DYNEGY INC /IL/
Form 10-K
February 27, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2006

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

For the transition period from to

Commission file number: 1-15659

DYNEGY INC.

(Exact name of registrant as specified in its charter)

Illinois	**74-2928353**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1000 Louisiana, Suite 5800

Houston, Texas 77002

(Address of principal executive offices)

(713) 507-6400

(Registrant s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Class A common stock, no par value	**New York Stock Exchange**

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

Title of each class
None

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

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 the filing requirements for the past 90 days. Yes x 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 registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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 ¨	Non-accelerated filer ¨

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

As of June 30, 2006, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $2,187,357,631 based on the closing sale price as reported on the New York Stock Exchange.

Number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date: Class A common stock, no par value per share, 401,210,616 shares outstanding as of February 22, 2007; Class B common stock, no par value per share, 96,891,014 shares outstanding as of February 22, 2007.

DOCUMENTS INCORPORATED BY REFERENCE. Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant s 2007 Annual Meeting of Shareholders, which the registrant intends to file not later than 120 days after December 31, 2006. However, if such Notice and Proxy Statement is not filed within such 120-day period, the Items comprising the Part III information will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period, pursuant to General Instruction G(3).

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PART I

DEFINITIONS

As used in this Form 10-K, the abbreviations contained herein have the meanings set forth in the glossary beginning on page F-72. Additionally, the terms Dynegy , we , us and our refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

Item 1. *Business*

THE COMPANY

Overview

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry and our primary business is the production and sale of electric energy, capacity and ancillary services from our 11,739 MW fleet (20 plants) of owned or leased power generation facilities.

Dynegy began operations in 1985 and became incorporated in the state of Illinois in 1999 in anticipation of our February 2000 acquisition of Illinova Corporation. Our principal executive office is located at 1000 Louisiana Street, Suite 5800, Houston, Texas 77002, and our telephone number at that office is (713) 507-6400.

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC s Public Reference Room at 100 F Street N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC s Public Reference Room. Our SEC filings are also available to the public at the SEC s web site at *www.sec.gov*. No information from such web site is incorporated by reference herein. Our SEC filings are also available free of charge on our web site at *www.dynegy.com*, as soon as reasonably practicable after those reports are filed with or furnished to the SEC. The contents of our website are not intended to be, and should not be considered to be, incorporated by reference into this Form 10-K.

On September 14, 2006, we entered into a Plan of Merger, Contribution and Sale Agreement (the Merger Agreement) with LSP Gen Investors, L.P., LS Power Partners, L.P., LS Power Equity Partners PIE I, L.P., LS Power Associates, L.P., and LS Power Equity Partners, L.P. (collectively, the LS Entities), part of the LS Power Group, a privately held power plant investor, developer and manager, to combine a portion of the LS Entities operating generation portfolio with our generation assets, and for us to acquire a 50 percent ownership interest in a development company that is currently controlled by the LS Entities. The combined company (New Dynegy) will have nearly 20,000 MW of generating capacity. Upon completion of the Merger Agreement, which is subject to the affirmative vote of holders of at least two-thirds of our Class A common stock and the satisfaction of other conditions, the combined company will own 29 operating power plants in 13 states (excludes the 351 MW Calcasieu generation facility which we have agreed to sell to Entergy Gulf States, Inc. (Entergy) employing a balanced mix of fuel sources with baseload, intermediate, and peaking dispatch capabilities, greater cash flow-generating opportunity than Dynegy alone, and significant scale and scope in three key geographic regions. The expanded portfolio will also include a controlling interest in the Plum Point facility, a 665 MW coal-fired plant currently under construction in Arkansas. Additionally, the development joint venture (referred to herein as the development company) will provide us with a 50 percent ownership interest in an established growth vehicle. The LS Entities current development activities include nine projects totaling more than 7,600 MW in various stages of development and approximately 2,300 MW of repowering and/or expansion opportunities.

If the transaction is consummated, the LS Entities will receive 340 million shares of New Dynegy s Class B common stock, $100 million in cash and $275 million aggregate principal amount of notes to be issued by

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New Dynegy. New Dynegy will also assume approximately $1.9 billion in net debt (debt less restricted cash and investments) from the LS Entities. Please read Note 3 Business Combinations and Acquisitions LS Power for further discussion of the terms of the Merger Agreement as well as the proxy statement/prospectus of Dynegy Acquisition, Inc. filed with the SEC on February 13, 2007.

General

Our assets are located in the Midwest, New York, Texas, Nevada and the Southeast. Our diverse power generation facilities generate electricity by burning coal, natural gas or oil. We sell electric energy, capacity and ancillary services by various means: (i) primarily through bilateral negotiated contracts with third parties and into regional central markets and (ii) with lesser volumes through structured wholesale over-the-counter markets and directly to end-use customers.

We are currently evaluating our portfolio in anticipation of consummating the LS Power transaction with the goal of focusing on regions and markets where we will have a significant asset position. This evaluation could result in sales of assets that are not considered strategic fits within our generating fleet. Our current generating facilities are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Baldwin	1,800	Coal	Baseload	Baldwin, IL	SERC (MISO)
Havana Units 1-5	228	Oil	Peaking	Havana, IL	SERC (MISO)
Unit 6	441	Coal	Baseload	Havana, IL	SERC (MISO)
Hennepin	293	Coal	Baseload	Hennepin, IL	SERC (MISO)
Oglesby	63	Gas	Peaking	Oglesby, IL	SERC (MISO)
Stallings	89	Gas	Peaking	Stallings, IL	SERC (MISO)
Tilton	188	Gas	Peaking	Tilton, IL	SERC (MISO)
Vermilion Units 1-2	164	Coal/Gas	Baseload	Oakwood, IL	SERC (MISO)
Unit 3	12	Oil	Peaking	Oakwood, IL	SERC (MISO)
Wood River Units 1-3	119	Gas	Peaking	Alton, IL	SERC (MISO)
Units 4-5	446	Coal	Baseload	Alton, IL	SERC (MISO)
Rocky Road	330	Gas	Peaking	East Dundee, IL	RFC (PJM)
Riverside/ Foothills	960	Gas	Peaking	Louisa, KY	RFC (PJM)
Rolling Hills	965	Gas	Peaking	Wilkesville, OH	RFC (PJM)
Renaissance	776	Gas	Peaking	Carson City, MI	RFC (MISO)
Bluegrass (2)	576	Gas	Peaking	Oldham Co., KY	SERC (LG&E)
Total Midwest	*7,450*				
Independence	1,064	Gas	Intermediate	Scriba, NY	NPCC (NYISO)
Roseton (3)	1,185	Gas/Oil	Intermediate	Newburgh, NY	NPCC (NYISO)
Danskammer Units1-2	123	Gas/Oil	Peaking	Newburgh, NY	NPCC (NYISO)
Units 3-4 (3)	370	Coal/Gas/Oil	Baseload	Newburgh, NY	NPCC (NYISO)
Total Northeast	*2,742*				

Calcasieu (4)	351	Gas	Peaking	Sulphur, LA	SERC
Heard County	539	Gas	Peaking	Heard Co., GA	SERC
Black Mountain (5)	43	Gas	Baseload	Las Vegas, NV	WECC
CoGen Lyondell	614	Gas	Baseload	Houston, TX	ERCOT (ISO)
Total South	*1,547*				
Total Fleet Capacity	*11,739*				

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(1) Unit capacity values are based on winter capacity.
(2) Effective September 1, 2006, Louisville Gas & Electric, and therefore Bluegrass, left the MISO market and resumed operation as a stand-alone control area.
(3) We lease the Roseton facility and units 3 and 4 of the Danskammer facility pursuant to a leveraged lease arrangement that is further described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Arrangements DNE Leveraged Lease beginning on page 50.
(4) On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval, the transaction is expected to close in early 2008. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Calcasieu on page F-20 for further discussion.
(5) We own a 50% interest in this facility and the remaining 50% interest is held by Chevron U.S.A., which we refer to as Chevron, our largest shareholder. Total output capacity of this facility is 85 MW.

We also have a CRM business which represents our legacy trading business. After the termination of the Sterlington tolling agreement on March 7, 2006, the CRM business primarily consists of the Kendall tolling agreement (excluding the Sithe toll which is in our GEN-NE segment and is an intercompany agreement), as well as our legacy gas, power and emissions trading positions. On September 14, 2006, we agreed to acquire the Kendall facility either through the planned acquisition of assets from the LS Entities or as a separate transaction. The Kendall tolling arrangement will become an intercompany obligation under our GEN-MW segment upon the closing of the transaction. We report the results of this business as a separate reportable segment.

Business Drivers in the Power Generation Industry

Profitability of our business is largely a function of the difference between market prices for electricity and our cost to produce electricity at our various facilities from which we sell some of our energy under longer-term contracts, either directly to our customers or through the over-the-counter wholesale energy markets. We sell the remaining production into the shorter-term and spot markets (otherwise called day-ahead and real-time markets). We also hedge a portion of the output from our facilities in the financial markets based on our perspective of market fundamentals.

Market Prices for Wholesale Power**.** Future market prices are driven by expectations of buyers and sellers as to the fundamental supply/demand balance, similar to many other commodity markets. Short-term power market prices are determined largely by the balance of supply and demand in a region and are heavily influenced by weather. Both short-term and long-term prices are also heavily impacted by the price of natural gas, which is also impacted by regional weather effects. At times in certain markets, power prices rise and fall in tandem with natural gas prices. In some markets in which we operate, there is an excess of power generation supply compared to demand. However, due to demand growth out-pacing supply growth, we expect that this excess supply will diminish over time as consumption continues to grow, likely resulting in increased market prices for power.

Summer and winter weather extremes can cause increased electricity consumption, driving up prices in affected regions. Conversely, during spring and fall when weather tends to be milder, market prices are usually less extreme.

In regions with centrally dispatched market structures (such as the Midwest and Northeast regions), all generators receive the same price for energy generated based on the price required to justify production of the last megawatt that is needed to balance supply with demand. For example, a less-efficient (i.e. more expensive) natural gas-fired unit may be needed in some hours to meet demand. If this unit s production is required to meet demand, its higher production costs will set the market clearing price that will be paid to all generators, regardless of the price that any other unit may have offered into the market or its cost of generation. In other regions, prices are determined on a bilateral basis between buyers and sellers.

Production Costs. Another key aspect of profitability is our cost to produce electricity. The main variable component of that cost is fuel. Our coal-fired generation facilities are our lowest cost facilities. Therefore, most

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of our coal-fired generation facilities run the majority of any given day throughout the year unless a particular unit is unavailable due to either planned or unplanned maintenance activity. In today s environment, our natural gas and oil fueled generation facilities are more expensive to operate than our coal-fired facilities. As a result, these plants only run on those days, or parts of days, when market demand and price are sufficient to economically justify dispatch of these higher cost units.

We also incur operations and maintenance (O&M) costs at our facilities. We categorize these costs as either fixed O&M or variable O&M. Fixed O&M is generally the non-fuel cost to maintain and operate a unit. This includes both major maintenance that must occur every few years to ensure reliability of a unit and routine maintenance, which must be performed more frequently. Variable O&M is the incremental cost that occurs for each dispatch, including fuel needed to start-up a unit and the cost of consumables used during operation.

Emissions Allowances. Operation of our power generation facilities is subject to regulatory limitations on emissions of both sulfur dioxide (SO_2) and nitrogen oxide (NO_X). We are granted emissions credit allowances by regulatory bodies on an annual basis. To the extent that our inventory of emissions allowances, including those that we carry forward from earlier years, are not sufficient to allow us to operate our plants within the emissions guidelines of the various air districts, we will either purchase additional emissions credits from third parties or reduce operation of that unit. Conversely, if we have more emissions credits on hand than are required to operate our facilities, we may opportunistically sell these credits, subject to certain regulatory limitations and restrictions contained in our DMG consent decree, or hold them in inventory until they are needed. Based on current projections, we do not expect a net expenditure from the purchase and sale of emissions allowances in the near term. Please read Regulatory and Environmental Matters Environmental, Health and Safety Matters Multi-Pollutant Air Emission Initiatives beginning on page 16 for a discussion of regulatory initiatives that will impact emissions over the longer term.

Services Provided. We sell electric energy, capacity and ancillary services from our facilities. Energy is the actual output of electricity that is measured in MWh at the wholesale level and is usually measured in KWh at the retail level. The capacity of a generation facility is its electricity production capability, measured in MW. Each NERC region must have sufficient generating capacity to meet expected consumption of electricity (known as load). Each NERC region calculates a reserve requirement, which is additional necessary capacity that a region must have in order to manage potential unit outages. Electricity consumers will, for reliability or regulatory reasons, contract for capacity from a capacity supplier from one or more of the generating units that the supplier owns. Ancillary services are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load.

We sell these components of electricity to our customers under short-term or long-term contractual agreements or tariffs. Most of the energy and capacity transactions that we enter into are based on industry standard contracts. We also sell into central markets operated by RTOs and ISOs. We enter into negotiated contracts for each product or a combination of products with other customers as well.

Customers. Our customers include RTOs and ISOs, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, industrial customers, power marketers, banks, hedge funds, other power generators and commercial end-users. We sell electric energy, capacity and ancillary services to some or all of these customers for various lengths of time. Some of our customers, such as municipalities or integrated utilities, purchase our products in order to serve their retail, commercial and industrial customers. Other customers, such as some power marketers, may buy from us to serve load or may purchase power as a hedge against other power sales that they have made, such that they are effectively a middle man between generators and end-users.

Dispatch Type. Our generation assets include baseload, peaking and intermediate dispatch types. Baseload generation is low-cost and economically attractive to dispatch around the clock throughout the year. A baseload facility is usually expected to run between 80%-90% of the hours in a given year. Intermediate generation is not

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as efficient and/or economic as baseload generation but is intended to dispatch to serve load during higher load times such as during daylight hours and sometimes on weekends. Peaking generation is the least efficient and highest cost generation and is generally dispatched to serve load during the highest load times such as hot summer and cold winter days. Our intermediate and peaking facilities are fueled by fuel oil or natural gas.

Capital Expenditures. Our capital expenditures are for the continued maintenance of our facilities to ensure their continued reliability and for investment in new equipment for either environmental compliance or increasing profitability. In 2006, we had approximately $148 million in capital expenditures for our entire fleet of generation assets, of which $90 million was for capital maintenance projects, $2 million was for development projects, primarily for the conversion of our Vermilion facility to PRB coal, and $56 million was for other environmental expenditures.

NERC Regions, RTOs and ISOs. In discussing our business, we often refer to NERC regions. The North American Electric Reliability Council (NERC) and its eight regional reliability councils (as of December 31, 2006) were formed to ensure the reliability and security of the electricity system. The regional reliability councils set standards for reliable operation and maintenance of power generation facilities and transmission systems. NERC reports seasonally and annually on generation and transmission status in each region.

Separately, RTOs and ISOs centrally operate markets and transmission across a regional footprint in some of the markets in which we operate. They are responsible for secure dispatch of all generation facilities in that footprint, and are responsible for both maximum utilization and efficiency of the transmission system within what have been determined to be secure levels. RTOs and ISOs administer electricity markets for physical and financial energy markets in the short term, usually day ahead and real-time markets. NERC regions and RTOs/ISOs often have different geographic footprints and while there may be physical overlap, their respective roles and responsibilities do not.

NERC Regions as of December 31, 2006

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Reliability. We seek to operate and maintain our generation fleet efficiently and safely, with an eye toward future maintenance and improvements, resulting in increased reliability. This increased reliability impacts our results to the extent that our generation units are available during times that it is economically sound to run. These efforts are reflected not only in capital improvements, but also in organizational and program changes.

