavy Fuel Oil	50	37	19	9 %
Avon River	Philippines	Peaking/Intermediate/Baseload	Oil	50	18	9	26 %
Mindoro	Philippines	Peaking/Intermediate/Baseload	Heavy Fuel Oil	50	7	3	48 %
The Philippines Total					3,361	2,203	38 %
Caribbean							

PowerGen	Trinidad and Tobago	Intermediate/Peaking/Baseload	Natural Gas	39	1,157	451	52 %
Jamaica Public Service Company Limited	Jamaica	Intermediate/Baseload/Peaking	Oil/Hydro	80	603	482	52 %
Grand Bahama Power	Bahamas	Peaking/Intermediate/Baseload	Oil	55.4	151	83	44 %
CUC	Netherlands Antilles	Baseload/Peaking	Pitch/Refinery Gas	25.5	133	34	
Caribbean Total					2,044	1,050	51 %
Total Mirant					20,248	17,491	

Distribution Business	Location	Mirant s % Ownership Interest	Customers/ end-users (in thousands)
Grand Bahama Power	Bahamas	55.4	19
Jamaica Public Service Company Limited	Jamaica	80.0	555
Visayan Electric Company, Inc	Philippines	2.0	274
Total			848

Construction Projects:

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)
Bowline expansion(8)	New York	Intermediate	Natural Gas	100	750	750
Contra Costa expansion(8)	California	Intermediate	Natural Gas	100	580	580
Nabas(9)	Philippines	Baseload	Oil	50	11	6
New Washington(9)	Philippines	Baseload	Oil	50	5	2
Points Lisas expansion(10)	Trinidad	Baseload	Natural Gas	39	208	81

(1) Amounts reflect our percentage economic interest in the total MW.

(2) MW amounts reflect net dependable capacity.

(3) Capacity factor is the average percentage of full capacity used over a year.

(4) Total MW reflects a 1.4% ownership interest, or 8.8 MW, in the 614 MW Wyman plant.

(5) We currently expect to sell this facility in 2006.

(6) Generating plant is operated by an independent third party.

(7) Mirant will acquire the remaining 5.15% in the first quarter of 2006.

(8) We do not intend to complete these construction projects and will either sell or abandon these projects.

(9) Nabas and New Washington facilities are scheduled to be in operations pending tariff approval in 2006.

(10) On December 6, 2005, PowerGen and T&TEC executed a 30-year 208 MW power sales agreement. PowerGen began construction of the facility to produce this capacity on February 23, 2006, and estimates a commercial operations date of February 2007.

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

Item 3. ***Legal Proceedings***

Chapter 11 Proceedings

On the Petition Date, and various dates thereafter, the Mirant Debtors filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. On August 21, 2003 and September 8, 2003, the Bankruptcy Court entered orders establishing a December 16, 2003, bar date (the Bar Date) for filing proofs of claim against the Mirant Debtors estates.

Most of the material claims filed against the Mirant Debtors estates were disallowed or were resolved and became allowed claims before confirmation of the Plan. For example, the claims filed by the California Attorney General, PG&E, various other California parties, plaintiffs in certain rate payer class action lawsuits, the plaintiffs in certain shareholder or bondholder litigation, and Utility Choice, L.P., which are described in our 2004 Form 10-K, are among the claims that were resolved prior to confirmation of the Plan. A number of claims, however, remain unresolved.

Except for claims and other obligations not subject to discharge under the Plan and unless otherwise provided below, all claims against the Mirant Debtors estates representing obligations that arose prior to July 14, 2003, are subject to compromise under the Plan. This means that the claimant will receive a distribution of Mirant common stock, cash, or both common stock and cash in accordance with the terms of the Plan in satisfaction of the claim. As a result, the exact amount of the claim may still be litigated, but we will not be required to make any payment in respect of such litigation until a resolution is obtained, through settlement, judgment or otherwise.

As of December 31, 2005, approximately 23.5 million of the shares of Mirant common stock to be distributed under the Plan to creditors have been reserved for distribution with respect to claims that are disputed by the Mirant Debtors and have not been resolved. Under the terms of the Plan, to the extent such claims are resolved now that we have emerged from bankruptcy the claimants will be paid from the reserve of 23.5 million shares on the same basis as if they had been paid out when the Plan became effective. That means that their allowed claims will receive the same pro rata distributions of common stock, cash or both common stock and cash as previously allowed claims in accordance with the terms of the Plan. It is our view that we have funded the disputed claims reserve at a sufficient level to settle the remaining unresolved proofs of claim we received during the bankruptcy proceedings and any claims resulting from our rejection of certain contracts with PEPCO, as described below in *PEPCO Litigation*. However, to the extent the aggregate amount of the payouts determined to be due with respect to such disputed claims ultimately exceeds the amount of the funded claim reserve, Mirant would have to issue additional shares of common stock to address the shortfall, which would dilute existing shareholders, and pay additional cash amounts as necessary under the terms of the Plan to satisfy such pre-petition claims. We will continue to monitor our obligations as the disputed claims are resolved. If we are required to issue additional shares of common stock to satisfy unresolved claims, certain parties who under the Plan received common stock and warrants are also entitled to receive additional shares of common stock to avoid dilution of their distributions under the Plan.

Our Lovett and Bowline generation facilities in New York are subject to disputes with local tax authorities regarding property tax assessments and with the NYDEC regarding environmental controls. Mirant Lovett is also in discussions with the NYISO and utilities regarding an agreement that would compensate Mirant Lovett for the contribution of the Lovett facility to the reliability of the New York electric power system. The facilities are forecasted to have negative operating cash flows at their current tax valuations. Until a settlement is reached on property taxes, environmental controls and reliability, that would permit economically feasible operation, our subsidiaries that own the facilities, Mirant Lovett and Mirant Bowline, will remain in Chapter 11. The Lovett and Bowline facilities are currently in settlement discussions on all these issues. Although negotiations are continuing, settlements may not be reached in the near future, or at all. Until such settlements are reached and the companies emerge from bankruptcy, we will not have access to the cash from operations generated from these subsidiaries. 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 made by Mirant Americas with the approval of, and under the supervision of, the Bankruptcy Court. Mirant NY-Gen is currently discussing with the FERC appropriate remediation for a sinkhole discovered in May 2005 in the dam at the Swinging Bridge facility. We conducted a flood study to determine downstream consequences if the maximum capacities of the reservoirs were exceeded at our New York Swinging Bridge, Rio and Mongaup generation facilities, and Mirant NY-Gen could be requested by the FERC to remediate those dams as well. Mirant NY-Gen has initiated discussions with the FERC for surrendering its permits to operate all the hydro electric facilities at Swinging Bridge, Rio and Mongaup, and expects to begin that formal process soon. It is not possible at this point to determine the cost of remediating the dam at Swinging Bridge and surrendering the permits, but such costs may be substantial.

PEPCO Litigation

In 2000, Mirant purchased power generating facilities and other assets from PEPCO, including certain PPAs between PEPCO and third parties. Under the terms of the Asset Purchase and Sale Agreement (APSA), Mirant and PEPCO entered into the Back-to-Back Agreement with respect to certain PPAs, including PEPCO s long-term PPAs with Ohio Edison and Panda-Brandywine L.P. (Panda), under which (1) PEPCO agreed to resell to Mirant all capacity, energy, ancillary services and other benefits to which it is entitled under those agreements; and (2) Mirant agreed to pay PEPCO each month all amounts due from PEPCO to the sellers under those agreements for the immediately preceding month associated with such capacity, energy, ancillary services and other benefits. The Ohio Edison PPA terminated in December 2005 and the Panda PPA runs until 2021. Under the Back-to-Back Agreement, Mirant is obligated to purchase power from PEPCO at prices that are typically higher than the market prices for power.