Regulatory & Legislative Considerations

Our business is subject to extensive federal, state and local laws and regulations governing the generation and sale of electricity, the discharge of materials into the environment and otherwise relating to environmental, health and safety. Following is a summary of key regulatory and environmental considerations impacting our power generation operations. Please read Regulatory and Environmental Matters beginning on page 15 for further discussion of the environmental and regulatory restrictions applicable to our business.

Rates. Our wholesale power sales are governed by the FERC. With the exception of CoGen Lyondell and Black Mountain, which are Qualifying Facilities (QFs), all of our facilities currently have the authority to charge market-based rates for wholesale power. Many of our facilities also have cost-based tariffs for providing reactive power support. We are subject to FERC s regulations governing market behavior and prohibiting market manipulation, the violation of which could result in the revocation or suspension of our market-based rate authority as well as refunds, disgorgement of profits and monetary penalties.

Market Structure. Our sales of electricity and related services to particular customers and/or at a particular price are subject to the market structure and related rules in the states or regions where we operate. For instance, in organized markets like Texas, bids and prices are capped, and in the New York market, there is a price mitigation procedure to correct the adverse impact of errors or other activities outside the bounds of market rules and policies. In the state of Illinois, a resource procurement auction was recently conducted, resulting in the award of binding contracts between the utilities and wholesale energy providers such as Dynegy.

SO_2 and NO_X Emissions. The Clean Air Act and comparable state laws and regulations require that specified reductions in SO_2 and NO_X emissions be achieved. More recent regulations, including the Clean Air Interstate Rule (CAIR), require significant emissions reductions over the next several years. We have expended capital and installed emission control equipment at a number of our facilities to meet current requirements and expect to expend significant additional capital in the future to satisfy prospective requirements.

Mercury Emissions. The Clean Air Mercury Rule (CAMR), issued by the EPA in March 2005, requires that specified reductions in mercury emissions be achieved from the air emissions of coal-fired power plants. States are required to adopt the federal CAMR or a state rule meeting its minimum requirements. Both the states of Illinois and New York, where we have significant coal-fired assets, have recently adopted more stringent rules that will require greater reductions in emissions and thus could entail additional capital expenditures, in each case sooner than would CAMR. Our projected capital expenditures through 2013 include controls that we believe will achieve the new mercury emission reduction requirements. Additional capital expenditures may be required at our Wood River facility in 2015 depending on the performance of equipment installed between now and then.

Water Withdrawals. The Clean Water Act and comparable state laws and regulations require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The cooling water intake structures at four of our coal plants and one of our fuel oil plants in Illinois and New York are subject to this requirement. The scope of the requirement and the compliance methodologies allowed may become more restrictive, resulting in potentially significant increased costs. In addition, the timing for compliance may be adjusted.

Carbon Emissions. Our Northeast assets may become subject to a state-driven greenhouse gas emission reduction program known as the Regional Greenhouse Gas Initiative (RGGI). RGGI is a program under development by nine New England and Mid-Atlantic states to reduce carbon dioxide emissions from power

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plants. The state of New York has introduced, as a pre-proposal , a rule which would require affected generators to purchase 100 percent of the carbon credits needed to operate their facilities through an auction process. The final program requirements of RGGI and subsequent impact to our operations are not known at this time. The Northeast states currently intend to finalize carbon dioxide emissions requirements for electric generating facilities during 2007, with implementation to begin in 2009. Additional regulations are under consideration by various policy-making bodies and, if adopted, could impact our operations and require additional capital expenditures. Please read Note 18 Regulatory Issues on page F-53 for further discussion.

SEGMENT DISCUSSION

Our business operations are focused primarily on the wholesale power generation sector of the energy industry. We report the results of our power generation business based on geographical location and how we allocate resources as three separate segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW), (2) the Northeast segment (GEN-NE) and (3) the South segment (GEN-SO). We also separately report the results of our legacy CRM business, excluding the Sithe toll which is an intercompany agreement now and is included in GEN-NE. As described below, our NGL business, which was conducted through DMSLP and its subsidiaries, was sold to Targa Resources, Inc. (Targa) on October 31, 2005. Additionally, as described below, our former REG business, which was conducted through Illinois Power Company and its subsidiaries, was sold to Ameren Corporation on September 30, 2004. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest.

Power Generation Midwest Segment

Our Midwest fleet comprises 13 facilities located in Illinois (9 facilities), Michigan (1 facility), Ohio (1 facility) and Kentucky (2 facilities), with a total capacity of 7,450 MW. With the exception of our Bluegrass peaking facility in the LG&E control area, our Midwest fleet as of December 31, 2006 operates entirely within either the Midwest ISO (MISO) or the Pennsylvania-New Jersey-Maryland Interconnection (PJM). Key details of the Midwest fleet are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Baldwin	1,800	Coal	Baseload	Baldwin, IL	SERC (MISO)
Havana Units 1-5	228	Oil	Peaking	Havana, IL	SERC (MISO)
Unit 6	441	Coal	Baseload	Havana, IL	SERC (MISO)
Hennepin	293	Coal	Baseload	Hennepin, IL	SERC (MISO)
Oglesby	63	Gas	Peaking	Oglesby, IL	SERC (MISO)
Stallings	89	Gas	Peaking	Stallings, IL	SERC (MISO)
Tilton	188	Gas	Peaking	Tilton, IL	SERC (MISO)
Vermilion Units 1-2	164	Coal/Gas	Baseload	Oakwood, IL	SERC (MISO)
Unit 3	12	Oil	Peaking	Oakwood, IL	SERC (MISO)
Wood River Units 1-3	119	Gas	Peaking	Alton, IL	SERC (MISO)
Units 4-5	446	Coal	Baseload	Alton, IL	SERC (MISO)

Rocky Road	330	Gas	Peaking	East Dundee, IL	RFC (PJM)
Riverside/ Foothills	960	Gas	Peaking	Louisa, KY	RFC (PJM)
Rolling Hills	965	Gas	Peaking	Wilkesville, OH	RFC (PJM)
Renaissance	776	Gas	Peaking	Carson City, MI	RFC (MISO)
Bluegrass (2)	576	Gas	Peaking	Oldham Co., KY	SERC (LG&E)
Total Midwest	*7,450*				

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(1) Unit capacity values are based on winter capacity.
(2) Effective September 1, 2006, Louisville Gas & Electric, and therefore Bluegrass, left the MISO market and resumed operations as a stand-alone control area.

As of the beginning of 2006, all of our Midwest coal facilities had been converted to the use of PRB coal. PRB coal is a cleaner-burning coal with lower sulfur content, making it more economic to burn while emitting lower amounts of sulfur dioxide. These conversions and upgrades have enhanced reliability of the units, decreased emissions and lowered maintenance costs.

Midwest Fleet-MISO

At December 31, 2006, we owned nine generating facilities with an aggregate net generating capacity of 4,619 MW located within MISO. The MISO market includes all of Wisconsin and Michigan and portions of Ohio, Kentucky, Indiana, Illinois, Nebraska, Kansas, Missouri, Iowa, Minnesota, North Dakota, Montana and Manitoba, Canada.

All of our coal-fired generation in the Midwest is in the MISO market footprint, as is our Renaissance peaking facility. MISO s role is to ensure equal access to the transmission system and to maintain or improve electric system reliability in the Midwest. MISO was founded in 1996, and was specifically configured to comply with FERC s concept of an independent organization that will ensure the smooth regional flow of electricity in a competitive wholesale marketplace. MISO s primary objective is to direct traffic on the wholesale bulk electric power lines. In this role, MISO ensures that every electric industry participant has access to the lines and that no entity has the ability to deny access to a competitor. MISO also manages the use of the lines to make sure that they do not become overloaded. MISO operates physical and financial energy markets using a system known as Locational Marginal Pricing (LMP). This system calculates a price for every generator and load point within the MISO area. This system is price-transparent , allowing generators and load serving entities to see real-time price effects of transmission constraints and impacts of generation and load changes to prices at each point. MISO operates day-ahead and real-time markets into which generators can offer to provide energy. Financial Transmission Rights (FTRs) allow users to manage the cost of transmission congestion (the inability to physically move power from one location to another) and corresponding price differentials across the market area. MISO currently does not have a formal capacity market or ancillary services market. An independent market monitor is responsible for ensuring that MISO markets are operating properly and without manipulation. MISO has proposed an energy-only market design to meet resource adequacy (i.e., causing new generation to be built when needed). Market participants are currently debating this proposal, and the form and timeframe for implementation of a system other than an energy-only market are uncertain.

Contracted Capacity. Through our participation in the recent Illinois resource procurement auction, we entered into energy product supply agreements with subsidiaries of Ameren for the following products:

Up to 1,200 megawatts in each hour around the clock for the time period of January 1, 2007 through May 31, 2008, at the price of $64.77 per megawatt-hour; and

Up to 200 megawatts in each hour around the clock for the time period of January 1, 2007 through May 31, 2009, at the price of $64.75 per megawatt-hour.

Under the terms of these agreements, we expect to deliver electricity together with capacity and specified ancillary, transmission and load-following services necessary to serve a portion of Ameren s full-requirements residential and small customer load.

In addition to capacity committed under our contract with Ameren, we expect all of our remaining capacity in the MISO area of the region will be sold under other bilateral capacity contracts in 2007.

Illinois Resource Procurement Auction. In September 2006, the first reverse auction was concluded to procure power with delivery beginning in 2007. The ICC did not investigate the results of the Fixed Price

Auction segment, which covered substantially all of the retail needs for those customers taking fixed-price service from the largest electric utilities in Illinois (Commonwealth Edison Company and the three Ameren Illinois utilities: AmerenIP, AmerenCIPS and AmerenCILCO). Subsequent auctions would likely cover only a portion of the total retail needs of the utilities because of the use of staggered contracts for certain customer classes. The ICC did initiate an investigation into the Hourly Auction segment, and we have intervened in that proceeding.

There will continue to be challenges to the auction process. Numerous parties have appealed various aspects of the ICC Orders approving the auctions to the state intermediate appellate courts. Among others, the Governor and Attorney General (who has been an active party in the regulatory proceedings) have announced their opposition to the auctions and the Attorney General filed with the State Supreme Court for expedited review of the ICC s auction orders and a stay of the auction pending that review, which was denied. The appellate court cases have been consolidated and are in the briefing stage; we anticipate a ruling sometime in 2007, with the possibility of further review by the Illinois Supreme Court. In addition, at least one bill has been introduced in the Illinois General Assembly to extend the rate freeze previously in effect through the end of 2006, which may have an impact on Ameren s ability to meet its contractual obligations under the SFC s. There is also the possibility of additional political, legislative, judicial and/or regulatory actions over the next several months that could alter substantially the rights and obligations under or relating to the SFC s.

Environmental and Regulatory Considerations. In 2005, we settled a lawsuit filed by the U.S. EPA and the DOJ in the U.S. District Court for the Southern District of Illinois that alleged violations of the Clean Air Act and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating station. A consent decree was finalized in July 2005. The consent decree requires us to (i) pay a $9 million civil penalty; (ii) fund several environmental mitigation projects in the additional aggregate amount of $15 million; and (iii) install equipment in emission control projects at our Baldwin, Vermilion and Havana plants that we currently anticipate, based upon ongoing engineering estimates, will cost approximately $675 million through 2012.

Please read Regulatory and Environmental Matters beginning on page 15 for discussion of the environmental and regulatory restrictions applicable to our business.

Midwest Fleet-PJM

At December 31, 2006, we owned interests in three generating facilities, Rocky Road, Rolling Hills, and Riverside/Foothills, with an aggregate net generating capacity of 2,255 MW located within PJM. The majority of power generated by those facilities is sold to wholesale customers in the PJM market.

PJM currently administers markets for wholesale electricity and provides transmission planning for the region, utilizing the LMP system described above. PJM operates day-ahead and real-time markets into which generators can bid to provide electricity and ancillary services. PJM also administers markets for capacity. An independent market monitor continually monitors PJM markets for manipulation or improper behavior by any entity. In addition, FERC recently accepted PJM s proposed changes to its capacity markets (Reliability Pricing Model, or RPM), including establishing longer-term markets for capacity to improve market signals for new generation.

We sell substantially all of our capacity each year via the over-the-counter capacity market as well as through capacity auctions held by PJM. The remainder of capacity and energy is sold primarily into wholesale markets.

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Power Generation Northeast Segment

Our Northeast fleet comprises three facilities located in New York. We own the Independence power generating facility, and we operate two generating facilities, Roseton and Danskammer, under long-term lease arrangements. Our Roseton and Danskammer facility sites are adjacent and share common resources such as fuel handling, a docking terminal, personnel and systems. The combined generating capacity of our Northeast fleet is 2,742 MW.

Facility (1)	Total Net Generating Capacity (MW)(2)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Independence	1,064	Gas	Intermediate	Scriba, NY	NPCC (NYISO)
Roseton (3)	1,185	Gas/Oil	Intermediate	Newburgh, NY	NPCC (NYISO)
Danskammer Units1-2	123	Gas/Oil	Peaking	Newburgh, NY	NPCC (NYISO)
Units 3-4 (3)	370	Coal/Gas/Oil	Baseload	Newburgh, NY	NPCC (NYISO)
Total Northeast	*2,742*				

(1) Does not include the hydroelectric generation facilities acquired as part of our Sithe Energies acquisition. For further information, please see Note 10 Unconsolidated Investments Variable Interest Entities beginning on page F-34.
(2) Unit capacity values are based on winter capacity.
(3) We lease the Roseton facility and units 3 and 4 of the Danskammer facility pursuant to a leveraged lease arrangement that is further described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Arrangements DNE Leveraged Lease beginning on page 50.

Northeast Fleet-NYISO. All of our Northeast facilities are located in the New York Independent System Operator (NYISO) area. NYISO administers the state-wide transmission system and spot markets for electricity, calculates electricity prices, and dispatches generation using an LMP model. NYISO also administers markets for capacity and certain ancillary services. An independent market monitor continually monitors NYISO markets for manipulation or improper behavior by an entity. In 2003, NYISO implemented a Demand Curve mechanism for calculating pricing for installed capacity for three locational zones: New York City, Long Island, and the rest of the state of New York. Our facilities operate outside of New York City and Long Island. Capacity pricing is calculated as a function of NYISO s annual target reserve margin (18% for 2006-2007), the estimated cost of new entrant generation, estimated peak demand, and the actual amount of capacity bid into the market. The Demand Curve mechanism provides for incrementally higher capacity pricing at lower reserve margins, such that new entrant economics become attractive as the reserve margin approaches target levels. The intention of the Demand Curve mechanism is to ensure that existing generation has enough revenue to maintain operations when capacity revenues are coupled with energy and ancillary service revenues. Additionally, the Demand Curve mechanism is intended to attract new investment in generation in the locations in which it is needed most.

Due to transmission constraints, prices vary across the state and are generally higher in the Eastern part of New York, where our Roseton and Danskammer facilities are located, and in New York City. (Our Independence facility is located in the Northwest part of the state.) Current reserve margins of 24% are somewhat above the NYISO s target reserve margin of 18%. We believe that reserve margins are likely to return to target levels by 2009 to 2011.

Contracted Capacity. Approximately 70% of the Independence facility s capacity is obligated under a capacity sales agreement, which runs through 2014. Revenue from this capacity obligation is largely fixed with a variable discount that varies each month based on the price of power at Pleasant Valley LMP. Additionally, we supply steam from our Independence facility to a third party at a fixed yearly rate and supply up to 44 MW of

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fixed price energy to that third party under that agreement. For the uncommitted portion of our Northeast fleet, due to the standard capacity market operated by NYISO and liquid over-the-counter market for NYISO capacity products, we are able to sell substantially all of our capacity into the market each month. This provides for a steady stream of capacity revenues at market prices from our facilities both in the short-term and for the foreseeable future.

Environmental and Regulatory Considerations. Please read Regulatory and Environmental Matters beginning on page 15 for discussion of the environmental and regulatory restrictions applicable to our business.