Mirant assigned its rights and obligations under the Back-to-Back Agreement to Mirant Americas Energy Marketing. In the Chapter 11 cases of the Mirant Debtors, PEPCO asserted that an Assignment and Assumption Agreement dated December 19, 2000, that includes as parties PEPCO and various subsidiaries of ours causes our subsidiaries that are parties to the agreement to be jointly and severally liable to PEPCO for various obligations, including the obligations under the Back-to-Back Agreement. The Mirant Debtors have sought to reject the APSA, the Back-to-Back Agreement, and the Assignment and Assumption Agreement, and the rejection motions have not been resolved. Under the Plan, the obligations of the Mirant Debtors under the APSA (including any other agreements executed pursuant to the terms of the APSA and found by the final court order to be part of the APSA), the Back-to-Back Agreement, and the Assignment and Assumption Agreement are to be performed by Mirant Power Purchase, whose performance is guaranteed by Mirant. If any of the agreements is successfully rejected, the obligations of Mirant Power Purchase and Mirant s guarantee obligations terminate with respect to that agreement, and PEPCO would be entitled to a claim in the Chapter 11 proceedings for any resulting damages. That claim would then be addressed under the terms of the Plan.

PEPCO Contract Litigation. On August 28, 2003, the Mirant Debtors filed a motion in the bankruptcy proceedings to reject the Back-to-Back Agreement (the First Rejection Motion). On October 9, 2003, the United States District Court for the Northern District of Texas entered an order that had the effect of transferring the First Rejection Motion to that court from the Bankruptcy Court. In December 2003, the district court denied the First Rejection Motion. The district court ruled that the Federal Power Act preempts the Bankruptcy Code and that a bankruptcy court cannot affect a matter within the FERC s jurisdiction under the Federal Power Act, including the rejection of a wholesale power purchase agreement regulated by the FERC.

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The Mirant Debtors appealed the district court s order to the United States Court of Appeals for the Fifth Circuit (the Fifth Circuit). The Fifth Circuit reversed the district court s decision, holding that the Bankruptcy Code authorizes a district court (or bankruptcy court) to reject a contract for the sale of electricity that is subject to the FERC s regulation under the Federal Power Act as part of a bankruptcy proceeding and that the Federal Power Act does not preempt that authority. The Fifth Circuit remanded the proceeding to the district court for further action on that motion. The Fifth Circuit indicated that on remand the district court could consider applying a more rigorous standard than the business judgment standard typically applicable to contract rejection decisions by debtors in bankruptcy, which more rigorous standard would take into account the public interest in the transmission and sale of electricity.

On December 9, 2004, the district court held that the Back-to-Back Agreement was a part of and not severable from, and therefore could not be rejected apart from, the APSA. The Mirant Debtors have appealed the district court s December 9, 2004, decision to the Fifth Circuit.

On January 21, 2005, the Mirant Debtors filed a motion in the bankruptcy proceedings to reject the APSA, including the Back-to-Back Agreement but not including other agreements entered into between Mirant and its subsidiaries and PEPCO under the terms of the APSA (the Second Rejection Motion). On March 1, 2005, the district court ruled that it would withdraw the reference to the Bankruptcy Court of the Second Rejection Motion and would itself hear that motion. On August 16, 2005, the district court informally stayed the Second Rejection Motion pending rulings by the Fifth Circuit on the Mirant Debtors appeals from the district court s December 9, 2004, decision denying the First Rejection Motion and from the district court s March 1, 2005, order as subsequently modified described below in *PEPCO Litigation Payments to PEPCO under Back-to-Back Agreement*.

On December 1, 2005, the Mirant Debtors filed a complaint with the Bankruptcy Court seeking to recharacterize the Back-to-Back Agreement as a debt obligation arising prior to the filing of the Chapter 11 proceedings. The complaint seeks the recovery of all payments made to PEPCO under the Back-to-Back Agreement since the filing of the Chapter 11 proceedings. If the Mirant Debtors succeed in recovering such payments, PEPCO would receive a claim in the bankruptcy proceedings for the amount recovered. Also on December 1, 2005, the Mirant Debtors filed a motion in the Bankruptcy Court to assume, assume and assign, or reject certain agreements with PEPCO and for the disgorgement of funds paid post-petition under the Back-to-Back Agreement (the Motion to Assume or Reject). This motion is pending in the Bankruptcy Court. The likely outcome of these proceedings and the previously filed motions to reject the Back-to-Back Agreement and the APSA cannot now be determined.

Payments to PEPCO under Back-to-Back Agreement. On December 9, 2004, in an effort to halt further out-of-market payments under the Back-to-Back Agreement while awaiting resolution of issues related to the potential rejection of the Back-to-Back Agreement (but prior to notice of entry of the district court s order of December 9, 2004), the Mirant Debtors filed a notice in the Bankruptcy Court stating that the Mirant Debtors were suspending further payments to PEPCO under the Back-to-Back Agreement absent further order of the court (the Suspension Notice). On January 19, 2005, the Bankruptcy Court entered an order requiring the Mirant Debtors to pay amounts due under the Back-to-Back Agreement in January 2005 and thereafter until either (1) the Mirant Debtors filed a motion to reject the APSA, (2) the Fifth Circuit issued an order reversing the district court s order of December 9, 2004, denying the motion to reject the Back-to-Back Agreement, or (3) the Mirant Debtors were successful in having the obligations under the Back-to-Back Agreement recharacterized as debt obligations. PEPCO filed an appeal of the Bankruptcy Court s January 19, 2005, order. On January 21, 2005, the Mirant Debtors filed the Second Rejection Motion.

On March 1, 2005, the district court withdrew the reference to the Bankruptcy Court of the Second Rejection Motion, dismissed PEPCO s appeal of the January 19, 2005, order of the Bankruptcy Court as moot, and ordered the Mirant Debtors to pay PEPCO all past-due, unpaid obligations under the

Back-to-Back Agreement by March 10, 2005. On March 7, 2005, the district court modified the March 1, 2005, order to delay until March 18, 2005, the date by which the Mirant Debtors were to pay past-due, unpaid obligations under the Back-to-Back Agreement. On March 16, 2005, the district court further modified its order of March 1, 2005, to clarify that the amounts to be paid by the Mirant Debtors by March 18, 2005, did not include any amounts that became due prior to the filing of the Chapter 11 cases on July 14, 2003. The Mirant Debtors have appealed the district court s March 1, 2005, order, as modified, to the Fifth Circuit. The Mirant Debtors have paid all amounts due under the Back-to-Back Agreement accruing since the Petition Date.

Potential Adjustment Related to Panda Power Purchase Agreement. At the time of the acquisition of the Mirant Mid-Atlantic assets from PEPCO, Mirant also entered into an agreement with PEPCO that, as subsequently modified, provided that the price paid by Mirant for its December 2000 acquisition of PEPCO assets would be adjusted if by April 8, 2005, a binding court order had been entered finding that the Back-to-Back Agreement violated PEPCO s power purchase agreement with Panda (the Panda PPA) as a prohibited assignment, transfer or delegation of the Panda PPA or because it effected a prohibited delegation or transfer of rights, duties or obligations under the Panda PPA that was not severable from the rest of the Back-to-Back Agreement. Panda initiated legal proceedings in 2000 asserting that the Back-to-Back Agreement violated provisions in the Panda PPA prohibiting PEPCO from assigning the Panda PPA or delegating its duties under the Panda PPA to a third party without Panda s prior written consent. On June 10, 2003, the Maryland Court of Appeals, Maryland s highest court, ruled that the assignment of certain rights and delegation of certain duties by PEPCO to Mirant did violate the non-assignment provision of the Panda PPA and was unenforceable. The court, however, left open the issues whether the provisions found to violate the Panda PPA could be severed and the rest of the Back-to-Back Agreement enforced and whether Panda s refusal to consent to the assignment of the Panda PPA by PEPCO to Mirant was unreasonable and violated the Panda PPA. The Company maintains that the June 10, 2003, decision by the Maryland Court of Appeals does not suffice to trigger a purchase price adjustment under the agreement between Mirant and PEPCO. If that court order were found to have triggered the purchase price adjustment, the agreement between Mirant and PEPCO provides that the amount of the adjustment would be negotiated in good faith by the parties or determined by binding arbitration so as to compensate PEPCO for the termination of the benefit of the Back-to-Back Agreement while also holding Mirant economically indifferent from such court order.

PEPCO Avoidance Action. On July 13, 2005, Mirant and several of its subsidiaries, including Mirant Mid-Atlantic and Mirant Americas Generation, filed a lawsuit against PEPCO before the Bankruptcy Court asserting that Mirant did not receive fair value in return for the purchase price paid for the PEPCO assets and that the acquisition occurred at a time when Mirant was either insolvent or was rendered insolvent as a result of the transaction. The suit seeks damages for fraudulent transfer under 11 U.S.C. §§ 544 and 550 and applicable state law and disallowance of claims filed by PEPCO in the Chapter 11 proceedings. On November 3, 2005, the district court granted a motion filed by PEPCO asking that the suit be heard by the district court rather than the Bankruptcy Court. The likely outcome of this proceeding cannot now be determined, and the Company cannot estimate what recovery, if any, it may obtain in this action.

Plan Treatment of PEPCO. Pending a final determination of the Mirant Debtors ability to reject the APSA, the Back-to-Back Agreement, and certain other agreements with PEPCO, the Mirant Debtors obligations under the APSA and the Back-to-Back Agreement are interim obligations of Mirant Power Purchase and are unconditionally guaranteed by Mirant. If the Mirant Debtors succeed in rejecting any of these agreements, the obligations of Mirant Power Purchase and Mirant s guarantee obligations terminate with respect to that agreement, and PEPCO would be entitled to a claim in the Chapter 11 proceedings for any resulting damages. PEPCO s resulting rejection damages claim would be satisfied pursuant to the terms of the Plan. See *Chapter 11 Proceedings* above for further discussion of the treatment under the Plan of unresolved claims in the Chapter 11 proceedings.

California and Western Power Markets

California Rate Payer Litigation. Certain of our subsidiaries are subject to litigation related to their activities in California and the western power markets and the high prices for wholesale electricity experienced in the western markets during 2000 and 2001. Various lawsuits were filed in 2000 through 2003 that asserted claims under California law based on allegations that certain owners of electricity generation facilities in California and energy marketers, including the Company, Mirant Americas Energy Marketing and our subsidiaries owning generating facilities in California, engaged in various unlawful and anti-competitive acts that served to manipulate wholesale power markets and inflate wholesale electricity prices in California. All of these suits have been dismissed by final orders except for six such suits that were filed between November 27, 2000, and May 2, 2001, in various California Superior Courts and consolidated before the Superior Court for the County of San Diego for pretrial purposes. Although the plaintiffs dismissed Mirant from those suits, they have not filed to dismiss certain of our subsidiaries that are also defendants. On October 3, 2005, the California state court dismissed those six consolidated suits on the grounds that the plaintiffs claims were barred by federal preemption as a result of the Federal Power Act. On December 5, 2005, the plaintiffs filed an appeal of the dismissal. The plaintiffs in the six consolidated suits did not file claims in the bankruptcy proceedings of our subsidiaries, and we expect that their claims are barred by the Plan now that it has become effective.

Shareholder-Bondholder Litigation

Mirant Securities Consolidated Action. Twenty lawsuits filed in 2002 against Mirant and four of its officers have been consolidated into a single action, In re Mirant Corporation Securities Litigation, before the United States District Court for the Northern District of Georgia. In their original complaints, the plaintiffs allege, among other things, that the defendants violated federal securities laws by making material misrepresentations and omissions to the investing public regarding Mirant s business operations and future prospects during the period from January 19, 2001, through May 6, 2002, due to potential liabilities arising out of its activities in California during 2000 and 2001. The plaintiffs seek unspecified damages, including compensatory damages, and the recovery of reasonable attorneys fees and costs.

In November 2002, the plaintiffs filed an amended complaint that added as defendants Southern Company (Southern), the directors of Mirant immediately prior to its initial public offering of stock, and various firms that were underwriters for the initial public offering by the Company. In addition to the claims set out in the original complaint, the amended complaint asserts claims under the Securities Act of 1933, alleging that the registration statement and prospectus for the initial public offering in 2000 of Mirant s old common stock terminated under the Plan misrepresented and omitted material facts. On July 14, 2003, the district court dismissed the claims asserted by the plaintiffs based on the Company s California business activities but allowed the case to proceed on the plaintiffs other claims. On December 11, 2003, the plaintiffs filed a proof of claim against Mirant in the Chapter 11 proceedings, but they subsequently withdrew their claim in October 2004. On August 29, 2005, the district court, at the request of the plaintiffs, dismissed Mirant as a defendant in this action.

A master separation agreement between Mirant and Southern entered into in conjunction with Mirant s spin off from Southern in 2001 obligates Mirant to indemnify Southern for any losses arising out of any acts or omissions by Mirant and its subsidiaries in the conduct of the business of Mirant and its subsidiaries. Mirant has filed to reject the separation agreement in the Chapter 11 proceedings. Any damages determined to be owed to Southern arising from the rejection of the separation agreement will be addressed as a claim in the Chapter 11 proceedings under the terms of the Plan. The underwriting agreements between Mirant and the various firms added as defendants that were underwriters for the initial public offering by the Company in 2000 also provide for Mirant to indemnify such firms against any losses arising out of any acts or omissions by Mirant and its subsidiaries. The underwriters filed a claim against Mirant in the Chapter 11 proceedings that was subordinated to claims of Mirant s creditors and extinguished under the Plan.

Shareholder Derivative Litigation. Four purported shareholders derivative suits have been filed against Mirant, its directors and certain officers of the Company. Two of those suits have been consolidated. These lawsuits allege that the directors breached their fiduciary duty by allowing the Company to engage in alleged unlawful or improper practices in the California energy markets in 2000 and 2001. The Company practices alleged in these lawsuits largely mirror those alleged with respect to the Company s activities in California in the shareholder litigation discussed above. One suit also alleges that the defendant officers engaged in insider trading. The complaints seek unspecified damages on behalf of the Company, including attorneys fees, costs and expenses and punitive damages. The captions of each of the cases follow:

Caption	Date Filed
Kester v. Correll, et al.	June 26, 2002
Pettingill v. Fuller, et al.	July 30, 2002
White v. Correll, et al.	August 9, 2002
Cichocki v. Correll, et al.	November 7, 2002

The Kester and White suits were filed in the Superior Court of Fulton County, Georgia, and were consolidated on March 13, 2003, under the name *In re Mirant Corporation Derivative Litigation*. The consolidated action has been removed by Mirant to the United States District Court for the Northern District of Georgia. The Pettingill suit was filed in the Court of Chancery for New Castle County, Delaware, and was removed by Mirant to the United States District Court for the District of Delaware. The Cichocki suit was filed in the United States District Court for the Northern District of Georgia. The order entered by the Bankruptcy Court confirming the Plan enjoins the prosecution of these actions and requires that they be dismissed. On March 8, 2006, the Bankruptcy Court entered an order compelling the plaintiffs in these actions to dismiss their complaints in accordance with the terms of the Plan. The plaintiffs in the consolidated Kester and White suits and in the Pettingill suit have filed to dismiss their complaints.

Mirant Americas Generation Bondholder Suit. On June 10, 2003, certain holders of senior notes of Mirant Americas Generation maturing after 2006 filed a complaint in the Court of Chancery of the State of Delaware*, California Public Employees Retirement System, et al. v. Mirant Corporation, et al.,* that named as defendants Mirant, Mirant Americas, Mirant Americas Generation, certain past and present Mirant directors, and certain past and present Mirant Americas Generation managers. Among other claims, the plaintiffs assert that a restructuring plan pursued by the Company prior to its filing a petition for reorganization under Chapter 11 of the Bankruptcy Code was in breach of fiduciary duties allegedly owed to them by Mirant, Mirant Americas and Mirant Americas Generation s managers. In addition, the plaintiffs challenge certain dividends and distributions made by Mirant Americas Generation prior to the Petition Date. The plaintiffs seek damages in excess of $1 billion. Mirant has removed this suit to the United States District Court for the District of Delaware. This action was stayed with respect to the Mirant entities that are defendants by the filing of the Chapter 11 proceedings of these entities. The order entered by the Bankruptcy Court confirming the Plan enjoins the prosecution of this action and requires that it be dismissed. On March 8, 2006, the Bankruptcy Court entered an order compelling the plaintiffs in this action to dismiss their complaints in accordance with the terms of the Plan.