Power Generation South Segment

Our South fleet comprises two natural gas-fired peaking facilities and two natural gas-fired cogeneration facilities totaling 1,547 MW of electric generating capacity. Key details of the South fleet are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Calcasieu (2)	351	Gas	Peaking	Sulphur, LA	SERC
Heard County	539	Gas	Peaking	Heard Co., GA	SERC
Black Mountain (3)	43	Gas	Baseload	Las Vegas, NV	WECC
CoGen Lyondell	614	Gas	Baseload	Houston, TX	ERCOT (ISO)
Total South	*1,547*				

(1) Unit capacity values are based on winter capacity.

(2) On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval, the transaction is expected to close in early 2008. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Calcasieu on page F-20 for further discussion.

(3) We own a 50% interest in this facility and the remaining 50% interest is held by Chevron. Total generating capacity of this facility is 85 MW.

South Fleet-SERC

Our Calcasieu and Heard County facilities are located in SERC. SERC territory includes all or portions of the states of Illinois, Missouri, Kentucky, Arkansas, Tennessee, West Virginia, Virginia, North Carolina, South Carolina, Louisiana, Mississippi, Alabama and Georgia.

Our South Fleet SERC assets are located within control areas of vertically integrated utilities and municipalities. All power sales and purchases are consummated between individual parties and are physically delivered either within or across control areas of the transmission owners. The present market framework in SERC is not a centralized market, and it is not expected that this region will transition to centralized competitive markets for energy and capacity in the foreseeable future.

The SERC region currently has surplus generation capacity, resulting from past competition among merchant plant developers, significantly exceeding SERC s estimated target reserve margin of approximately 15% to 17%. The overcapacity is concentrated in the Entergy and Southern sub-regions of SERC (where the Calcasieu and Heard County facilities are located). This overcapacity has historically depressed energy and capacity values in this region; this influence may continue until demand growth absorbs excess supply.

On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval, the transaction is expected to close in early 2008. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Calcasieu on page F-20 for further discussion.

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Contracted Capacity. Given the Southeast s regulated market structure, these two plants principally sell capacity to the local regulated utilities and energy and ancillary services through bilateral transactions with the utilities and wholesale buyers.

South Fleet-ERCOT

Our CoGen Lyondell facility is located in ERCOT, which comprises a majority of the state of Texas.

This market is administered by ERCOT ISO, which oversees competitive wholesale and retail markets. ERCOT s operations are overseen by the PUCT. ERCOT operates as the single control area within its region and operates energy markets for market participants. Price mitigation measures in ERCOT include a $1,000 per MWh offer cap. ERCOT is considering wholesale market design changes including LMP (similar to markets in MISO, NYISO and PJM) in response to a PUCT rule. Implementation details and timing of these market changes have not yet been finalized, but are expected in approximately 2009.

The ERCOT region currently has surplus generation capacity indicated by a NERC estimated 2006 reserve margin of 14%, exceeding ERCOT s target minimum reserve margin of 12.5%. This overcapacity has historically depressed energy and capacity values in this region. However, previously released reports from ERCOT indicate that reserve margins may fall below the 12.5% level by 2010 to 2013 due to announced generating retirements and mothballed units.

Contracted Capacity. Since its inception, the CoGen Lyondell facility has sold steam and 70 MW of capacity and energy to its site host, Lyondell Chemical Company, under long-term contracts which expired in December 2006. The steam and energy sales contracts were amended and extended beginning January 1, 2007. We sell up to 80 MW of capacity and energy and 1.5 million pounds per hour of steam for a base contract term from January 2007 through December 2021 and subsequent automatic rollover terms of two years each thereafter through as long as December 2046.

The balance of Cogen Lyondell s capacity and energy (approximately 534 MW) are sold through bilateral transactions or through the ERCOT daily market.

Environmental and Regulatory Considerations. During 2006, the Cogen Lyondell facility installed NO_x emissions reduction controls, at a cost of approximately $15 million, to satisfy Houston-area ozone rules. When the project is completed in 2007, at a total cost of approximately $23 million including interest on construction, the facility is expected to be in environmental compliance for the foreseeable future.

Please read Regulatory and Environmental Matters beginning on page 15 for further discussion of the environmental and regulatory restrictions applicable to our business.

South Fleet Equity Investments

Black Mountain. Our Black Mountain plant is a PURPA QF located near Las Vegas, Nevada, in the WECC. Capacity and energy from this facility are sold to Nevada Power Company under a long-term PURPA QF contract.

Customer Risk Management

After the termination of the Sterlington tolling agreement on March 7, 2006, the CRM business primarily consists of a remaining power tolling arrangement relating to the Kendall facility, as well as our legacy physical natural gas supply contracts, natural gas transportation contracts and natural gas, power and emissions trading positions. A tolling arrangement is a contract whereby a generation owner sells rights to dispatch the unit at a defined heat rate and for terms and conditions provided for in the agreement while the owner continues to operate the facility. The buyer under a tolling arrangement generally provides fuel in accordance with dispatch instructions for the unit.

We mitigated the effect of the Kendall tolling arrangement through November 2008 by entering into a back-to-back power purchase agreement with a subsidiary of Constellation Energy Commodities Group, Inc. (Constellation), under which we receive payments which offset our obligations to the owner of the facility. Pursuant to this arrangement, we are obligated to make aggregate payments of approximately $416 million to the owner of the facility in exchange for access to power generated by the facility, resulting in a total obligation of $335 million, net of $81 million to be received from Constellation over the next 23 months. On September 14, 2006, we agreed to acquire the Kendall facility either through the planned acquisition of assets from the LS Entities or as a separate transaction. The Kendall tolling arrangement will become an intercompany obligation under our GEN-MW segment upon the closing of the transaction. As a result, the impact of the toll in the consolidated financial statements would be eliminated in consolidated results.

Legacy Marketing and Trading. Regarding our legacy natural gas, power and emission businesses, we have substantially reduced the size of our mark-to-market portfolio since October 2002, when we initiated our efforts to exit the CRM business.

Natural Gas We have exited a significant portion of our physical and financial natural gas marketing and trading business and expect to have substantially exited this business by the end of 2007, with the exception of a minimal number of physical natural gas transactions that expire between 2010 and 2017. Many of our remaining transactions relate to the sale of natural gas to power plants, municipalities, and other industrial users in various regions across the U.S. along with financial contracts that hedge the price exposure inherent in those contracts. These remaining transactions still require cash payments to purchase natural gas for our customers; however, those cash requirements are partially offset by the proceeds received from financial contracts hedging the supply. We will continue our efforts to exit the remaining transactions as allowed by market liquidity, credit requirements, and market opportunities.

Power We have substantially exited our remaining CRM power business, exclusive of the remaining power tolling arrangement in the segment with the exception of a minimum number of positions that will remain until 2010. These transactions primarily relate to past trading activity that was conducted in prior years for periods that have yet to mature. These transactions are accounted for on a mark-to-market basis and will continue to result in volatility in our statement of operations as prices change during the year. We will continue our efforts to exit the remaining transactions as allowed by market liquidity, credit requirements, and market opportunities.

Emissions We have a forward obligation to deliver SO_2 emissions allowances through 2008. Our financial statements reflect the gain or loss on this obligation resulting from the price fluctuation in SO_2 emissions allowances. This obligation will be satisfied by our current inventory of physical SO_2 emissions allowances, and such inventory is valued at the lower of cost or market, in accordance with GAAP. Upon settlement of the forward obligation, we will recognize a gain to the extent that the delivery price is higher than the book value of our inventory. Upon delivery of the emissions allowances, we expect a positive cash flow as the third party makes payment for the emissions allowances. The inventory of emissions allowances that we use to fulfill this forward obligation is separate from the inventory and needs of our power generation business.

Other

Corporate

Other also includes corporate governance roles and functions, which are managed on a consolidated basis, and specialized support functions such as finance, accounting, risk control, tax, legal, human resources, administration and information technology. Corporate general and administrative expenses, income taxes and interest expenses, except for interest on borrowings incurred by our operating segments, are also included, as are

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corporate-related other income and expense items. Results for our discontinued global communications business are also included in this segment in periods where appropriate.

Natural Gas Liquids

Our natural gas liquids segment consisted of our midstream asset operations, located principally in Texas, Louisiana and New Mexico, and our North American natural gas liquids marketing business, all of which we sold in October 2005. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids beginning on page F-23 for further discussion.

Regulated Energy Delivery

Our regulated energy delivery segment consisted of our former Illinois Power Company subsidiary, which we sold in September 2004. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-21 for further discussion.

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REGULATORY AND ENVIRONMENTAL MATTERS

Our business is subject to extensive federal, state and local laws and regulations governing the generation and sale of electricity.

Federal. Our ability to charge market-based rates for electricity, as opposed to cost-based rates, is governed by the FERC. We have been granted market-based rate authority for wholesale power sales from our exempt wholesale generator facilities, which include all of our facilities except CoGen Lyondell and Black Mountain. These two facilities are Qualifying Facilities, which have various exemptions from federal regulation and sell electricity directly to purchasers under power purchase agreements. Our market-based rate authority is predicated on FERC not finding the existence of market power for our facilities with market-based rates, and our next triennial market power review is currently scheduled for filing with the FERC in mid-2008. The FERC has adopted market behavior rules and regulations designed to prohibit energy market manipulation. A violation of these regulations could result in the revocation or suspension of our market-based rate authority, as well as refunds, disgorgement of profits and potential monetary penalties. Please read Note 18 Regulatory Issues beginning on page F-53 for further discussion.

State. Our business also is subject to regulation in the states where we operate. Proposed reforms to these regulations are pending in several states, including Illinois and New York. Please read Segment Discussion beginning on page 7 for further discussion of these state regulations by segment.

Environmental, Health and Safety Matters

Our business is subject to extensive federal, state and local laws and regulations governing discharge of materials into the environment or otherwise relating to environmental, health and safety protection for our employees and communities. We are committed to operating within these regulations and to conducting our business in a safe and environmentally responsible manner. The regulatory landscape is subject to change and has become more stringent over time. Failure to acquire or maintain permits or to otherwise comply with applicable rules and regulations may result in fines and penalties. Additionally, the process for acquiring or maintaining permits or otherwise complying with applicable rules and regulations may require unprofitable or unfavorable operating conditions or significant capital and operating expenditures.

Our aggregate expenditures (both capital and operating) for compliance with laws and regulations related to the protection of the environment associated with our power generation fleet were approximately $60 million in 2006, compared to approximately $56 million in 2005 and approximately $25 million in 2004. The 2006 expenditures include approximately $21 million for consent decree projects and $8 million associated with the conversion of our Vermilion and Havana facilities to PRB coal, compared to $27 million in 2005 for the PRB coal conversion projects. We estimate that total environmental expenditures (both capital and operating) in 2007 will be approximately $110 million, including approximately $90 million for consent decree projects and approximately $15 million for O&M. These 2007 expenditures do not include approximately $10 million for several environmental mitigation projects that are also part of the DMG consent decree or amounts assumed as a result of the proposed Merger Agreement with the LS Entities. In 2007, the projected costs are associated primarily with enhanced air pollution controls and handling of combustion byproducts. Changes in environmental regulations or outcomes of litigation, the ongoing appeal of the New York State Pollution Discharge Elimination System (SPDES) Permit issued to Danskammer in June 2006 and the SPDES Permit renewal proceeding involving Roseton, could result in additional requirements that would necessitate increased future spending and potentially adverse operating conditions.

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Ongoing and Future Environmental Initiatives. Current and proposed legislation and rulemaking contain requirements for further environmental control that we expect may result in substantial capital investments and operational costs. Sources of these ongoing and potential future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on SO_2, NO_X and mercury emissions from coal-fired power plants;
- Clean Air Act requirements relating to air emissions, construction and operating permits and compliance certifications;
- Clean Water Act requirements to reduce impacts of water intake structures on aquatic species at certain of our power plants;
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global warming; and
- The State of New York s consideration of a New Source Review rule that is more restrictive than the Federal New Source Review program, as it relates to routine maintenance, repair and replacement activities.

Following is a description of reasonably anticipated environmental initiatives for which we could incur significant expenditures, depending on the outcome.

Multi-Pollutant Air Emission Initiatives. In recent years, various federal and state legislative and regulatory multi-pollutant initiatives have been introduced. In early 2005, the EPA finalized several rules that would collectively require reductions of approximately 70% each in emissions of SO_2, NO_X and mercury from coal-fired electric generating units by 2015 (2018 for mercury).

The Clean Air Interstate Rule (CAIR) is intended to reduce SO_2 and NO_X emissions across the eastern United States (29 states and the District of Columbia) and address fine particulate matter and ground-level ozone National Ambient Air Quality Standards. The rule includes both seasonal and annual NO_X control programs as well as an annual SO_2 control program. A majority of our generating facilities will be subject to these programs. The compliance deadline for Phase I for the NO_X control program is in 2009; the SO_2 control program becomes effective in 2010. The final compliance phase begins in 2015. In April 2006, the U.S. EPA Administrator published a final rule that includes a federal implementation plan (FIP) to reduce transport of fine particulate matter and ozone. States may choose to develop their own NO_X requirements, within their respective state implementation plans, at least as stringent as the FIP, else the EPA will apply the FIP requirements to these states. Participation by states in the CAIR regional trading program is not mandatory.

The CAIR rule establishes a cap-and-trade program projected to reduce NO_X and SO_2 emissions by 61 percent and 73 percent, respectively, by 2018 and requires states to achieve the required reductions by adopting CAIR or state rules. The Illinois EPA has proposed a rule to implement the CAIR requirements that would require greater reductions in NO_X emissions from electric generators by setting aside 30 percent of the available NO_X emission allowances for energy efficiency and conservation projects, making the allowances unavailable to generators.

The U.S. EPA issued the Clean Air Mercury Rule (CAMR) for control of mercury emissions in March 2005 and, in December 2006, promulgated a backstop plan to ensure that power plants affected by the CAMR reduce their mercury emissions on schedule. CAMR establishes a cap-and-trade program that would reduce emissions of mercury from coal-fired power plants and, according to the EPA, the rule will reduce utility emissions of mercury from 48 tons per year to 15 tons per year by 2018, a reduction of nearly 70 percent from 1999 emission levels. The federal rule requires states to promulgate rules at least as stringent as CAMR. In December 2006 the Illinois Pollution Control Board approved a state rule that would require greater mercury emissions reductions and in a shorter time period than CAMR. The Illinois Rule will require additional capital and O&M expenditures at each of our Illinois coal-fired plants beginning in 2007. The state of New York has also approved a mercury rule that is more stringent than CAMR, and will likely require additional capital and operating costs.

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We initially opposed the Illinois mercury rule because the schedule for implementation was considered impractical. In settling our opposition to the rule, we agreed to join with the Illinois Environmental Protection Agency in advancing a revised regulatory proposal that would significantly reduce mercury emissions but allow sufficient time to meet the emission limitation while making further reductions in emissions of sulfur dioxide, nitrogen oxides and particulate matter from the company s generation facilities. The rule approved by the Illinois Pollution Control Board in December 2006 included the revised proposal covering multiple pollutants, including mercury, NO_X and SO_2.

The Clean Air Visibility Rule (CAVR) addresses the requirement for states to analyze and include Best Available Retrofit Technology (BART) requirements for individual facilities in their state implementation plans to address regional haze, which rules are due by the end of 2008 with compliance expected five years later. The requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. The record for the final rule contains an analysis that demonstrates that for electric generating units subject to CAIR, CAIR will generally result in more visibility improvements than BART would provide. Therefore, it may prove sufficient for states that adopt CAIR to substitute its requirements for BART controls otherwise required by SIPs under CAVR. In preparing their SIPs, states are required to do so in tandem with the recommendation of their state environmental Regional Planning Organizations, which may be more stringent than CAIR.