U.S. Government Inquiries

Department of Justice Inquiries. In November 2002, Mirant received a subpoena from the DOJ, acting through the United States Attorney s office for the Northern District of California, requesting information about its activities and those of its subsidiaries for the period since January 1, 1998. The subpoena requested information related to the California energy markets and other topics, including the reporting of inaccurate information to the trade press that publish natural gas or electricity spot price data. The subpoena was issued as part of a grand jury investigation. The DOJ s investigation of the reporting of inaccurate natural gas price information is continuing, and we have held preliminary discussions with DOJ regarding the disposition of this matter. The DOJ s investigation is based upon the same circumstances that were the subject of an investigation by the Commodity Futures Trading Commission (CFTC) that was settled in December 2004. As described in the Company s Annual Report on Form 10-K for the year ended December 31, 2004, in *Legal Proceedings Other Governmental Proceedings CFTC Inquiry*, Mirant and Mirant Americas Energy Marketing pursuant to the settlement consented to the entry of an order by the CFTC in which it made findings, which are neither admitted nor denied by Mirant and Mirant Americas Energy Marketing, that (1) from January 2000 through December 2001, certain Mirant Americas Energy Marketing natural gas traders (a) knowingly reported inaccurate price, volume, and/or counterparty information regarding natural gas cash transactions to publishers of natural gas indices and (b) inaccurately reported to index publishers transactions observed in the market as Mirant Americas Energy Marketing transactions and (2) from January to October 2000, certain Mirant Americas Energy Marketing west region traders knowingly delivered the false reports in an attempt to manipulate the price of natural gas. Under the settlement, the CFTC received a subordinated allowed, unsecured claim against Mirant Americas Energy Marketing of $12.5 million in the Chapter 11 proceedings. The DOJ could decide that further action against the Company is not appropriate or could seek indictments against one or more Mirant entities, or the DOJ and the Company could agree to a disposition that might involve undertakings or fines, the amount of which cannot be reasonably estimated at this time but which could be material. The Company has cooperated fully with the DOJ and intends to continue to do so.

Department of Labor Inquiries. On August 21, 2003, the Company received a notice from the Department of Labor (the DOL) that it was commencing an investigation pursuant to which it was undertaking to review various documents and records relating to the Mirant Services Employee Savings Plan and the Mirant Services Bargaining Unit Employee Savings Plan. The DOL has interviewed Mirant personnel regarding those plans. The Company intends to continue to cooperate fully with the DOL.

Environmental Matters

EPA Information Request. In January 2001, the EPA issued a request for information to Mirant concerning the air permitting and air emissions control implications under the NSR of past repair and maintenance activities at the Potomac River plant in Virginia and the Chalk Point, Dickerson and Morgantown plants in Maryland. The requested information concerns the period of operations that predates the Company subsidiaries ownership and lease of those plants. Mirant has responded fully to this request. Under the APSA, PEPCO is responsible for fines and penalties arising from any violation associated with historical operations prior to the Company subsidiaries acquisition or lease of the plants. If the Mirant Debtors succeed in rejecting the APSA as described above in *PEPCO Litigation PEPCO Contract Litigation*, PEPCO may assert that it has no obligation to reimburse Mirant for any fines or penalties imposed upon Mirant for periods prior to the Company subsidiaries acquisition or lease of the plants. If a violation is determined to have occurred at any of the plants, the Company 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. If such violation is determined to have occurred after the Company s subsidiaries acquired or leased the plants or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, the Company subsidiary owning or leasing the plant at issue would also

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be subject to fines and penalties by the state or federal government for the period subsequent to its acquisition or lease of the plant, the cost of which may be material.

Mirant Potomac River Notice of Violation. On September 10, 2003, the Virginia DEQ issued an NOV to Mirant Potomac River alleging that it violated its Virginia Stationary Source Permit to Operate by emitting NOx in excess of the cap established by the permit for the 2003 summer ozone season. Mirant Potomac River responded to the NOV, asserting that the cap is unenforceable, noting that it can comply through the purchase of emissions allowances and raising other equitable defenses. Virginia s civil enforcement statute provides for injunctive relief and penalties. On January 22, 2004, the EPA issued an NOV to Mirant Potomac River alleging the same violation of its Virginia Stationary Source Permit to Operate as set out in the NOV issued by the Virginia DEQ.

On September 27, 2004, Mirant Potomac River, Mirant Mid-Atlantic, the Virginia DEQ, the Maryland Department of the Environment, the DOJ and the EPA entered into, and filed for approval with the United States District Court for the Eastern District of Virginia, a consent decree that, if approved, will resolve Mirant Potomac River s potential liability for matters addressed in the NOVs previously issued by the Virginia DEQ and the EPA. The consent decree requires Mirant Potomac River and Mirant Mid-Atlantic to (1) install pollution control equipment at the Potomac River plant and at the Morgantown plant leased by Mirant Mid-Atlantic in Maryland, (2) comply with declining system-wide ozone season NOx emissions caps from 2004 through 2010, (3) comply with system-wide annual NOx emissions caps starting in 2004, (4) meet seasonal system average emissions rate targets in 2008 and (5) pay civil penalties and perform supplemental environmental projects in and around the Potomac River plant expected to achieve additional environmental benefits. Except for the installation of the controls planned for the Potomac River units and the installation of SCR or equivalent technology at Mirant Mid-Atlantic s Morgantown Units 1 and 2 in 2007 and 2008, the consent decree does not obligate the Company s subsidiaries to install specifically designated technology, but rather to reduce emissions sufficiently to meet the various NOx caps. Moreover, as to the required installations of SCRs at Morgantown, Mirant Mid-Atlantic may choose not to install the technology by the applicable deadlines and leave the units off either permanently or until such time as the SCRs are installed. The consent decree is subject to the approval of the district court and the Bankruptcy Court.

The owners/lessors under the lease-financing transactions covering the Morgantown and Dickerson plants (the Owners/Lessors) objected to the proposed consent decree in the Bankruptcy Court and filed a motion to intervene in the district court action. As part of a resolution of disputed matters in the Chapter 11 proceedings, the Owners/Lessors have now agreed not to object to the consent decree, subject to certain terms set forth in the Plan and Confirmation Order.

On July 22, 2005, the district court granted a motion filed by the City of Alexandria seeking to intervene in the district court action, although the district court imposed certain limitations on the City of Alexandria s participation in the proceedings. On September 23, 2005, the City of Alexandria filed a motion seeking authority to file an amended complaint in the action seeking injunctive relief and civil penalties under the Clean Air Act for alleged violations by Mirant Potomac River of its Virginia Stationary Source Permit To Operate and the State of Virginia s State Implementation Plan. Based upon a computer modeling, the City of Alexandria asserted that emissions from the Potomac River plant exceed NAAQS for SO2, nitrogen dioxide (NO2), and particulate matter. The City of Alexandria also contended based on its modeling analysis that the plant s emissions of hydrogen chloride and hydrogen fluoride exceed Virginia state emissions standards. Mirant Potomac River disputes the City of Alexandria s allegations that it has violated the Clean Air Act and Virginia law. On December 2, 2005, the district court denied the City of Alexandria s motion seeking to file an amended complaint.