The Clean Air Act. The Clean Air Act and comparable state laws and regulations relating to air emissions impose responsibilities on owners and operators of sources of air emissions, including requirements to obtain construction and operating permits as well as compliance certifications and reporting obligations. The Clean Air Act requires that fossil-fueled plants have sufficient SO_2 and, in some regions NO_X emission allowances, as well as meet certain pollutant emission standards. Our electric generation facilities, some of which have changed their operations to accommodate new control equipment or changes in fuel mix, are presently in compliance with these requirements. In order to ensure continued compliance with the Clean Air Act and related rules and regulations, including ozone-related requirements, we have plans to install emission reduction technology and expect to incur a total capital expenditure of up to $7 million in 2007 pursuant to such plans.

Water Issues. Our water withdrawals and wastewater discharges are permitted under the Clean Water Act and analogous state laws. Section 316(b) of the Clean Water Act and comparable state water laws and regulations, require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact. The cooling water intake structures at four of our coal and one of our fuel oil-fired facilities in Illinois and New York are subject to this requirement.

The U.S. EPA issued rules in July 2004 establishing national standards aimed at protecting aquatic life at power generating facilities with existing cooling water intake structures. The rule requires a Comprehensive Demonstration Study (CDS) for each affected facility to provide information needed to determine necessary facility-specific modifications and cost estimates for implementation. The required studies are either underway or complete at all of the affected facilities, and the rule requires that final compliance plans be in place by January 2008. Once compliance measures are determined and approved by regulators, a facility may have several years to implement the measures. Due to the wide range of measures potentially applicable to a given facility, and since the final selection of compliance measures will be at least partially dependent upon the CDS information, we are not able to estimate our total fleet cost for complying with the rule at this time.

On January 25, 2007, the United States Court of Appeals for the Second Circuit remanded to the EPA a substantive portion of these rules, including EPA s determination of BTA for existing water intake structures. The Court s remand of the rule to EPA has created uncertainty concerning the performance standard and the schedule for implementing the requirement. Further appellate review of the rule may be pursued or EPA may revise the rule in accordance with the Court s opinion. The scope of requirements and the compliance methodologies allowed may become more restrictive, resulting in potentially significantly increased costs. In addition, the timing for compliance may be adjusted.

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As with air quality, the requirements applicable to water quality are expected to increase in the future. A number of efforts are under way within the EPA to evaluate water quality criteria for parameters associated with the by-products of fossil fuel combustion. These parameters include arsenic, mercury and selenium. Significant changes in these criteria could impact discharge limits and could require our facilities to install additional water treatment equipment.

We are currently involved in an administrative proceeding in New York relating to the permit governing the cooling water intake structure at our Roseton facility. If the proceeding is resolved unfavorably to us, we could be required to expend material capital or to reduce plant operations. We have recently successfully completed similar administrative proceedings concerning our Danskammer facility resulting in a new permit Challenges to the new Danskammer permit by environmental groups that participated in the proceeding could result in material capital expenditures or reduced plant operations. For further discussion of these matters, please see Note 17 Commitments and Contingencies Danskammer State Pollutant Discharge Elimination System Permit beginning on page F-48 and Note 17 Commitments and Contingencies Roseton State Pollutant Discharge Elimination System Permit beginning on page F-49, respectively.

Global Climate Change. The international treaty relating to global warming (commonly known as the Kyoto Protocol) would have required reductions in emissions of greenhouse gases, primarily carbon dioxide and methane, by industry, including power generating facilities, if ratified by the United States. As an alternative to Kyoto, which became effective (without ratification by the United States) in February 2005, current U.S. policy regarding greenhouse gases favors voluntary reductions, increased operating efficiency, and continued research and technology development. Although several bills have been introduced in Congress that would compel reductions in carbon dioxide emissions, there are presently no federal mandatory greenhouse gas reduction requirements. The likelihood of any federal mandatory carbon dioxide emissions reduction program being adopted in the near future, and the specific requirements of any such program, is uncertain. However, a number of states where we operate power generation facilities in the Northeast and Midwest have proposed or are in the process of developing regulatory programs to manage greenhouse gas emissions. Please read Multi-Pollutant Air Emission Initiatives above for further discussion.

Any adoption by the federal or state governments of programs mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. Although we cannot predict the potential impact of such laws or regulations on our future financial condition, results of operations or cash flows, we will continue to monitor and participate in greenhouse gas policy developments in the regions in which we operate and will continue to assess and respond to the potential impact on our business operations.

Regional Greenhouse Gas Initiative. RGGI is a program under development by nine New England and Mid-Atlantic states to reduce carbon dioxide emissions from power plants through a cap and trade program. The state of New York has introduced, as a pre-proposal , a rule that would require any fossil fuel fired electric generator larger than 25 MW to hold CO_2 emission allowances in the amount of its annual CO_2 emissions. The state would auction CO_2 emission allowances annually. The CO_2 emission allowances available for purchase by generators would be capped at approximately 64 million tons of CO_2 emissions. Affected generators would be required to purchase 100 percent of the carbon credits needed to operate their facilities through the auction process. The final program requirements of RGGI and subsequent impact to our operations are not known at this time, but the Northeast states currently intend to finalize carbon dioxide emissions requirements for electric generating facilities within the next few months.

Remedial Laws. We are also subject to environmental requirements relating to handling and disposal of toxic and hazardous materials, including provisions of CERCLA and RCRA and similar state laws. CERCLA imposes strict liability on persons that contributed to release of a hazardous substance into the environment. These persons include the current or previous owner and operator of a facility and companies that disposed, or arranged for disposal, of hazardous substances found at a contaminated facility. CERCLA also authorizes the

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EPA and, in some cases, private parties to take actions in response to threats to public health or the environment and to seek recovery for costs of cleaning up hazardous substances that have been released and for damages to natural resources from responsible parties. Further, it is not uncommon for neighboring landowners and other affected parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. CERCLA or RCRA could impose remedial obligations at a variety of our facilities.

Additionally, the EPA may develop new regulations that impose additional requirements on facilities that store or dispose of non-hazardous fossil fuel combustion materials, including coal ash. If so, we and other similarly situated power generators may be required to change current waste management practices and incur additional capital expenditures to comply with these regulations.

As a result of their age, a number of our facilities contain quantities of asbestos-containing materials, lead-based paint, and/or other regulated materials. Existing state and federal rules require the proper management and disposal of these materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations and removal and abatement of asbestos-containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself.

Health and Safety Rules. Our operations are subject to requirements of the Occupational Safety and Health Administration (OSHA) and other comparable federal, state and provincial statutes. We have processes in place to identify and evaluate risk in order to ensure that non-compliances are detected and corrected in a timely manner. We believe we currently comply and expect to continue to comply in all material respects with applicable rules and regulations.

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COMPETITION

Demand for power may be met by generation capacity based on several competing technologies, such as natural gas-fired, coal-fired or nuclear generation, as well as power generating facilities fueled by alternative energy sources, including hydro power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Our power generation businesses in the Midwest, Northeast, and South compete with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities and other energy service companies. We believe that our ability to compete effectively in these businesses will be driven in large part by our ability to achieve and maintain a low cost of production, primarily by managing fuel costs, and to provide reliable service to our customers. We believe our primary competitors consist of at least 15 companies in the power generation business.

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OPERATIONAL RISKS AND INSURANCE

We are subject to all risks inherent in the power generation business. These risks include, but are not limited to, equipment breakdowns or malfunctions, explosions, fires, terrorist attacks, product spillage, weather including hurricanes and tornados, nature including earthquakes and inadequate maintenance of rights-of-way, which could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or pollution of the environment, as well as curtailment or suspension of operations at the affected facility. We maintain general public liability, property/boiler and machinery, and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles and caps that we consider reasonable and not excessive given the current insurance market environment. The costs associated with these insurance coverages have been volatile during recent periods, and may continue to be so in the future. The occurrence of a significant event not fully insured or indemnified against by a third party, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our potential inability to secure these levels and types of insurance in the future could negatively impact our business operations and financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates we consider commercially reasonable.

We also face market, price, credit and other risks relative to our business. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 81 for further discussion of these risks.

In addition to these operational risks, we also face the risk of damage to our reputation and financial loss as a result of inadequate or failed internal processes and systems. A systems failure or failure to enter a transaction properly into our records and systems may result in an inability to settle a transaction in a timely manner or cause a contract breach. Our inability to implement the policies and procedures that we have developed to minimize these risks could increase our potential exposure to damage to our reputation and to financial loss. Please read Item 9A. Controls and Procedures beginning on page 84 for further discussion of our internal control systems.

SIGNIFICANT CUSTOMERS

For the year ended December 31, 2006, approximately 23%, 19% and 18% of our consolidated revenues were derived from transactions with AmerenIP, MISO and NYISO, respectively. For the year ended December 31, 2005, approximately 26% and 20% of our consolidated revenues were derived from transactions with NYISO and AmerenIP, respectively. For the year ended December 31, 2004, approximately 13% of our consolidated revenues were derived from transactions with NYISO. No other customer accounted for more than 10% of our consolidated revenues during 2006, 2005 or 2004.

EMPLOYEES

At December 31, 2006, we had approximately 348 employees at our administrative offices and approximately 991 employees at our operating facilities. Approximately 640 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions that expire in June 2007 (Midwest) and in February 2008 (Northeast). We believe relations with our employees are satisfactory.

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

Forward-Looking Statements

This Form 10-K includes statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as forward-looking statements . All statements included or incorporated by reference in this annual report, other than statements of historical fact, that address activities, events or developments that we or our management expect, believe or anticipate will or may occur in the future are forward-looking statements. These statements represent our reasonable judgment on the future based on various factors and using numerous assumptions and are subject to known and unknown risks, uncertainties and other factors that could cause our actual results and financial position to differ materially from those contemplated by the statements. You can identify these statements by the fact that they do not relate strictly to historical or current facts. They use words such as anticipate, estimate , project , forecast , plan, may , will , should , expect words of similar meaning. In particular, these include, but are not limited to, statements relating to the following:

- expectations and beliefs related to the combination with the LS Entities, including satisfying closing conditions and obtaining shareholder approval;
- anticipated benefits and expected synergies resulting from the combination with the LS Entities and beliefs associated with the integration of operations of both companies;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- expectations regarding capital expenditures, interest expense and other payments;
- beliefs and assumptions about economic conditions and the demand and prices for electricity;
- beliefs about commodity pricing and generation volumes;
- our focus on safety and our ability to efficiently operate our assets so as to maximize our revenue generating opportunities;
- strategies to capture opportunities presented by rising commodity prices and strategies to manage our exposure to energy price volatility;
- plans to achieve fuel-related, general and administrative, and other targeted cost savings;
- beliefs and assumptions relating to liquidity, including the ability to satisfy or refinance debt maturities and other obligations before or as they come due;

strategies to address our substantial leverage, to access the capital markets, or to obtain additional financing on more favorable financing terms;

measures to compete effectively with industry participants;

beliefs and assumptions about market competition, fuel supply, power demand, generation capacity and regional recovery of the wholesale power generation market;

sufficiency of coal and fuel oil inventories and transportation, including strategies to deploy coal supplies;

beliefs about the outcome of legal, regulatory, administrative and environmental matters;

expectations regarding environmental matters, including costs of compliance and availability and adequacy of emission credits;

expectations and estimates regarding the DMG consent decree and the associated costs;

positioning our power generation business for future growth and pursuing and executing acquisition, disposition or combination opportunities; and

measures to complete the exit from the customer risk management business and the costs associated with this exit.

Any or all of our forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors, many of which are beyond our control, including those set forth below.

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Factors That May Affect Future Results

Risks Related to Our Business

The Merger Agreement with the LS Entities and related transactions, regardless of whether they are ultimately consummated, have presented and will continue to present us with certain risks and uncertainties, and have imposed and will continue to impose on us and our business and operations certain restrictions and significant financial and other costs. In addition, if the Merger Agreement and related transactions are ultimately consummated, the expected benefits of the Merger Agreement and related transactions may not be realized in a timely or efficient manner or at all, and the LS Entities, by virtue of their stock ownership of New Dynegy, will have significant influence over New Dynegy s business and operations and may have interests that differ from, and conflict with, the interests of our other shareholders.

The consummation of the Merger Agreement with the LS Entities and related transactions is subject to the approval of our shareholders. We cannot assure you that we will receive the approval of our shareholders in a timely manner or at all and, as a result, we cannot assure you that the Merger Agreement and related transactions will be consummated in a timely manner or at all. Moreover, a substantial delay in obtaining the approval of our shareholders could have a material adverse effect on our and/or New Dynegy s business, financial condition and results of operations and may cause us and/or the LS Entities to abandon the Merger Agreement and related transactions. In addition, the Merger Agreement restricts us, without the LS Entities consent, from taking certain specified actions until the Merger Agreement is consummated or terminated. These restrictions may prevent us from pursuing otherwise attractive business opportunities and effecting other beneficial transactions and changes to our business and operations prior to the consummation or termination of the Merger Agreement.

We entered into the Merger Agreement with the LS Entities with the expectation that the combination of our business and operations with the business and operations of the power generation entities to be contributed by the LS Entities pursuant to the Merger Agreement would result in various benefits, including, among other things, certain synergies, cost savings and operating efficiencies. We cannot assure you that such benefits will be realized in a timely manner, in full or at all.

In addition, we have incurred and expect to continue to incur significant costs in connection with consummating the Merger Agreement and related transactions. We also expect to incur, upon the consummation of the Merger Agreement and related transactions, costs in connection with integrating our operations and procedures with the operations and procedures of the power generation entities to be contributed by the LS Entities. Moreover, we cannot assure you that the anticipated synergies, cost savings and operating efficiencies related to the integration of our business with that of the power generation entities to be contributed by the LS Entities will offset these costs over time, in a timely manner, in full or at all.

If the Merger Agreement and related transactions are consummated, we will face significant challenges in integrating our operations and procedures with the operations and procedures of the power generation entities to be contributed by the LS Entities. As a result, we cannot assure you that the integration will be completed in a timely or efficient manner. In addition, such integration efforts could also divert our management s focus and resources from our and, subsequent to the consummation of the Merger Agreement, New Dynegy s day-to-day business and operations. Such diversion of our management s focus and resources could have a material and adverse effect on our and, subsequent to the consummation of the Merger Agreement, New Dynegy s business, financial condition and results of operations.

Furthermore, subsequent to the consummation of the Merger Agreement and related transactions, the LS Entities will own approximately 40% of the voting power of New Dynegy and will have the right to nominate up to three members of the 11-member board of directors of New Dynegy. By virtue of such stock ownership and board representation, the LS Entities will have the power to influence New Dynegy s affairs as well as the outcome of matters submitted to a vote of New Dynegy s stockholders. Moreover, the LS Entities may have interests that differ from, and conflict with, those of our other shareholders, who will be holders of New Dynegy s common stock upon the consummation of the Merger Agreement and related transactions.

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Our growth strategy may include acquisitions or combinations that could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to realize anticipated benefits of those transactions.

Our growth strategy may include acquiring or combining with other businesses, such as the power generation facility acquisitions we propose to make pursuant to the Merger Agreement. We may not be able to identify suitable acquisition or combination opportunities or finance and complete any particular acquisition or combination successfully. Furthermore, acquisitions and combinations involve a number of risks and challenges, including:

- diversion of management s attention;
- the need to integrate acquired or combined operations;
- potential loss of key employees;
- difficulty in evaluating the power assets, operating costs, infrastructure requirements, environmental and other liabilities, and other factors beyond our control;
- potential lack of operating experience in new geographic/power markets;
- an increase in our expenses and working capital requirements; and
- the possibility that we may be required to issue a substantial amount of additional equity securities or incur additional debt to finance any such transactions.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize synergies or other anticipated benefits from a strategic transaction. Furthermore, the market for transactions is highly competitive, which may adversely affect our ability to find transactions that fit our strategic objectives. In pursuing our strategy, consistent with industry practice, we routinely engage in discussions with industry participants regarding potential transactions, large and small. We intend to continue to engage in strategic discussions and we will need to respond to potential opportunities quickly and decisively. As a result, strategic transactions may occur at anytime and may be significant in size relative to our assets and operations.