Mirant Potomac River Downwash Study. On September 23, 2004, the Virginia DEQ and Mirant Potomac River entered into an order by consent with respect to the Potomac River plant under which

Mirant Potomac River agreed to perform a modeling analysis to assess the potential effect of downwash from the plant (1) on ambient concentrations of SO2, NO2, carbon monoxide (CO) and particulate matter less than or equal to 10 micrometers (PM10) for comparison to the applicable NAAQS and (2) on ambient concentrations of mercury for comparison to Virginia Standards of Performance for Toxic Pollutants. Downwash is the effect that occurs when aerodynamic turbulence induced by nearby structures causes emissions from an elevated source, such as a smokestack, to be mixed rapidly toward the ground resulting in higher ground level concentrations of emissions. If the modeling analysis indicates that emissions from the facility may cause exceedances of the NAAQS for SO2, NO2, CO or PM10, or exceedances of mercury compared to Virginia Standards of Performance for Toxic Pollutants, the consent order requires Mirant Potomac River to submit to the Virginia DEQ a plan and schedule to eliminate and prevent such exceedances on a timely basis. Upon approval by the Virginia DEQ of the plan and schedule, the approved plan and schedule is to be incorporated by reference into the consent order. The results of the computer modeling analysis showed that emissions from the Potomac River plant have the potential to contribute to localized, modeled instances of exceedances of the NAAQS for SO2, NO2 and PM10 under certain conditions. In response to a directive from the Virginia DEQ, Mirant Potomac River temporarily shut down the Potomac River plant on August 24, 2005, pending identification and implementation of modifications to the plant or its operations, which modifications could be material. On September 21, 2005, Mirant Potomac River commenced partial operation of one unit of the plant. The financial and operational implications of the discontinued or limited operation of the Potomac River plant or any such modifications are not known at this time, but could be material depending on the length of time that operations are discontinued or limited.

On August 24, 2005, power production at all five units of Potomac River was temporarily halted in response to a directive from the Virginia DEQ. The decision to temporarily shut down the facility arose from findings of a study commissioned under an agreement with the Virginia DEQ to assess the air quality in the area immediately surrounding the facility. The Virginia DEQ s directive was based on results from the study s computer modeling showing that air emissions from the facility have the potential to contribute to localized, modeled exceedances of the health-based NAAQS under certain unusual conditions. 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, respectively. On December 20, 2005, due to a determination by the DOE that an emergency situation exists with respect to a shortage of electric energy, the DOE ordered Mirant Potomac River to generate electricity at the Potomac River generation facility, as requested by PJM, during any period in which one or both of the transmission lines serving the central Washington, D.C. area 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. The DOE required Mirant Potomac River to submit a plan, on or before December 30, 2005, that met this requirement and did not significantly contribute to NAAQS exceedances. The DOE advised that it would consider Mirant Potomac River s plan in consultation with the EPA. 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 the rehearing requests further. 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 immediate operation of one baseload unit and two cycling units, making it possible to bring the entire plant into service within approximately 28 hours. The DOE s order expires after September 30, 2006, but we expect we 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 addresses NAAQS issues. The EPA also asserts 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 facility. The facility will not resume normal operations until it can satisfy the requirements of the Virginia DEQ and the EPA with respect to NAAQS, unless, for reliability purposes, it is required to return to operation by a governmental agency having jurisdiction to order its operation. On January 9, 2006, the FERC issued an order directing PJM and PEPCO to file a long-term plan to maintain adequate reliability in the Washington D.C. area and surrounding region and a plan to provide adequate reliability pending implementation of this long-term plan. On February 8, 2006, PJM and PEPCO filed their proposed reliability plans. We are working with the relevant state and federal agencies with the goal of restoring all five units of the facility to normal operation in 2007.

City of Alexandria Nuisance Suit. On October 7, 2005, the City of Alexandria filed a suit against Mirant Potomac River and Mirant Mid-Atlantic in the Circuit Court for the City of Alexandria. The suit asserts nuisance claims, alleging that the Potomac River plant s emissions of coal dust, fly ash, NOx, SO2, particulate matter, hydrogen chloride, hydrogen fluoride, mercury and oil pose a health risk to the surrounding community and harm property owned by the City. The City seeks injunctive relief, damages and attorneys fees. On February 17, 2006, the City amended its complaint to add additional allegations in support of its nuisance claims relating to noise and lighting, interruption of traffic flow by trains delivering coal to the Potomac River plant, particulate matter from the transport and storage of coal and flyash and potential coal leachate into the soil and groundwater from the coal pile.

Riverkeeper Suit Against Mirant Lovett. On March 11, 2005, Riverkeeper, Inc. filed suit against Mirant Lovett in the United States District Court for the Southern District of New York under the Clean Water Act. The suit alleges that Mirant Lovett s failure to implement a marine life exclusion system at its Lovett generating plant and to perform monitoring for the exclusion of certain aquatic organisms from the plant s cooling water intake structures violates Mirant Lovett s water discharge permit issued by the State of New York. The plaintiff requests the court to enjoin Mirant Lovett from continuing to operate the Lovett generating plant in a manner that allegedly violates the Clean Water Act, to impose civil penalties of $32,500 per day of violation, and to award the plaintiff attorney s fees. On April 20, 2005, the district court approved a stipulation agreed to by the plaintiff and Mirant Lovett that stays the suit until 60 days after entry of an order by the Bankruptcy Court confirming a plan of reorganization for Mirant Lovett becomes final and non-appealable.

Mirant Lovett Coal Ash Management Facility. On July 8, 2004, the New York State Department of Environmental Conservation (NYSDEC) issued an NOV for improper closure of the coal ash management facility (CAMF) at the Lovett plant. The Notice of Violation identified two separate issues. The first was the failure of the previous owner/operator of the CAMF to obtain a closure certification for Stage 1 of the CAMF that conformed with applicable New York regulations. It is our view that we have submitted documentation demonstrating that the CAMF was properly closed, however that issue is still in dispute. The second issue relates to the closure of Stage 2 of the CAMF in 2002. Erosion of the barrier protection layer and topsoil developed within a few years of the closure of Stage 2. On November 8, 2005, the NYSDEC issued an additional notice of violation to Mirant Lovett asserting that the leachate collection system for the Lovett CAMF was not properly constructed because it allows storm water or groundwater to come into contact with the disposed wastes and leachate. Due to the ongoing evaluation to determine what remedial actions are required, the exact cost of remedial action is unknown at this time.

New York Dissolved Oxygen. On September 29, 2003, the NYSDEC issued a complaint to Mirant New York for alleged failure to comply with state regulatory standards for minimum dissolved oxygen in the Mongaup River at the Swinging Bridge, Mongaup Falls and Rio hydroelectric projects owned by

Mirant NY-Gen. The complaint sought a civil penalty of $120,000 and an order requiring Mirant New York to upgrade the three hydroelectric projects to prevent further discharges that do not meet the standards for minimum dissolved oxygen. In its complaint the NYSDEC proposed that $100,000 of the $120,000 penalty it was seeking be suspended on the condition that Mirant New York complete corrective actions for each facility by a certain schedule it proposed. On June 1, 2004, Mirant New York filed an answer and motion to dismiss on grounds including that Mirant New York is not the owner of the hydroelectric projects. Mirant New York granted an extension of time to allow the NYSDEC to respond, and the NYSDEC has not yet responded. Mirant NY-Gen, the owner of the hydroelectric projects, has agreed with the NYSDEC upon a consent order to resolve the complaint. Under the consent order, Mirant NY-Gen will pay a fine of $8,000 and install certain specified equipment on the operational turbine at the Swinging Bridge facility. The specified equipment already has been installed on the Mongaup Falls and Rio facilities. In addition, Mirant NY-Gen is required to install this same equipment at the other, currently non-operational turbine at the Swinging Bridge facility within thirty days of that turbine becoming operational. The Bankruptcy Court approved the settlement on February 22, 2006, and the parties are proceeding to execute the consent order.

Mirant Bowline Oil Storage NOV. On January 4, 2006, the NYSDEC issued an NOV asserting various violations of regulations relating to a major oil storage facility, secondary containment, compliance report, underground storage tanks and a small oil storage facility at the Bowline plant. The NOV identified issues with labeling, maintenance and monitoring procedures and leak detection. The NOV did not seek a specific penalty amount but noted that the violations identified could each subject Mirant Bowline to a civil penalty of up to $37,500 per day. Mirant Bowline is working with the NYSDEC to address the issues identified.