Because many of our power generation facilities operate mostly without term power sales agreements and because wholesale power prices are subject to significant volatility, our revenues and profitability are subject to significant fluctuations.

Most of our facilities operate as merchant facilities without term power sales agreements. Without term power sales agreements, we cannot be sure that we will be able to sell any or all of the electric energy, capacity or ancillary services from our facilities at commercially attractive rates or that our facilities will be able to operate profitably. This could lead to decreased financial results as well as future impairments of our property, plant and equipment or to the retirement of certain of our facilities resulting in economic losses and liabilities.

Because we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other power markets on a term basis, we are not guaranteed any rate of return on our capital investments. Rather, our financial condition, results of operations and cash flows are likely to depend, in large part, upon prevailing market prices for power and the fuel to generate such power. Wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable.

Given the volatility of power commodity prices, to the extent we do not secure term power sales agreements for the output of our power generation facilities, our revenues and profitability will be subject to increased volatility, and our financial condition, results of operations and cash flows could be materially adversely affected.

Our hedging activities will not fully protect us from exposure to commodity price risks, and we are vulnerable to decreases in power prices and increases in the price of natural gas, coal and oil. To the extent we do engage in hedging activities, our models representing the market may be inaccurate.

Since a substantial portion of our production capacity may not be hedged and is thus subject to commodity price risks, we have the potential to receive higher or lower prices for capacity, energy and ancillary services resulting in volatile revenue and cash flow. To the extent that our generated power is not subject to a power purchase agreement or similar arrangement, we generally will pursue sales of such generated power based on current market prices. Where forward sales are not executed, we will be impacted by changes in commodity prices, and, in an environment where fuel costs increase and power prices decrease, our financial condition, results of operations and cash flows may be materially adversely affected. In those instances where we do execute forward sales or related financial transactions, our internal models may not accurately represent the markets in which we participate, potentially causing us to make less favorable decisions.

Unauthorized hedging and related activities by our employees could result in significant losses.

We intend to continue our commercial strategy, which emphasizes forward power sales opportunities to capture attractive market prices in the near-term. We have adopted various internal policies and procedures designed to monitor hedging activities and positions. These policies and procedures are designed, in part, to prevent unauthorized purchases or sales of products by our employees. We cannot assure, however, that these steps will detect and prevent all violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. A significant policy violation that is not detected could result in a substantial financial loss for us.

We are exposed to the risk of fuel and fuel transportation cost increases and interruptions in fuel supplies because some of our facilities do not have long-term coal, natural gas or liquid fuel supply agreements.

Many of our power generation facilities, specifically those that are natural gas-fired, purchase their fuel requirements under short-term contracts or on the spot market. As a result, we face the risks of supply interruptions and fuel price volatility, as fuel deliveries may not exactly match that required for energy sales, due in part to our need to pre-purchase fuel inventories for reliability and dispatch requirements.

Moreover, operation of many of our coal-fired generation facilities is highly dependent on our ability to procure coal. Although we have long-term contracts in place for our coal and coal transportation needs, power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. If we are unable to procure fuel for physical delivery at prices we consider favorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Availability and cost of emission credits could materially impact our costs of operations.

We are required to maintain, either by allocation or purchase, sufficient emission credits to support our operations in the ordinary course of operating our power generation facilities. These credits are used to meet our obligations imposed by various applicable environmental laws. If our operational needs require more than our allocated allowances of emission credits, we may be forced to purchase such credits on the open market, which could be costly. If we are unable to maintain sufficient emission credits to match our operational needs, we may have to curtail our operations so as not to exceed our available emission credits, or install costly new emissions controls. As we use the emissions credits that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such credits are available for purchase, but only at significantly higher prices, the purchase of such credits could materially increase our costs of operations in the affected markets.

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Competition in wholesale power markets, together with an oversupply of power generation capacity in certain regional markets, may have a material adverse effect on our financial condition, results of operations and cash flows.

We have numerous competitors and additional competitors may enter the industry. Our power generation business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities and other energy service companies in the sale of energy, as well as in the procurement of fuel, transmission and transportation services. Moreover, aggregate demand for power may be met by generation capacity based on several competing technologies, as well as power generating facilities fueled by alternative or renewable energy sources, including hydroelectric power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Regulatory initiatives designed to enhance renewable generation could increase competition from these types of facilities. In addition, a buildup of new electric generation facilities in recent years has resulted in an abundance of power generation capacity in certain regional markets we serve.

We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Energy customers, wholesale energy suppliers and transporters often seek financial guarantees, credit support such as letters of credit, and other assurances that their energy contracts will be satisfied. Companies with which we compete may have greater resources in these areas. In addition, many of our current facilities are relatively old. Newer plants owned by competitors will often be more efficient than some of our plants, which may put some of our plants at a competitive disadvantage. Over time, some of our plants may become obsolete in their markets, or be unable to compete, because of the construction of new, more efficient plants.

Other factors may contribute to increased competition in wholesale power markets. New forms of capital and competitors have entered the industry in the last several years, including financial investors who perceive that asset values are at levels below their true replacement value. As a result, a number of generation facilities in the United States are now in the hands of lenders and investment companies. Furthermore, mergers and asset reallocations in the industry could create powerful new competitors. Under any scenario, we anticipate that we will face competition from numerous companies in the industry, some of which have superior capital structures.

Moreover, many companies in the regulated utility industry, with which the wholesale power industry is closely linked, are also restructuring or reviewing their strategies. Several of those companies have discontinued or are discontinuing their unregulated activities and seeking to divest their unregulated subsidiaries. Some of those companies have had, or are attempting to have, their regulated subsidiaries acquire assets out of their or other companies unregulated subsidiaries. This may lead to increased competition between the regulated utilities and the unregulated power producers within certain markets. The future of the wholesale power generation industry is unpredictable, but may include restructuring and consolidation within the industry, the sale, bankruptcy or liquidation of certain competitors, the re-regulation of certain markets or a long-term reduction in new investment into the industry. To the extent that competition increases, our financial condition, results of operations and cash flows may be materially adversely affected.

The regional concentration of our business in the Midwest may increase the effects of adverse trends in that market.

A substantial portion of our business is located in the Midwest region of the United States. Changes in economic conditions in this market, including changing demographics, or oversupply of or reduced demand for power, could have a material adverse effect on our financial condition, results of operations and cash flows. A substantial portion of our net income is derived from our Baldwin facility. Any disruption of production at that facility could have a material adverse effect on our financial condition, results of operations and cash flows.

Under the terms of the power purchase agreement with AmerenIP, which expired at the end of 2006, our Midwest coal plants were partially contracted to AmerenIP at a fixed price per megawatt hour. For the year

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ended December 31, 2006, approximately 23% of our consolidated revenues were derived from transactions with AmerenIP. Currently, our results in the Midwest are exposed to volatility in market prices which could cause us to realize losses in a weak power price environment.

We depend on transmission facilities operated by RTOs and ISOs, which could result in an inability to sell and deliver power to the market that may, in turn, adversely affect the profitability of our generation facilities.

Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) have emerged in most of the markets in which we operate and compete. The RTOs and ISOs provide transmission services, administer transparent and competitive power markets and maintain system reliability. Many of these RTOs and ISOs operate real-time and day-ahead markets in which we sell energy. We may be affected by changes in market rules, tariffs, market structures, administrative fee allocations and market bidding rules in these RTOs and ISOs. The ISOs or RTOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, price limitations, offer caps and other mechanisms to guard against the potential exercise of market power in these markets. These types of price limitations and other regulatory mechanisms may adversely affect the profitability of our generation facilities that sell energy and capacity into the wholesale power markets.

We do not own, control or set the rates for the transmission facilities we use to deliver energy, capacity and ancillary services to our customers. In addition, transmission capacity may not be available to us, the total costs of transmission may exceed our projections or cause us to forego transactions, and changes in the transmission grid could reduce our revenues.

We do not own or control the transmission facilities required to sell the wholesale power from our generation facilities. If the transmission service from these facilities is unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. Furthermore, the rates for transmission capacity from these facilities are set by others and the market and thus are subject to changes, some of which could be significant. Moreover, changes in the transmission infrastructure within or connecting individual markets could reduce prices in those markets by increasing the amount of generating capacity competing to serve the same markets. As a result, our business financial condition, cash flows and results of operations may be materially adversely affected.

An event of loss and certain other events relating to our Dynegy Northeast Generation facilities could trigger a substantial obligation that would be difficult for us to satisfy.

We acquired the DNE power generating facilities in January 2001 for $950 million. In May 2001, we entered into an asset-backed sale-leaseback transaction relating to these facilities to provide us with long-term acquisition financing. In this transaction, we sold four of the six generating units comprising these facilities for approximately $920 million to Danskammer OL LLC and Roseton OL LLC, and we concurrently agreed to lease them back from these entities. We have no option to purchase the leased facilities at Roseton or Danskammer at the end of their lease terms, which end in 2035 and 2031, respectively. If one or more of the leases were to be terminated prior to the end of its term because of an event of loss, because it becomes illegal for us to comply with the lease, or because a change in law makes the facility economically or technologically obsolete, we would be required to make a termination payment in an amount sufficient to redeem the pass-through trust certificates related to the unit or facility for which the lease is terminated. As of December 31, 2006, the termination payment would be approximately $1 billion for all of our DNE facilities. It could be difficult for us to raise sufficient funds to make this termination payment if a termination of this type were to occur with respect to the DNE facilities, resulting in a material adverse effect on our financial conditions, results of operations, liquidity or cash flows.

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Our business is subject to complex government regulation. Changes in these regulations or in their implementation may affect costs of operating our facilities or our ability to operate our facilities or increase competition, any of which may negatively impact our results of operations.

We are subject to extensive federal, state and local laws and regulations governing the generation and sale of energy commodities, as well as discharge of materials into the environment and otherwise relating to the environment and public health and safety in each of the jurisdictions in which we will have operations. Compliance with these laws and regulations requires expenses (including legal representation) and monitoring, capital and operating expenditures, including those related to pollution control equipment, emission credits, remediation obligations and permitting at various operating facilities. Furthermore, these regulations are subject to change at any time, and we cannot predict what changes may occur in the future or how such changes might affect any facet of our business.

The costs and burdens associated with complying with the increased number of regulations may have a material adverse effect on us, if we fail to comply with the laws and regulations governing our business or if we fail to maintain or obtain advantageous regulatory authorizations and exemptions. Moreover, increased competition resulting from potential legislative changes, regulatory changes or other factors may create greater risks to the stability of our power generation earnings and cash flows generally. We could suffer erosion in market position, revenues and profits as competitors gain access to the service territories of our power generation subsidiaries.

Our costs for compliance with existing environmental laws are significant, and costs for compliance with new environmental laws could adversely affect our financial condition, results of operations and cash flows.

Our business is subject to extensive and frequently changing environmental regulation by federal, state and local authorities. Such environmental regulation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Existing environmental laws and regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, litigation or regulatory or enforcement proceedings could be commenced and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions. Proposals currently under consideration could, if and when adopted or enacted, require us to make substantial capital and operating expenditures. If any of these events occur, our business, operations and financial condition could be materially adversely affected.

Moreover, many environmental laws require approvals or permits from governmental authorities for the operation of a power generation facility, before construction or modification of a project may commence or before wastes or other materials may be discharged into the environment. The process for obtaining necessary permits can be lengthy and complex and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures. We are required to comply with numerous environmental laws and regulations, and to obtain numerous governmental permits when we construct, modify and operate our facilities. In addition, certain of our facilities are also required to comply with the terms of consent decrees or other governmental orders.

With the continuing trend toward stricter standards, greater regulation and more extensive permitting requirements, our capital and operating environmental expenditures are likely to be substantial and may increase in the future. We may not be able to obtain or maintain all required environmental regulatory permits or other approvals that we need to operate our business. If there is a delay in obtaining any required environmental regulatory approvals or permits, or if we fail to obtain or comply with any required approval or permit, the operation of our facilities may be interrupted or become subject to additional costs and, as a result, our business, financial condition, results of operations and cash flows could be materially adversely affected.

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Different regional power markets in which we compete or may compete in the future have changing transmission regulatory structures, which could materially adversely affect our performance in these regions.

Our financial condition, results of operations and cash flows are likely to be affected by differences in market and transmission regulatory structures in various regional power markets. Problems or delays that may arise in the formation and operation of new or maturing RTOs and similar market structures, or changes in geographic scope, rules or market operations of existing RTOs, may affect our ability to sell, the prices we receive for, or the cost to transmit power produced by our generating facilities. Rules governing the various regional power markets may also change from time to time, which could affect our costs or revenues. We are unable to assess fully the impact that these uncertainties may have on our business, as it remains unclear which companies will be participating in the various regional power markets, or how RTOs will develop or what regions they will cover.

Our financial condition, results of operations and cash flows could be adversely impacted by strikes or work stoppages by our unionized employees.

A majority of the employees at our facilities are subject to collective bargaining agreements with various unions that expire in 2007 and 2008. If union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor is uncertain. Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on our financial condition, results of operations and cash flows.

In the past, we have reported material weaknesses in our internal control over financial reporting and may identify material weaknesses in the future that could adversely affect investor confidence and impair the value of our common stock.

In connection with our management s assessments of the effectiveness of our internal control over financial reporting as of December 31, 2004 and 2005 and September 30, 2006, our management concluded that, as of such dates, we did not maintain effective internal control over our financial reporting due to a material weakness in our processes, procedures and controls related to the preparation, analysis and recording of the income tax provision. These control deficiencies have resulted in the restatement of our 2005, 2004 and 2003 annual consolidated financial statements. In addition, our management concluded that, as of September 30, 2006, we did not maintain effective internal control over our financial reporting due to a material weakness in our processes, procedures and controls related to the calculation and analysis of our risk management asset and liability balances. This material weakness resulted in an adjustment to our condensed consolidated financial statements as of and for the three months ended March 31, 2006 prior to being reported in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006. As further described in Item 9A Controls and Procedures, we remediated both material weaknesses during 2006 and determined that our internal control over financial reporting was effective as of December 31, 2006. However, despite the remedial measures that we implemented and our continuing efforts to improve our internal control over our financial reporting, we may not be able to implement and maintain effective internal control over our financial reporting in the future. Moreover, we have experienced from time to time deficiencies in our internal control over our financial reporting that have not risen to the level of a material weakness. Although we have been able to remediate these deficiencies in the past, we cannot assure you that a material weakness will not exist in the future, as additional deficiencies in our internal control over our financial reporting may be discovered which may rise to the level of a material weakness.

Any failure to remedy additional deficiencies in our internal control over our financial reporting that may be discovered in the future or to implement new or improved controls, or difficulties encountered in the implementation of such controls, could cause us to fail to meet our reporting obligations or result in material misstatements in our financial statements. Any such failure could, in turn, affect the future ability of our management to certify that our internal control over our financial reporting is effective and, moreover, affect the

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results of our independent registered public accounting firm s attestation report regarding our management s assessment. Inferior internal control over our financial reporting could also subject us to the scrutiny of the SEC, the New York Stock Exchange (on which our Class A common stock is listed and traded) and other regulatory bodies and could cause investors to lose confidence in our reported financial information, which could have an adverse effect on the trading price of our common stock.

The ultimate outcome of unresolved legal proceedings and investigations relating to our past activities cannot be predicted. Any adverse determination could have a material adverse effect on our financial condition, results of operations and cash flows.

We are, or have in recent years been, a party to various material litigation matters and regulatory matters arising out of our business operations. These matters include, among other things, certain actions and investigations by the FERC and related regulatory bodies, litigation with respect to alleged actions in the western power and natural gas markets, purported class action suits with respect to alleged violations of the Employment Retirement Income Security Act of 1974 and various other matters. The ultimate outcome of pending matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome in each case reasonably be estimated.

Risks Related to Investing in Our Common Stock

If we issue a material amount of our common stock in the future or certain of our stockholders sell a material amount of our common stock, our ability to use our federal net operating losses to offset our future taxable income may be limited under Section 382 of the Internal Revenue Code.

Our ability to utilize previously incurred federal net operating losses (NOLs) to offset future taxable income would be limited if we were to undergo an ownership change within the meaning of Section 382 of the Internal Revenue Code (the Code). In general, an ownership change occurs whenever the percentage of the stock of a corporation owned by 5-percent shareholders (within the meaning of Section 382 of the Code) increases by more than 50 percentage points over the lowest percentage of the stock of such corporation owned by such 5-percent shareholders at anytime over the preceding three years. Under certain circumstances, sales or dispositions of our common stock by Chevron, or other stockholders could trigger an ownership change , and we will have limited control over the timing of any such sales or dispositions of our common stock. Any such future ownership change could result in limitations, pursuant to Section 382 of the Code, on our utilization of federal NOLs to offset our future taxable income.

More specifically, depending on prevailing interest rates and our market value at the time of such future ownership change, an ownership change under Section 382 of the Code would establish an annual limitation which might prevent full utilization of the deferred tax assets attributable to our previously incurred federal NOLs against the total future taxable income of a given year. The proposed Merger Agreement with the LS Entities will increase the likelihood that previously incurred federal NOLs will become subject to the limitations set forth in Section 382 of the Code. If such an ownership change were to occur, our and, subsequent to the consummation of the Merger Agreement and related transactions (if consummated), New Dynegy s ability to raise additional equity capital may be limited.

The magnitude of such limitations and their effect on us and, subsequent to the consummation of the Merger Agreement with the LS Entities and related transactions (if consummated), their effect on New Dynegy, is difficult to assess and depends in part on our or New Dynegy s (as the case may be) value at the time of any such ownership change and prevailing interest rates. For accounting purposes, at December 31, 2006, our net operating loss deferred tax asset attributable to our previously incurred federal NOLs was valued at approximately $332 million.

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The payment of dividends on our common stock is restricted and, moreover, subject to the discretion of our Board of Directors.

The financing agreements under which certain of our subsidiaries are borrowers and we are guarantors contain certain restrictions on the payment of dividends on our Class A common stock. Moreover, even if permitted under our financing agreements, dividend payments on our Class A common stock will be at the discretion of our Board of Directors. We have not paid a dividend on any class of our common stock since 2002.

We have significant debt that could negatively impact our business, and our credit ratings are less than investment grade.

We are highly leveraged, and have pledged substantially all of our assets to secure our debt. We have total debt of $3.3 billion at December 31, 2006. Our significant level of debt could:

- make it difficult to satisfy our financial obligations, including debt service requirements;
- limit our ability to obtain additional financing to operate our business;
- limit our financial flexibility in planning for and reacting to business and industry changes;
- impact the evaluation of our creditworthiness by counterparties to commercial agreements and affect the level of collateral we are required to post under such agreements;
- place us at a competitive disadvantage compared to less leveraged companies;
- increase our vulnerability to general adverse economic and industry conditions, including changes in interest rates and volatility in commodity prices; and
- require us to dedicate a substantial portion of our cash flows to payments on our debt, thereby reducing the availability of our cash flow for other purposes including our operations, capital expenditures and future business opportunities.

We may incur additional indebtedness as part of completing the Merger Agreement and related transactions in the future. If new debt is added to our current debt levels, the related risks that we face could increase significantly.

Our access to the capital markets may be limited.

We are a highly leveraged company with near-term capital needs; we may also require additional capital from time to time beyond the near-term. Unlike those companies in the power generation industry that are investment grade and for which the capital markets are typically open, our access to the capital markets may be limited. Moreover, the timing of any capital-raising transaction may be impacted by unforeseen events, such as strategic growth opportunities, legal judgments or regulatory requirements, which could require us to pursue additional capital in the near-term. Our ability to obtain capital and the costs of such capital are dependent on numerous factors, including:

- general economic and capital market conditions;
- covenants in our existing debt and credit agreements;
- credit availability from banks and other financial institutions;
- investor confidence in us and the regional wholesale power markets;
- our financial performance and the financial performance of our subsidiaries;
- our levels of indebtedness;
- our requirements for posting collateral under various commercial agreements;

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- our maintenance of acceptable credit ratings;
- our cash flow;
- provisions of tax and securities laws that may impact raising capital; and
- our long-term business prospects.

We may not be successful in obtaining additional capital for these or other reasons. An inability to access capital may limit our ability to pursue development projects, plant improvements or acquisitions that we may rely on for future growth and to comply with regulatory requirements and, as a result, may have a material adverse effect on our financial condition, results of operations and cash flows, and on our ability to execute our business strategy.

The interests of Chevron may conflict with your interests.

At December 31, 2006, Chevron owned approximately 19.4% of the voting power of Dynegy (assuming conversion of all of the Class B common stock beneficially owned by Chevron). By virtue of such stock ownership, Chevron has the power to influence our affairs and the outcome of matters required to be submitted to stockholders for approval.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

We have included descriptions of the location and general character of our principal physical operating properties by segment in Item 1. Business beginning on page 1. Those descriptions are incorporated herein by this reference. Substantially all of our assets, including the power generation facilities we own, are pledged as collateral to secure the repayment of, and our other obligations under, the Fourth Amended and Restated Credit Facility (first lien) and the 8.375% Senior Unsecured Notes due 2016 issued by DHI (second lien). Please read Note 12 Debt beginning on page F-36 for further discussion.

Our principal executive office located in Houston, Texas is held under a lease that expires in December 2017 as a result of an extension signed in 2006. We also lease additional offices or warehouses in the states of California, Colorado, Illinois, Indiana, New York and Texas.

Item 3. ***Legal Proceedings***

For a description of our material legal proceedings, please read Note 17 Commitments and Contingencies beginning on page F-47, which is incorporated herein by reference.

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

No matter was submitted to a vote of our security holders during the fourth quarter 2006.

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PART II

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

Our Class A common stock, no par value per share, is listed and traded on the New York Stock Exchange under the ticker symbol DYN . The number of stockholders of record of our Class A common stock as of February 22, 2007, based upon records of registered holders maintained by our transfer agent, was 19,389.

Our Class B common stock, no par value per share, is neither listed nor traded on any exchange. All of the shares of Class B common stock are owned by Chevron.

The following table sets forth the high and low closing sales prices for the Class A common stock for each full quarterly period during the fiscal years ended December 31, 2006 and 2005 and during the elapsed portion of our first fiscal quarter of 2007 prior to the filing of this Form 10-K, as reported on the New York Stock Exchange Composite Tape.

Summary of Dynegy s Common Stock Price

	High	Low
2007:		
First Quarter (through February 22, 2007)	$ 8.08	$ 6.52
2006:		
Fourth Quarter	$ 7.24	$ 5.36
Third Quarter	6.34	5.09
Second Quarter	5.47	4.68
First Quarter	5.72	4.72
2005:		
Fourth Quarter	$ 5.07	$ 4.15
Third Quarter	5.63	4.35
Second Quarter	5.10	3.23
First Quarter	4.75	3.62

During the fiscal years ended December 31, 2006 and 2005, our Board of Directors did not elect to pay a common stock dividend. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Dividends on Common Stock on page 52 for further discussion of our dividend policy and the impact of dividend restrictions contained in our financing agreements. Any decision to pay a dividend will be at the discretion of the Board of Directors, and subject to the terms of our then-outstanding indebtedness, but we do not expect to pay a common stock dividend in the foreseeable future. We have not paid a dividend on any class of our common stock since 2002. Please read Note 19 Capital Stock Common Stock beginning on page F-55 for further discussion.

Shareholder Agreement

A shareholder agreement that we entered into with Chevron in 2003, as amended on May 26, 2006, grants Chevron preemptive rights to acquire shares of our common stock in proportion to its then-existing interest in our equity value whenever we issue any equity securities, including securities issued pursuant to employee benefit plans. Chevron agreed to waive its preemptive rights with respect to the equity securities we issued in connection with the Series B Exchange and our August 2003 refinancing and up to $250 million in equity securities we may issue in one or more future underwritten offerings.

In addition, Chevron and its affiliates may acquire up to 40% of the total combined voting power of our outstanding voting securities without restriction in the shareholder agreement. Shares of Class B common stock issued to Chevron upon the mandatory conversion of Chevron s Class C convertible preferred stock are not counted when calculating this 40% threshold. We have agreed not to take any action that would cause Chevron s ownership to exceed this 40% threshold.

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If Chevron or its affiliates wish to acquire more than 40% of the total combined voting power of our outstanding voting securities, the shareholder agreement requires Chevron to make an offer to acquire all of our outstanding voting securities for cash or freely tradable securities listed on a national securities exchange. Any offer by Chevron or its affiliates for all of our outstanding voting securities would be subject to the auction procedures outlined in the agreement.

Chevron s ownership of our Class B common stock entitles it to designate up to three members of our Board of Directors. The shareholder agreement prohibits Chevron from selling or transferring shares of Class B common stock except in the following transactions:

- a widely-dispersed public offering;
- an unsolicited sale to a third party, provided that we or our designee are given the opportunity to purchase the shares proposed to be sold; or
- a solicited sale to an acceptable third party, provided that if we advise Chevron that the sale to a third party is not acceptable, we must purchase all of the offered shares for cash at a purchase price equal to 105% of the third party offer.

Upon the sale or transfer to any person other than an affiliate of Chevron, the shares of Class B common stock automatically convert into shares of Class A common stock.

The shareholder agreement further provides that we may require Chevron and its affiliates to sell all of the shares of Class B common stock under specified circumstances. These rights are triggered if Chevron or its Board designees block which they are entitled to do under our Bylaws any of the following transactions two times in any 24-month period or three times over any period of time:

- the issuance of new shares of stock where the aggregate consideration to be received exceeds the greater of $1 billion or one-quarter of our total market capitalization;
- any merger, consolidation, joint venture, liquidation, dissolution, bankruptcy, acquisition of stock or assets, or issuance of common or preferred stock, any of which would result in payment or receipt of consideration having a fair market value exceeding the greater of $1 billion or one-quarter of our total market capitalization; or
- any other material transaction or series of related transactions which would result in the payment or receipt of consideration having a fair market value exceeding the greater of $1 billion or one-quarter of our total market capitalization.

However, upon occurrence of one of these triggering events and in lieu of selling Class B common stock, Chevron may elect to retain the shares of Class B common stock but forfeit its right and the right of its Board designees to block the subject transaction. A block consists of a vote against a proposed transaction by either (a) all of Chevron s representatives on our Board of Directors present at the meeting where the vote is taken (if the transaction would otherwise be approved by our Board of Directors) or (b) any of the Class B common stock held by Chevron and its affiliates if the transaction otherwise would be approved by at least two-thirds of all other shares entitled to vote on the transaction, excluding shares held by our management, directors or subsidiaries.

The shareholder agreement also prohibits us from taking the following actions:

- issuing any shares of Class B common stock to any person other than Chevron and its affiliates;

- adopting a shareholder rights plan, poison pill or similar device that prevents Chevron from exercising its rights to acquire shares of common stock or from disposing of its shares when required by us; and

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acquiring, owning or operating a nuclear power facility, other than being a passive investor in a publicly-traded company that owns a nuclear facility.

Generally, the provisions of the shareholder agreement terminate on the date Chevron and its affiliates cease to own shares representing at least 15% of our outstanding voting power. At such time, all of the shares of Class B common stock held by Chevron would convert to shares of Class A common stock.

Chevron has agreed to vote its shares of Class B common stock in favor of the Merger Agreement and the merger with the LS Entities. As a result of the transaction, all of Chevron s Class B common stock will be converted into shares of Class A common stock of New Dynegy.

Registration Rights Agreement

We have entered into a registration rights agreement with Chevron that grants Chevron certain registration rights with respect to its shares of our Class B common stock in the event the proposed Merger Agreement with the LS Entities is not consummated. Under the agreement, we would be required to prepare and file with the SEC, and use our best efforts to cause to be declared effective, a shelf registration statement covering the resale of the shares of Class B common stock held by Chevron. If the Merger Agreement is not consummated, Chevron could also require us to effect up to two underwritten offerings during the period ending on December 31, 2007, and up to two additional underwritten offerings per calendar year thereafter. New Dynegy has also entered into a registration rights agreement with Chevron, under which New Dynegy will have similar obligations with respect to the resale of the shares of Class A common stock of New Dynegy which Chevron will own if the proposed Merger Agreement with the LS Entities is consummated.

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Shareholder Return Performance Presentation

The performance graph shown on the following page was prepared by Research Data Group, Inc., using data from the Research Data Group s database. As required by applicable rules of the SEC, the graph was prepared based upon the following assumptions:

1. $100 was invested in Dynegy Class A common stock, the S&P 500, the 2006 Peer Group (as defined below) and the 2005 Peer Group (as defined below) on December 31, 2001.

2. The returns of each component company in the 2006 Peer Group and the 2005 Peer Group are weighed based on the market capitalization of such company at the beginning of the measurement period.

3. Dividends are reinvested on the ex-dividend dates.

Our peer group for the fiscal year ended December 31, 2006, which we refer to as the 2006 Peer Group, is comprised of AES Corporation; Mirant Corporation; NRG Energy, Inc.; and Reliant Energy, Inc. Our peer group for the fiscal year ended December 31, 2005, which we refer to as the 2005 Peer Group, is comprised of AES Corporation; Calpine Corporation; Duke Energy Corporation; El Paso Corporation; NRG Energy, Inc.; and Reliant Energy, Inc.

For our 2006 Peer Group, we eliminated Calpine Corporation, Duke Energy Corporation and El Paso Corporation. We effected this change in an attempt to better reflect our current industry peers based on the comparability of each company s size, asset profile and business focus and strategy. While our 2006 business operations were focused primarily on power generation, our 2005 Peer Group included companies that competed with us in more than one line of business, namely power generation and/or natural gas liquids.

* $100 invested on 12/31/01 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

	12/01	12/02	12/03	12/04	12/05	12/06
Dynegy Inc.	100.00	4.68	16.98	18.33	19.20	28.72
S & P 500	100.00	77.90	100.24	111.15	116.61	135.03
2005 Peer Group	100.00	32.12	43.43	58.75	63.39	82.48
2006 Peer Group	100.00	18.79	50.86	80.21	87.54	117.72

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The stock price performance included in this graph is not necessarily indicative of future stock price performance.

The above stock price performance comparison and related discussion is not to be deemed incorporated by reference by any general statement incorporating by reference this Form 10-K into any filing under the Securities Act of 1933 or under the Securities Exchange Act of 1934, or otherwise, except to the extent that we specifically incorporate this stock price performance comparison and related discussion by reference, and is not otherwise deemed filed under the Acts.

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

The selected financial information presented below was derived from, and is qualified by reference to, our Consolidated Financial Statements, including the notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial Statements and related notes and Management s Discussion and Analysis of Financial Condition and Results of Operations.