Mirant Bowline Oil Spill. In November 2001, Mirant Bowline removed two underground oil storage tanks that had been used to collect oil recovered from the oil/water separators that are used for pretreatment of wastewater from the Bowline generating facility. Contaminated soil was found during the removal of one of the tanks and was removed from the site. Mirant Bowline is unable to confirm from documents at the facility whether the spill was reported to the NYSDEC and Rockland County, New York authorities. Consequently, Mirant Bowline reported a potential non-reported spill to the NYSDEC on February 23, 2006.

Morgantown Particulate Emissions. On March 3, 2006, Mirant Mid-Atlantic received a notice sent on behalf of the Maryland Department of the Environment (MDE) alleging that violations of particulate matter emissions limits applicable to Unit 1 at the Morgantown plant occurred on nineteen days in June and July 2005. The notice advises that the potential civil penalty is up to $25,000 per day for each day that Unit 1 exceeded the applicable particulate matter limit. The letter further advises that the MDE has asked the Maryland Attorney General to file a civil suit under Maryland law based upon the alleged violations.

City of Alexandria Zoning Action

On December 18, 2004, the City Council for the City of Alexandria, Virginia (the City Council) adopted certain zoning ordinance amendments recommended by the City Planning Commission that resulted in the zoning status of Mirant Potomac River s generating plant being changed from noncomplying use to nonconforming use subject to abatement. Under the nonconforming use status, unless Mirant Potomac River applies for and is granted a special use permit for the plant during the seven-year abatement period, the operation of the plant must be terminated within a seven-year period, and no alterations that directly prolong the life of the plant will be permitted during the seven-year period. If Mirant Potomac River were to apply for and receive a special use permit for the plant, the City Council would likely impose various conditions and stipulations as to the permitted use of the plant and to seek to limit the period for which it could continue to operate.

At its December 18, 2004, meeting, the City Council also approved revocation of two special use permits issued in 1989 (the 1989 SUPs), one applicable to the administrative office space at Mirant Potomac River s plant and the other for the plant s transportation management plan. Under the terms of the approved action, the revocation of the 1989 SUPs was to take effect 120 days after the City Council revocation, provided, however, that if Mirant Potomac River within such 120-day period filed an application for the necessary special use permits to bring the plant into compliance with the zoning ordinance provisions then in effect, the effective date of the revocation of the 1989 SUPs would be stayed until final decision by the City Council on such application. The approved action further provides that if such special use permit application is approved by the City Council, revocation of the 1989 SUPs will be dismissed as moot, and if the City Council does not approve the application, the revocation of the 1989 SUPs will become effective and the plant will be considered a nonconforming use subject to abatement.

On January 18, 2005, Mirant Potomac River and Mirant Mid-Atlantic filed a complaint against the City of Alexandria and the City Council in the Circuit Court for the City of Alexandria. The complaint seeks to overturn the actions taken by the City Council on December 18, 2004, changing the zoning status of Mirant Potomac River s generating plant and approving revocation of the 1989 SUPs, on the grounds that those actions violated federal, state and city laws. The complaint asserts, among other things, that the actions taken by the City Council constituted unlawful spot zoning, were arbitrary and capricious, constituted an unlawful attempt by the City Council to regulate emissions from the plant, and violated Mirant Potomac River s due process rights. Mirant Potomac River and Mirant Mid-Atlantic request the court to enjoin the City of Alexandria and the City Council from taking any enforcement action against Mirant Potomac River or from requiring it to obtain a special use permit for the continued operation of its generating plant. On January 18, 2006, the court issued an oral ruling following a trial that the City of Alexandria acted unreasonably and arbitrarily in changing the zoning status of Mirant Potomac River s generating plant and in revoking the 1989 SUPs. On February 24, 2006, the court entered judgment in favor of Mirant Potomac River and Mirant Mid-Atlantic declaring the change in the zoning status of Mirant Potomac River s generating plant adopted December 18, 2004 to be invalid and vacating the City Council s revocation of the 1989 SUPs.

Other Legal Matters

The Company is involved in various other claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Company s financial position, results of operations or cash flows.

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

None.

PART II

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

Common Stock

Prior to July 15, 2003, old Mirant s common stock was listed under, and traded on, the New York Stock Exchange (NYSE). As a result of old Mirant s bankruptcy filing on July 15, 2003, its common stock was suspended from trading by the NYSE and, thereafter, delisted by the NYSE. Old Mirant s stock was quoted in the Pink Sheets Electronic Quotation Service (Pink Sheets) maintained by Pink Sheets, LLC for the National Quotation Bureau, Inc. from July 16, 2003, until the emergence date of January 3, 2006. The ticker symbol MIRKQ was assigned to its common stock for over-the-counter quotations.

The following table sets forth the quarterly high and low bid quotations for old Mirant s common stock as reported on the Pink Sheets for 2004 and 2005. These quotations reflect inter-dealer prices, without retail markup, markdown or commissions, and may not necessarily represent actual transactions.

	Market	High	Low
2004			
First Quarter	Pink Sheets	$0.75	$0.40
Second Quarter	Pink Sheets	0.40	0.26
Third Quarter	Pink Sheets	0.48	0.30
Fourth Quarter	Pink Sheets	0.41	0.31
2005			
First Quarter	Pink Sheets	$0.48	$0.25
Second Quarter	Pink Sheets	0.51	0.29
Third Quarter	Pink Sheets	1.46	0.63
Fourth Quarter	Pink Sheets	1.51	1.16

Pursuant to the Plan, all shares of old Mirant s common stock were cancelled on January 3, 2006, and 276,500,000 shares of New Mirant common stock were distributed to holders of unsecured claims and equity securities. In addition, we reserved 23,500,000 shares for unresolved claims. New Mirant also issued two series of warrants, expiring January 3, 2011, that entitle their holders to initially purchase an aggregate of 52,941,177 shares of common stock. The Series A and Series B warrants entitle the holders to purchase an aggregate of 35,294,118 and 17,647,059 shares of common stock, respectively. The exercise price of the Series A and Series B warrants is $21.87 and $20.54 per share, respectively. New Mirant is authorized to issue 1,500,000,000 shares of common stock having a par value of $.01 per share and 100,000,000 shares of preferred stock having a par value of $.01 per share. As of March 3, 2006, there are 101,754 registered shareholders of New Mirant common stock.

Common stock of New Mirant is currently traded on the NYSE and has been assigned the ticker symbol MIR. Our Chief Executive Officer expects to provide a certification to the NYSE that he is not aware of any violation by us of the NYSE corporate governance listing standards. The high and low sales prices for our new common stock since listing on January 11, 2006, through March 3, 2006, are:

High	$29.00
Low	$23.93

All of New Mirant common stock was issued pursuant to the Plan in accordance with Section 1145 of the Bankruptcy Code and we received no proceeds from such issuance. The issuance of New Mirant shares of common stock was exempt from the registration requirements of the Securities Act of 1933, as amended, and equivalent provisions of state securities laws, in reliance upon Section 1145(a) of the Bankruptcy Code. As of March 3, 2006, there were 300,000,000 shares of the registrant s Common Stock, $0.01 par value per share outstanding.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table indicates the compensation plans under which equity securities of Mirant were authorized for issuance as of December 31, 2005:

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**Weighted-average exercise price of outstanding options, warrants and rights**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities to be issued upon exercise of outstanding options, warrants and rights)**
Equity compensation plans approved by security holders	12,996,209	$ 13.34	N/A (1)
Equity compensation plans not approved by security holders			
Total	12,996,209	$ 13.34	N/A (1)

(1) Pursuant to the Plan, these options were canceled on January 3, 2006.

Dividends

We will retain any future earnings to fund our operations and meet our cash and liquidity needs. We have not paid or declared any cash dividends on our common stock in the last two fiscal years and we do not anticipate paying any cash dividends on our common stock in the foreseeable future.