Dynegy s Selected Financial Data

	Year Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$ 2,017	$ 2,313	$ 2,451	$ 2,599	$ 2,109
Depreciation and amortization expense	(230)	(220)	(235)	(373)	(378)
Goodwill impairment				(311)	(814)
Impairment and other charges	(155)	(46)	(78)	(225)	(176)
General and administrative expenses	(196)	(468)	(330)	(315)	(297)
Operating income (loss)	52	(838)	(100)	(769)	(1,146)
Interest expense and debt conversion expense	(631)	(389)	(453)	(503)	(241)
Income tax benefit	168	395	172	296	337
Net loss from continuing operations	(358)	(804)	(180)	(813)	(1,217)
Income (loss) from discontinued operations (3)	24	899	165	81	(1,136)
Cumulative effect of change in accounting principles	1	(5)		40	(234)
Net income (loss)	$ (333)	$ 90	$ (15)	$ (692)	$ (2,587)
Net income (loss) applicable to common stockholders (4)	(342)	68	(37)	321	(2,917)
Basic earnings (loss) per share from continuing operations	$ (0.80)	$ (2.13)	$ (0.53)	$ 0.53	$ (4.23)
Basic net income (loss) per share	(0.75)	0.18	(0.10)	0.86	(7.97)
Diluted earnings (loss) per share from continuing operations	$ (0.80)	$ (2.13)	$ (0.53)	$ 0.50	$ (4.23)
Diluted net income (loss) per share	(0.75)	0.18	(0.10)	0.78	(7.97)
Shares outstanding for basic EPS calculation	459	387	378	374	366
Shares outstanding for diluted EPS calculation	509	513	504	423	370
Cash dividends per common share	$	$	$	$	$ 0.15
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ (194)	$ (30)	$ 5	$ 876	$ (25)

Net cash provided by (used in) investing activities	358	1,824	262	(266)	677
Net cash used in financing activities	(1,342)	(873)	(115)	(900)	(44)
Cash dividends or distributions to partners, net	(17)	(22)	(22)		(55)
Capital expenditures, acquisitions and investments	(163)	(315)	(314)	(338)	(981)

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	December 31,				
	2006	2005	2004	2003	2002
	(in millions)				
Balance Sheet Data (2):					
Current assets	$ 2,082	$ 3,706	$ 2,728	$ 3,074	$ 7,574
Current liabilities	1,259	2,116	1,802	2,450	6,748
Property and equipment, net	4,951	5,323	6,130	8,178	8,458
Total assets	7,630	10,126	9,843	12,801	20,020
Long-term debt (excluding current portion)	3,190	4,228	4,332	5,893	5,454
Notes payable and current portion of long-term debt	68	71	34	331	861
Serial preferred securities of a subsidiary				11	11
Subordinated debentures					200
Series B Preferred Stock (5)					1,212
Series C convertible preferred stock		400	400	400	
Minority interest			106	121	146
Capital leases not already included in long-term debt	6				15
Total equity	2,267	2,140	1,956	1,975	2,256

(1) The Sithe Energies (February 1, 2005) and Northern Natural (February 1, 2002) acquisitions were accounted for in accordance with the purchase method of accounting and the results of operations attributable to the acquired businesses are included in our financial statements and operating statistics beginning on the acquisitions effective date for accounting purposes.

(2) The Sithe Energies and Northern Natural acquisitions were each accounted for under the purchase method of accounting. Accordingly, the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as of the effective dates of each transaction. See note (1) above for respective effective dates.

(3) Discontinued operations include the results of operations from the following businesses:

Northern Natural (sold third quarter 2002);

U.K. Storage Hornsea facility (sold fourth quarter 2002) and Rough facility (sold fourth quarter 2002);

DGC (portions sold in fourth quarter 2002 and first and second quarters 2003);

Global Liquids (sold fourth quarter 2002);

U.K. CRM (substantially liquidated in first quarter 2003); and

DMSLP (sold fourth quarter 2005).

(4) In August 2003, we consummated a restructuring of our Series B Preferred Stock in which we recognized an approximate $1 billion gain on the restructuring.

(5) The 2002 amount equals $1.5 billion in proceeds related to outstanding Series B Preferred Stock less a $660 million implied dividend recognized in connection with a beneficial conversion option plus $372 million in accretion of the implied dividend through December 31, 2002.

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

The following discussion should be read together with the audited consolidated financial statements and the notes thereto included in this report.

OVERVIEW

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as three separate segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also separately report the results of our CRM business, which primarily consists of the Kendall power tolling arrangement (excluding the Sithe toll which is now in our GEN-NE segment and is an intercompany agreement) as well as our legacy natural gas, power and emission trading positions. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. As described below, our NGL business, which was conducted through DMSLP and its subsidiaries, was sold to Targa on October 31, 2005. Additionally, as described below, our former REG business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation on September 30, 2004.

The following is a brief discussion of each of our power generation segments, including a list of key factors that have affected, and are expected to continue to affect, their respective earnings and cash flows. We also present a brief discussion of our CRM business, our corporate-level expenses and our discontinued businesses. This Overview section concludes with a discussion of our 2006 company highlights, our key objectives and our ongoing strategic outlook. Please note that this Overview section is merely a summary and should be read together with the remainder of this Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, as well as our audited consolidated financial statements, including the notes thereto, and the other information included in this report.

Business Discussion

Power Generation Business

We generate earnings and cash flows in the three segments within our power generation business through sales of electric energy, capacity and ancillary services. Primary factors affecting our earnings and cash flows in the power generation business are the prices for power, natural gas and coal, which in turn are largely driven by supply and demand. As further discussed below, demand for power can vary regionally due to weather and general economic conditions, among other things. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation. We are also impacted by the relationship between prices for power and natural gas and prices for power and fuel oil, commonly referred to as the spark spread , which impacts the margin we earn on the electricity we generate. We believe that our significant coal-fired generating facilities partially mitigate our sensitivity to changes in the spark spread, in that our delivered cost of coal, particularly in the Midwest region, is relatively stable and positions us for potential increases in earnings and cash flows in an environment where both power and natural gas prices increase.

Other factors that have affected, and are expected to continue to impact, earnings and cash flows for this business include:

- our ability to control capital expenditures, which primarily are limited to maintenance, safety, environmental and reliability projects, and to control other costs through disciplined management;

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- our ability to optimize our assets by maintaining a high in-market availability, reliable run-time and safe, efficient operations;
- the cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive; and
- the evaluation of our generation portfolio for rationalization of non-strategic assets.

Please read Item 1A. Risk Factors beginning on page 22 for additional factors that could affect our future operating results, financial condition and cash flows.

In addition to these overarching factors, other factors have influenced, and are expected to continue to influence, earnings and cash flows for our three reportable segments within the power generation business.

Power Generation Midwest Segment. Our assets in the Midwest include a coal-fired fleet and a natural gas-fired fleet. Although the primary factor affecting earnings and cash flows in GEN-MW, especially for the coal-fired fleet, is the market price of power, the following specific factors also affect or could affect the performance of this reportable segment:

- Our ability to maintain sufficient coal inventories, which is dependant upon the continued performance of the railroads for deliveries of coal in a consistent and timely manner, impacts our ability to serve the critical winter and summer on-peak loads;
- Any pursuit of the state of Illinois of legislation for a limitation of CO_2 emissions that is more stringent than federal guidelines could impose additional costs on our facilities;
- Political, legislative, judicial and/or regulatory actions over the next several months that could alter the Illinois auction results substantially;
- A significant amount of cash will be utilized for capital expenditures required to comply with the Midwest consent decree for the next few years; and
- Earnings and cash flows are primarily weather driven for our natural gas-fired fleet. A warm summer or cold winter increases demand for electricity, which in turn can increase run time of our peaking units and the demand for capacity and energy from these units.

Power Generation Northeast Segment. Our assets in the Northeast include natural gas, fuel oil and coal-fired facilities. The following specific factors also impact or could impact the performance of this reportable segment:

- Our ability to maintain sufficient coal and fuel oil inventories, including the continued deliveries of coal in a consistent and timely manner, impacts our ability to serve the critical winter and summer on-peak load;

State-driven programs aimed at capping mercury and carbon dioxide emissions that are more stringent than federal guidelines could impose additional costs on our facilities; and

The outcome of administrative proceedings and litigation specific to water intake issues could materially impact operating costs at two of our New York facilities.

Power Generation South Segment. Assets in our South segment are all natural gas-fired facilities. Our ERCOT facility is a baseload facility, and our other wholly-owned assets in the segment are peaking units. The following specific factors also impact or could impact the performance of this reportable segment:

For the peaking units, earnings and cash flows are primarily weather driven. A warm summer or cold winter increases the demand for electricity, which in turn can increase the run time of our peaking plants;

Our ability to enter into capacity agreements for our peaking units could impact future results;

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Wholesale market design changes in ERCOT could impact our ability to sell the remainder of the energy and ancillary products of the CoGen Lyondell facility into the bilateral ERCOT markets or the daily ERCOT market, and

Our agreement dated January 31, 2007, to sell our interest in the Calcasieu power generation facility to Entergy. Subject to regulatory approval the transaction is expected to close in early 2008.

Customer Risk Management

Our CRM segment is comprised largely of the Kendall power tolling arrangement (excluding the Sithe toll which is now in our GEN-NE segment and is an intercompany agreement). We have agreed to acquire the Kendall facility from the LS Entities, and upon the closing of that acquisition the Kendall tolling arrangement will become an intercompany obligation under our GEN-MW segment. As a result, the accounting impact of the toll would be eliminated in our consolidated results. In addition, our CRM segment includes remaining natural gas, power and emission trading positions. We are actively pursuing opportunities to terminate, assign or renegotiate the terms of our remaining obligations under these agreements when circumstances are economically advantageous to us.

Regarding our legacy natural gas, power and emission trading positions, we have substantially reduced the size of our mark-to-market portfolio since October 2002, when we initiated our efforts to exit the CRM business. Our remaining natural gas transactions still require us to purchase natural gas for our customers; however, those cash requirements are partially offset by the proceeds received from financial contracts hedging a significant portion of the supply. Therefore, the profit and loss impacts of price movements are mitigated by these offsetting financial positions. All that remains of our power trading business, exclusive of our power tolling arrangement, is a minimal number of positions that will remain until 2010. Finally, we have a forward obligation to deliver SO_2 emissions allowances through 2008. Our financial statements reflect the gain or loss on this obligation resulting from the price fluctuation in SO_2 emissions allowances. This obligation will be satisfied by our current inventory of physical SO_2 emissions allowances, and such inventory is valued at the lower of cost or market, in accordance with GAAP. Upon settlement of the forward obligation, we will recognize a gain to the extent that the delivery price is higher than the book value of our inventory. Upon delivery of the emissions allowances, we expect a positive cash flow as the third party makes payment for the emissions allowances. The inventory of emissions allowances that we use to fulfill our forward obligation is separate from the inventory and needs of our power generation business.

Other

Other and Eliminations also includes corporate-level expenses such as general and administrative and interest. Significant items impacting future earnings and cash flows include:

interest expense, which reflects debt with a weighted-average rate of approximately 8%, and will continue to reflect our non-investment grade credit ratings;

general and administrative costs (G&A), with respect to which we have implemented a number of initiatives that have yielded savings, and which will be impacted by, among other things, (i) any future corporate-level litigation reserves or settlements; (ii) potential funding requirements under our pension plans; and (iii) increased G&A associated with additional resources required for the management and administration of assets acquired through the planned merger with the LS Entities; and income taxes, which will be impacted by our ability to realize our significant deferred tax assets, including loss carryforwards.

Discontinued Businesses

Natural Gas Liquids. Our natural gas liquids business, which we sold to Targa in October 2005, was comprised of our natural gas gathering and processing assets and integrated downstream assets used to

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fractionate, store, terminal, transport, distribute and market natural gas liquids. NGL s results are reflected in Discontinued Operations in our consolidated statements of operations.

Regulated Energy Delivery. Our regulated energy delivery business was comprised of our Illinois Power subsidiary prior to its sale to Ameren in September 2004. REG s results are reflected in Continuing operations in our consolidated statements of operations due to our significant continuing involvement with Ameren through power sales agreements.

Important Events

Pending LS Power Combination. On September 14, 2006, we entered into the Merger Agreement with the LS Entities, part of the LS Power Group, a privately held power plant investor, developer and manager, to combine a portion of the LS Entities operating generation portfolio with our generation assets, and for us to acquire a 50 percent ownership interest in a development company that is currently controlled by the LS Entities. The combined company (New Dynegy) will have nearly 20,000 MW of generating capacity. Upon completion of the Merger Agreement, which is subject to the affirmative vote of the holders of at least two-thirds of our Class A common stock and the satisfaction of other conditions, the combined company will own 29 operating power plants in 13 states (excludes the 351 MW Calcasieu generating facility, which we have agreed to sell to Entergy) employing a balanced mix of fuel sources with baseload, intermediate, and peaking dispatch capabilities, enhanced cash flow-generating opportunities, and significant scale and scope in three key geographic regions. The expanded portfolio will also include a controlling interest in the Plum Point facility, a 665 MW coal-fired plant currently under construction in Arkansas. Additionally, the development joint venture (referred to herein as the development company) will provide us with a 50 percent ownership interest in an established growth vehicle. The LS Entities current development activities include nine projects totaling more than 7,600 MW in various stages of development and approximately 2,300 MW of repowering and/or expansion opportunities.

Under the terms of the Merger Agreement, at closing the LS Entities will receive 340 million shares of New Dynegy s Class B common stock, $100 million in cash and $275 million aggregate principal amount of notes to be issued by New Dynegy. New Dynegy will also assume approximately $1.9 billion in net debt (debt less restricted cash and investments) from the LS Entities. Please read Note 3 Business Combinations and Acquisitions LS Power on page F-17 for further discussion of the terms of the Merger Agreement as well as the proxy statement/prospectus of Dynegy Acquisition, Inc. filed with the SEC on February 13, 2007.

Illinois Resource Procurement Auction. As a result of the Illinois resource procurement auction, in September 2006, DPM entered into two SFCs with subsidiaries of Ameren Corporation (the Ameren Illinois Utilities) to provide the Ameren Illinois Utilities with capacity, energy and related services.

Both of the SFCs are for services required by the Ameren Illinois Utilities to serve their residential and commercial electric customers starting January 1, 2007. The products to be provided by DPM under both SFCs include electric energy and certain ancillary and other services necessary to serve a full-requirements load. The first SFC extends through May 31, 2008 and is for 24 tranches of up to 50 MW per tranche. This amount translates to approximately 22.43% of the total Ameren Illinois Utilities relevant customers load during each hour of the contract period. The pricing for the first SFC is $64.77 per MW. The second SFC extends through May 31, 2009 and is for four tranches of up to 50 MW per tranche. This amount translates to approximately 3.74% of the total Ameren Illinois Utilities relevant customers load during each hour of the contract period. The pricing for the second SFC is $64.75 per MW. There is a possibility of political, legislative, judicial and/or regulatory actions over the next several months that could substantially affect the ability of the Ameren Illinois Utilities to honor their contractual commitments under the SFCs. We cannot predict the outcome of the ongoing actions, but an adverse result could negatively impact our financial position, results of operations and cash flows.

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Liability Management. We initiated several transactions to reduce debt and other obligations as well as enhance our capital structure during 2006 and accomplished the following:

March 2006 we entered into a third amended and restated credit agreement.

April 2006 we completed a tender offer and consent solicitation in which we purchased $151 million of our $225 million outstanding Second Priority Senior Secured Floating Rate Notes due 2008 (the 2008 Notes), substantially all of our $625 million 9.875% Second Priority Senior Secured Notes due 2010 and all $900 million of our 10.125% Second Priority Senior Secured Notes due 2013.

April 2006 we issued $750 million aggregate principal amount of our 8.375% Senior Unsecured Notes due 2016 in a private offering.

April 2006 we entered into a fourth amended and restated credit agreement.

May 2006 we completed an offer to convert all $225 million of our outstanding 4.75% Convertible Subordinated Debentures due 2023 into shares of our Class A common stock and cash.