Item 6. *Selected Financial Data*

The following discussion should be read in conjunction with our consolidated financial statements and the notes thereto, which are included elsewhere in this Form 10-K. The following table presents our selected consolidated financial information, which is derived from our consolidated financial statements. The financial information for the periods prior to our separation from Southern Company on April 2, 2001, does not necessarily reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone entity during those periods.

From the Petition Date through emergence, our consolidated financial statements were prepared in accordance with Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code (SOP 90-7). Our Statement of Operations Data for the years ended December 31, 2004 and 2003 does not include interest expense on debt that was subject to compromise subsequent to the Petition Date. Our Statement of Operations Data for the year ended December 31, 2005, reflects the effects of accounting for the Plan of Reorganization confirmed on December 9, 2005.

The Consolidated Balance Sheet Data for years 2005, 2004 and 2003 segregates pre-petition liabilities subject to compromise from those liabilities that are not subject to compromise.

	Years Ended December 31, 2005	2004	2003	2002	2001
	(In millions except per share data)				
Statement of Operations Data:					
Operating revenues	$ 4,184	$ 4,571	$ 5,158	$ 4,697	$ 7,202
(Loss) income from continuing operations	(1,284)	(406)	(3,633)	(2,343)	462
Loss from discontinued operations	(7)	(70)	(173)	(95)	(53)
Cumulative effect of changes in accounting principles	(16)		(29)		
Net (loss) income	(1,307)	(476)	(3,835)	(2,438)	409
Pro forma earnings per share(1)	$ (4.36)	$ (1.59)	$ (12.78)	$ (8.13)	$ 1.36

(1) Calculated by dividing our net loss attributable to common shareholders by the 300 million common shares of New Mirant stock to be issued pursuant to the Plan.

	Years Ended December 31, 2005	2004	2003	2002	2001
Balance Sheet Data:					
Total assets	$ 12,912	$ 11,424	$ 12,123	$ 19,423	$ 22,043
Total long-term debt	3,701	1,375	1,538	8,822	8,435
Liabilities subject to compromise	18	9,217	9,077		
Company obligated mandatorily redeemable securities of a subsidiary holding solely parent company debentures				345	345
Stockholders equity (deficit)	3,856	(1,318)	(823)	2,955	5,258

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

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

Overview

We are an international energy company whose revenues are primarily generated through the production of electricity in the United States, Philippines and Caribbean. On July 14, 2003 (the Petition Date), and various dates thereafter, Mirant and 83 of its direct and indirect subsidiaries in the United States (collectively, the Mirant Debtors) filed with the United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division (the Bankruptcy Court) voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code (as amended the Bankruptcy Code). We continued to operate our business as a debtor-in-possession under the jurisdiction of the Bankruptcy Court in accordance with Chapter 11 of the Bankruptcy Code. As a result, our financial statements include the results of Bankruptcy Court bankruptcy process.

Our Plan of Reorganization (the Plan) was confirmed by the Bankruptcy Court on December 9, 2005, and we emerged from bankruptcy on January 3, 2006. As a result, we recorded the effects of the Plan in our financial statements for the year ended December 31, 2005. We recognized a gain of $283 million, included in reorganization items, net related to the effects of the Plan. Among other things we recognized the cancellation of old common stock, issuance of new common stock, reinstatement of certain debt and settlement amounts of claims, all as prescribed by the Plan. See Note 3 to our consolidated financial statements contained elsewhere in this report for additional discussion of the key elements of the Plan and the impacts of the Plan on our financial statements for the year ended December 31, 2005.

The primary factors impacting the earnings and cash flows of our United States operations are the prices for power, natural gas and coal, which are largely driven by supply and demand. The increase in new generation capacity that followed the restructuring of the power markets in the late 1990 s has created an oversupply situation in most markets which is expected to continue until 2008 to 2010. The imbalance between supply and demand, price controls during periods of high demand and local constraint and lack of appropriate compensation for locational capacity value limit our ability to recover our fixed costs such that we must rely almost entirely on energy gross margins produced by generating electrical energy for a price greater than the cost of the fuel required to run the plants. Demand for power can also vary regionally and seasonally due to, among other things, weather and general economic conditions. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation. We also are impacted by the relationship between prices for power and fuel, such as natural gas, coal and oil that impact our cost of generating electricity.

We engage in asset hedging activities to economically hedge our positions in order to reduce our exposure to commodity price fluctuations and to achieve acceptable gross margins. In general, we currently economically hedge a substantial portion of our Mid-Atlantic coal fired generation and our New England oil fired generation through over-the-counter transactions. However, we generally do not hedge most of our cycling and peaking capacity due to the limited value we can extract in the marketplace and the high cost of collateral typically required to support these contracts. Many of the power and fuel contracts that we use to economically hedge our portfolio meet the criteria of a derivative and are accounted for at fair value in our consolidated balance sheets. Changes in the fair value represent unrealized gains and losses and result in income volatility when the underlying energy prices are volatile.

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 operating permits. Our costs of complying with environmental laws, regulations and permits are substantial. We estimate that our capital expenditures for environmental compliance will be approximately $300 million for 2006 and will be $1 billion to $1.5 billion for 2006 through 2011. Our potential capital expenditures for environmental regulations are difficult to estimate because we cannot now assess what regulations may be applicable or what costs might be associated with the regulation. Our actual capital expenditures will be materially impacted if the State of Maryland passes legislation or imposes regulations that increase beyond applicable federal law the restrictions on emissions of SO_2, NO_x and mercury, or imposes restrictions on emissions of CO_2. This legislation or regulation, or similar legislation or regulation in other states or by the federal government, may render some of our units uneconomic.

A significant portion of our capital resources, in the form of cash and letters of credit is needed to satisfy counterparty collateral requirements. These counterparty collateral requirements reflect our non-investment grade credit ratings, volatile energy prices, generally higher margin levels in the industry and other factors. Whenever feasible, we seek to structure transactions in a way that reduces our potential liquidity needs for collateral.

Our Philippine operations include generating companies with long-term contracts, primarily with the Philippine government-owned NPC, which provide stable earnings and cash flow. Our core initiatives for our Philippine business include continuing to perform on our NPC contracts, managing regulatory, political and customer relationships and expanding our energy supply business from available, but uncontracted, generation capacity.

Our Caribbean operations include integrated utilities and generating companies with long-term contracts in cooperation with local governments. Our core initiatives for our Caribbean businesses include managing regulatory, political and customer relationships, reducing the system electricity losses at JPS as part of our continuous improvement efforts and adding additional generation capacity.

Consolidated Financial Performance

We reported operating income of $418 million for the year ended December 31, 2005, and operating losses of $14 million and $2,865 million for the years ended December 31, 2004 and 2003, respectively. The change in operating income is detailed as follows (dollars in millions):

	2005 versus 2004 Increase/(Decrease)		**2004 versus 2003 Increase/(Decrease)**	
Gross margin(1)	$ (198)	(10.1)%	$ (22)	(1.1)%
Operations and maintenance	13	1.3 %	82	7.6 %
Depreciation and amortization			32	9.4 %
Goodwill impairment losses(2)	582		1,485	71.8 %
Long-lived asset impairment losses(3)			1,339	
Other impairment losses and restructuring charges			34	59.6 %
Loss on sales of assets, net(4)	35	66.0 %	(99)	
Change in operating income	$ 432		$ 2,851	99.5 %

(1) For the years ended December 31, 2005, 2004 and 2003, our gross margin included the following (in millions):

	Years Ended December 31,					
	2005	**2004**	**Increase/ (Decrease)**	**2004**	**2003**	**Increase/ (Decrease)**
Realized gross margin	$ 1,762	$ 1,460	$ 302	$ 1,460	$ 1,674	$ (214)
Transition power agreement (TPA) amortization	9	344	(335)	344	426	(82)
Unrealized gross margin:						
Unrealized gains on Back-to-Back Agreement	98	168	(70)	168	171	(3)
Net unrealized losses on asset management and proprietary trading	(115)	(20)	(95)	(20)	(297)	277
Net unrealized gross margin	(17)	148	(165)	148	(126)	274
Total gross margin	$ 1,754	$ 1,952	$ (198)	$ 1,952	$ 1,974	$ (22)

(2) In 2004, we wrote off the remaining goodwill amounts related to our Philippine business of $582 million. In 2003, we wrote off all goodwill related to our United States business of $2,067 million. See Critical Accounting Policies and Estimates and Note 8 to our consolidated financial statements contained elsewhere in this report.

(3) In 2003, we had a long-lived asset impairment charge of $1,339 million related to turbines, power islands and other project costs. This asset impairment also caused depreciation and amortization expense to decrease in 2004 compared to 2003.

(4) Included in loss on sales of assets, net for 2005 is an $18 million loss related to the sale of assets at one of our suspended construction projects. In 2004, we had a loss on sales of assets, net of $65 million, primarily related to the planned sale of three natural gas combustion turbines offset by a gain of $16 million on the sale of our remaining Canadian natural gas transportation contracts and certain natural gas marketing contracts. In 2003, we had a gain on sale of assets of $46 million primarily related to the sale of gas storage contracts in our Canadian trading operations.

Bankruptcy Considerations

While in bankruptcy, our financial results were volatile as asset impairments, asset dispositions, restructuring activities, contract terminations and rejections, and claims assessments significantly impacted our consolidated financial statements. As a result, our historical financial performance is likely not indicative of our financial performance post-bankruptcy.

At December 31, 2005, we have accrued for disputed and contingent claims using our best estimate of the amount these claims will ultimately settle for. To the extent such claims are resolved post-emergence, the claimants will be paid on the same basis as if they had been paid out of the bankruptcy. That means that their allowed claims will be adjusted to the same recovery percentage as other creditors in the same class would have received and will be paid in pro rata distributions of cash and common stock in accordance with the terms of the Plan. It is our view that we have accrued the reserve at a sufficient level to settle the remaining unresolved claims. However, to the extent the aggregate amount of these payouts of contingent and disputed claims ultimately exceeds the amount of the claims reserve, we may be obligated to provide additional cash or stock to the claimants. This may also result in charges to future income or expense. For further discussion, see Critical Accounting Policies and Estimates.

Results of Operations

The following discussion of our performance is organized by reportable operating segment, which is consistent with the way we manage our business. Historically, we had managed our business as two operating segments: North America and International. In the fourth quarter of 2005, we began managing our business through the following three operating segments: United States, Philippines and Caribbean.

Beginning January 1, 2004, we changed our allocation methodology related to our corporate overhead expenses. As a result, substantially all of our corporate operating expenses are allocated to our United States, Philippines and Caribbean segments. The new methodology allocates costs using several methods but is primarily based on gross margin, property, plant and equipment balances and labor costs.

United States

Our United States segment consists primarily of electricity generation (approximately 14,000 MW of generating capacity) and energy trading and marketing activities managed as a combined business. The following table summarizes the operations of our United States segment for the years ended December 31, 2005, 2004, and 2003 (in millions):

	Years Ended December 31,					
	2005	2004	Increase/ (Decrease)	2004	2003	Increase/ (Decrease)
Gross margin	$ 971	$ 1,196	$ (225)	$ 1,196	$ 1,222	$ (26)
Operating expenses:						
Operations and maintenance	726	727	(1)	727	699	28
Depreciation and amortization	167	164	3	164	199	(35)
Goodwill impairment losses					2,067	(2,067)
Long-lived asset impairment losses					1,338	(1,338)
Impairment losses and restructuring charges	13	9	4	9	19	(10)
Loss (gain) on sales of assets, net	19	50	(31)	50	(38)	88
Total operating expenses	925	950	(25)	950	4,284	(3,334)
Operating income (loss)	$ 46	$ 246	$ (200)	$ 246	$ (3,062)	$ 3,308

In the tables below, the Mid-Atlantic region includes our Morgantown, Chalk Point Units 1-4, and Dickerson facilities. The Northeast region includes our New England and New York facilities. West and eliminations includes Mirant Texas, Mirant California and the elimination of intercompany transactions between Mirant Americas Generation subsidiaries that occurs at the Mirant Americas Generation level. Other United States generation includes Mirant Potomac River, LLC (Mirant Potomac River), Mirant Peaker, LLC (Mirant Peaker), Mirant Las Vegas, LLC (Mirant Las Vegas), Mirant Zeeland, West Georgia Generating Company, LLC (West Georgia), Mirant Sugar Creek, LLC (Mirant Sugar Creek) and Shady Hills Power Company, LLC (Shady Hills).

The following table summarizes capacity factor (average percentage of full capacity used over a year) by region for our United States segment for the years ended December 31, 2005, 2004 and 2003:

	Years Ended December 31,					
	2005	2004	Increase/ (Decrease)	2004	2003	Increase/ (Decrease)
Mirant Americas Generation:						
Mid-Atlantic	44 %	44 %	%	44 %	45 %	(1)%
Northeast	34 %	33 %	1 %	33 %	31 %	2 %
West	13 %	19 %	(6)%	19 %	9 %	10 %
Other United States generation	14 %	13 %	1 %	13 %	14 %	(1)%
Total United States	27 %	28 %	(1)%	28 %	23 %	5 %

The following table summarizes power generation volumes by region for our United States segment for the years ended December 31, 2005, 2004 and 2003 (in gigawatt hours):

	Years Ended December 31, 2005	2004	Increase/ (Decrease)	2004	2003	Increase/ (Decrease)
Mirant Americas Generation:						
Mid-Atlantic	16,572	16,463	109	16,463	16,884	(421)
Northeast	9,184	8,831	353	8,831	8,492	339
West	3,289	4,807	(1,518)	4,807	4,062	745
Other United States generation	5,032	4,815	217	4,815	5,637	(822)
Total United States	34,077	34,916	(839)	34,916	35,075	(159)

2005 versus 2004

Gross Margin. Our gross margin decreased by $225 million in 2005 compared to 2004. The following table details gross margin by realized and unrealized margin for the year ended December 31, 2005 and 2004 (in millions):

	Year Ended December 31, 2005 Realized	Unrealized	Total	Year Ended December 31, 2004 Realized	Unrealized	Total
Mirant Americas Generation:						
Mid-Atlantic	$ 478	$ (96)	$ 382	$ 499	$ (75)	$ 424
Northeast	225	(11)	214	218	31	249
West and eliminations	142		142	149	3	152
Total Mirant Americas Generation	845	(107)	738	866	(41)	825
Other United States generation	181	(1)	180	191	(21)	170
TPA amortization	9		9	344		344
Other, including TPAs and Back-to-Back Agreement	(47)	91	44	(353)	210	(143)
Total	$ 988	$ (17)	$ 971	$ 1,048	$ 148	$ 1,196

The following table summarizes the change in realized and unrealized gross margin for the year ended December 31, 2005 compared to same period in 2004 (in millions):

	Increase/(Decrease) for Years Ended December 31, 2005 versus 2004 Realized	Unrealized	Total
Mirant Americas Generation:			
Mid-Atlantic	$ (21)	$ (21)	$ (42)
Northeast	7	(42)	(35)
West and eliminations	(7)	(3)	(10)
Total Mirant Americas Generation	(21)	(66)	(87)
Other United States generation	(10)	20	10
TPA amortization	(335)		(335)
Other, including TPAs and Back-to-Back Agreement	306	(119)	187
Total	$ (60)	$ (165)	$ (225)

The $225 million decrease in gross margin is detailed as follows (in millions):

	Mid-Atlantic	Northeast	West and eliminations	Other Generation	TPA/Back-to-Back	Other	Total
Market prices-power	$ 518	$ 290	$	$ 84	$	$	$ 892
Market prices-fuel	(132)	(188)		(55)			(375)
Ancillary services	40	2		4			46
Generation volumes	(30)	(11)		(25			