May 2006 we completed a public offering of 40.25 million shares of our Class A common stock, including 5.25 million shares purchased pursuant to an underwriters over-allotment option, for proceeds of $23 million.

May 2006 we redeemed from Chevron all 8 million shares of our outstanding Series C convertible preferred stock for a cash purchase price of $400 million.

May 2006 we entered into a $150 million Term Loan structured as a new tranche under the Fourth Amended and Restated Credit Facility.

July 2006 we redeemed all $74 million of our remaining 2008 Notes.

July 2006 we issued $297 million additional principal amount of our 8.375% Senior Unsecured Notes due 2016 in exchange for all $419 million of outstanding Independence subordinated debt.

November 2006 we repaid the $150 million Term Loan with proceeds from the sale of the Rockingham facility.

Please read Note 12 Debt beginning on page F-36 for further discussion.

Other. In addition to these events, we also accomplished the following:

March 2006 we completed the termination of the Sterlington long-term wholesale power-tolling contract with Ouachita Power LLC with a cash payment of approximately $370 million.

March 2006 we completed our acquisition of NRG s 50% ownership interest in the entity that owns the Rocky Road power plant, a 330-megawatt natural gas-fired peaking facility near Chicago (of which Dynegy already owned 50%). In addition, we completed the sale to NRG of our 50% ownership interest in a joint venture between us and NRG that has ownership in power plants in southern California. As a result of these two transactions, we received net cash proceeds of approximately $165 million from NRG.

November 2006 we completed the sale of our Rockingham peaking facility to Duke Power for $194 million.

Key Objectives

First and foremost, we are focused on closing the Merger Agreement and related transactions with the LS Entities and integrating the two portfolios. If the transaction is consummated, we intend to use the combined company s power generation facility base and development portfolio as a platform for future growth and to take

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advantage of market opportunities, including commodity price volatility and expected regional market recoveries, to enhance our financial performance. We believe the combined company will be positioned to participate in further industry consolidation opportunities and to capitalize on expected regional power market recoveries designed to improve the predictability and quality of our cash flows.

Our commercial objectives are focused on three elements:

- Employing a business model and capital structure appropriate for a commodity cyclical business;
- Maintaining a diverse portfolio of assets consisting of both low-cost plants and those that can provide reliability and other services to the markets both during peak-demand periods and as overall regional electric demand increases over time; and
- Ensuring that all of our power generation facilities are ready to produce electricity when market demand and, therefore, market price, is highest.

More specifically, our business strategy includes the following:

Employ a Commodity Cyclical Business Model. We intend to optimize our assets by selling electricity and capacity into the spot and term markets when pricing is most attractive. This objective is best achieved through a diverse portfolio of assets commercialized through a combination of spot market sales and term contracts. While we do not have a prescribed allocation of volumes between spot and term market sales, we generally intend to rely on our low-cost coal facilities and term contractual sales arrangements to provide a base level of cash flow, while preserving financial exposure to market prices. We believe this strategy will allow us to benefit from both short-term and long-term market price increases. Consequently, our financial results will be sensitive to, and generally correlated with, commodity prices (especially natural gas prices, regional power prices and the spread between them).

We intend to maintain certain longer-term sales arrangements while retaining an ability to participate in near-term markets through both physical transactions and financial hedges, thereby creating a more stable portfolio that, while dependent on cyclical commodity markets, is also positioned to capture higher energy margins and improved capacity pricing.

Establish an Appropriate Capital Structure. We believe that the power industry is a commodity cyclical business with significant commodity price volatility and a considerable capital investment requirement. Thus, maximizing economic returns in this market environment requires a capital structure that can withstand power price volatility as well as a commercial strategy that captures the value associated with both short-term and long-term price trends. We intend to maintain a capital structure that is suitable for our commercial strategy and the commodity cyclical market in which we operate. Maintaining appropriate debt levels, maturities, and overall liquidity are key elements of this capital structure.

Consistent with these objectives, we are exploring a number of options to ensure an appropriate capital structure. Considerations include modifying the existing DHI bank debt arrangements, including increasing DHI s revolving credit facility, and increasing the capacity of existing letter of credit facilities to support future liquidity and collateral needs. As a result of our review and discussions with potential lenders, we may elect to pursue alternative capital structures, including holding our Sithe and LS entity assets under DHI, to be implemented in connection with the Merger Agreement with the LS Entities.

Such alternative capital structures, if they are implemented, could affect our earnings and cash flows in 2007 and beyond.

Focus on Operational Excellence. We focus on improving our historically strong operating track record to achieve increased plant availability, higher dispatch and capacity factors, and improved cost controls. By

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managing fuel costs, minimizing plant outages and reducing corporate overhead, we aim to improve our ability to effectively capture revenue opportunities in the market place. Moreover, we commit to operating our facilities in a safe, reliable and environmentally compliant manner.

Tightly Manage Costs and Expenditures. We manage costs and capital expenditures effectively. Likewise, our power generation facilities are managed to require a relatively predictable level of maintenance capital expenditures without compromising operational integrity. We believe these ongoing efforts should allow us to maintain focus on being a reliable, low-cost producer of power.

Position for Regional Market Recovery. We operate a balanced portfolio of generation assets that is diversified in terms of geography, fuel type and dispatch profile. As a result, we believe our substantial coal-fired, baseload fleet should continue to benefit from the impact of higher natural gas prices on power prices in the Midwest and Northeast, allowing it to capture greater margins. It is anticipated that, following the consummation of the Merger Agreement with the LS Entities, the combined cycle units should provide meaningful cash flows and should benefit from improved margins as demand increases in the Western and Northeast markets.

Please read Item 1A. Risk Factors beginning on page 22 for additional factors that could impact our future operating results, financial condition and cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, collateral requirements, fixed capacity payments and contractual obligations, capital expenditures and working capital needs. Examples of working capital needs include prepayments or cash collateral associated with purchases of commodities, particularly natural gas, coal and fuel oil, facility maintenance costs and other costs such as payroll. Our liquidity and capital resources are primarily derived from cash flows from operations, cash on hand, borrowings under our financing agreements, proceeds from asset sales and proceeds from capital market transactions.

Debt Obligations

During 2006, we continued our efforts to enhance our capital structure flexibility, reduce our outstanding debt and extend our maturity profile. Repayments of long-term debt totaled $1,930 million for the year ended December 31, 2006 and consisted of the following payments:

- $900 million in aggregate principal amount on our 10.125% Second Priority Senior Secured Notes due 2013;
- $614 million in aggregate principal amount on our 9.875% Second Priority Senior Secured Notes due 2010;

$225 million in aggregate principal amount on our 2008 Notes;

$150 million in aggregate principal amount on our Term Loan due 2012;

$23 million in aggregate principal amount on our 7.45% Senior Notes due 2006; and

$18 million in aggregate principal amount on our 8.50% secured bonds due 2007.

In addition to the above repayments, we redeemed all of the outstanding shares of our Series C Preferred for $400 million and we completed an offer to convert all $225 million of our outstanding 4.75% Convertible Subordinated Debentures due 2023 into shares of our Class A common stock and cash. Further, we issued $297

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million principal amount of additional 8.375% Senior Unsecured Notes due 2016 in exchange for all $419 million of outstanding Independence subordinated debt.

These repayments were partially offset by $1,071 million of proceeds from the following sources, net of approximately $29 million of debt issuance costs:

$750 million aggregate principal amount from a private offering of our 8.375% Senior Unsecured Notes due 2016;

$200 million letter of credit facility due 2012; and

$150 million term loan due 2012.

Following these transactions, our debt maturity profile as of December 31, 2006 includes $68 million in 2007, $44 million in 2008, $57 million in 2009, $73 million in 2010, $561 million in 2011 and approximately $2,455 million thereafter. Maturities for 2007 represent principal payments on the Independence Senior Notes and our 7.45% DHI Senior Notes included in Notes payable and current portion of long-term debt on our consolidated balance sheets. Scheduled maturities of debt expected to be acquired in the Merger Agreement with the LS Entities are: $14 million in 2007, $14 million in 2008, $164 million in 2009, $16 million in 2010, $18 million in 2011 and approximately $2,077 million thereafter. Please read Note 3 Business Combinations and Acquisitions LS Power beginning on page F-17 for further discussion.

Summarized Debt and Other Obligations. The following table depicts our consolidated third party debt obligations, including the principal-like maturities associated with the DNE leveraged lease, and the extent to which they are secured as of December 31, 2006 and 2005:

	December 31, 2006	December 31, 2005
	(in millions)	
First Secured Obligations		
Dynegy Holdings Inc.	$ 200	$
Sithe Energies (1)	448	885
Total First Secured Obligations	648	885
Second Secured Obligations	11	1,750
Unsecured Obligations	3,375	2,571
Subtotal	4,034	5,206
Preferred Obligations		400
Total Obligations	$ 4,034	$ 5,606
Less: DNE Lease Financing (2)	(801)	(785)

Less: Preferred Obligations		(400)
Other (3)	25	(122)
Total Notes Payable and Long-term Debt (4)	$ 3,258	$ 4,299

(1) Please read Note 3 Business Combinations and Acquisitions Sithe Energies beginning on page F-18 for further discussion.
(2) Represents present value of future lease payments discounted at 10%.
(3) Consists of net premiums on debt of $25 million and net discounts on debt of $122 million at December 31, 2006 and 2005, respectively.
(4) Does not include letters of credit.

Collateral Postings

We continue to use a significant portion of our capital resources, in the form of cash and letters of credit, to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. We manage the level of our collateral postings by line of business, rather than by reportable segment. This is primarily because collateral postings are generally determined on a counterparty basis, and our counterparties conduct business across reportable segments. The following table summarizes our consolidated collateral postings to third parties by line of business at February 22, 2007, December 31, 2006 and December 31, 2005:

	February 22, 2007	December 31, 2006	December 31, 2005
		(in millions)	
By Business:			
Generation business	$ 178	$ 134	$ 280
Customer risk management business	50	54	91
Other	7	7	10
Total	$ 235	$ 195	$ 381
By Type:			
Cash (1)	$ 40	$ 38	$ 122
Letters of credit	195	157	259
Total	$ 235	$ 195	$ 381

(1) Cash collateral consists of either cash deposits to cover physical deliveries or liabilities on mark-to-market positions or prepayments for commodities or services that are in advance of normal payment terms.

The increase in collateral postings from December 31, 2006 to February 22, 2007 is primarily due to increased fuel purchases and collateral postings just ahead of monthly commodity settlements.

The decrease in collateral postings from December 31, 2005 to December 31, 2006 is primarily due to a return of collateral postings of approximately $146 million in our generation business and $37 million in our customer risk management business. This decrease is primarily a result of decreases in commodity prices since the end of 2005 as well as the expiration of certain hedging positions. In addition, the $44 million of collateral posted on behalf of West Coast Power was returned as a result of the sale of our 50% interest in West Coast Power to NRG, completed on March 31, 2006.

Going forward, we expect counterparties collateral demands to continue to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their views of our creditworthiness. In addition, the contemplated merger with the LS Entities and the effect of the Illinois resource procurement auction will have a significant impact on our exposure to collateral demands. We believe that we have sufficient capital resources to satisfy counterparties collateral demands, including those for which no collateral is currently posted, for the foreseeable future. Over the longer term, we expect to achieve incremental collateral reductions associated with the completion of our exit from the customer risk management business.

Disclosure of Contractual Obligations and Contingent Financial Commitments

We incur contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contracts, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related operating activities. Financial commitments represent contingent obligations, such as financial guarantees, that become payable only if specified events occur. Details on these obligations are set forth below.

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Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2006. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Payments Due by Period						
	Total	2007	2008	2009	2010	2011	Thereafter
Long-term debt (including current portion)	$ 3,258	$ 68	$ 44	$ 57	$ 73	$ 561	$ 2,455
Interest payments on debt	2,019	283	260	253	248	205	770
Operating leases	1,476	139	164	164	117	133	759
Capital leases	16	2	2	2	2	2	6
Capacity payments	688	77	76	77	78	80	300
Conditional purchase obligations	114	12	11	11	12	13	55
Pension funding obligations	63	25	29	9			
Other obligations	28	5	5	5	5		8
Total contractual obligations	$ 7,662	$ 611	$ 591	$ 578	$ 535	$ 994	$ 4,353

The table above does not include amounts of long-term debt or other contractual obligations that are expected to be assumed as a result of the proposed Merger Agreement with the LS Entities. Please read Note 3 Business Combinations and Acquisitions LS Power beginning on page F-17 for further discussion.

Long-Term Debt (Including Current Portion). Total amounts of Long-term debt (including current portion) are included in the December 31, 2006 consolidated balance sheet. For additional explanation, please read Note 12 Debt beginning on page F-36.

Operating Leases. Operating leases includes the minimum lease payment obligations associated with our DNE leveraged lease. For additional information, please read Liquidity and Capital Resources Off-Balance Sheet Arrangements DNE Leveraged Lease beginning on page 50. Amounts also include minimum lease payment obligations associated with office and office equipment leases.

In addition, we are party to two charter party agreements relating to VLGCs previously utilized in our global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $14 million each year for the years 2007 through 2009, and approximately $51 million through lease expiration. The charter party rates payable under the two charter party agreements vary in accordance with market-based rates for similar shipping services. The $14 million and $51 million amounts set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary terms of the charter party agreements expire August 2013 and August 2014, respectively. On January 1, 2003, in connection with the sale of our global liquids business, we sub-chartered both VLGCs to a wholly-owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. We continue to rely on the sub-charters with a subsidiary of Transammonia to satisfy the obligations of our two charter party agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements.

Capital Leases. In January 2006, we entered into an obligation under a capital lease related to a coal loading facility which will be used in the transportation of coal to our Vermilion generating facility. Pursuant to our agreement with the lessor, we are obligated for minimum payments in the aggregate amount of $16 million over the remaining term of the lease.

Capacity Payments. Capacity payments include future payments aggregating $416 million under the Kendall power tolling arrangement, as further described in Item 1. Business Segment Discussion Customer Risk Management beginning on page 12.

In November 2004, we entered into a back-to-back power purchase agreement under which a subsidiary of Constellation receives our rights to capacity and energy under the Kendall power tolling arrangement for a four-year term expiring in November 2008. Although we are still obligated under the Kendall toll, as of December 31, 2006, we will receive approximately $81 million in aggregate cash payments from Constellation to offset our fixed payment obligations under the Kendall toll through November 2008, which payment obligations are reflected in the table above. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Kendall on page F-23 for further discussion.

In addition, capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $272 million.

Conditional Purchase Obligations. Amounts relate to our co-sourcing agreement with Accenture LLP for employee and infrastructure outsourcing. In early 2006, we amended the agreement to reduce our annual rate and to extend the term through 2016. We are obligated for minimum payments of approximately $114 million over the term of the agreement. This amended agreement may be cancelled at any time upon the payment of a termination fee not to exceed $1.7 million. This termination fee is in addition to amounts due for services provided through the termination date.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations for 2007 ($25 million), 2008 ($29 million) and 2009 ($9 million). Although we expect to continue to incur funding obligations subsequent to 2009, such amounts have not been included in this table because our estimates are imprecise.

Other Obligations. Other obligations include amounts related to a long-term coal agreement to assist in the delivery of coal to our Danskammer plant in Newburgh, New York. The agreement extends until 2010, and the minimum aggregate payments through expiration total approximately $10 million as of December 31, 2006. In addition, included in other obligations are payments associated with a capacity contract between Independence and Con Edison. The aggregate payments through the 2014 expiration are approximately $18 million as of December 31, 2006. Please read Note 3 Business Combinations and Acquisitions Sithe Energies beginning on page F-18 for more information on this agreement.

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2006 on an undiscounted basis. These obligations represent contingent obligations that may require a payment of cash upon the occurrence of specified events.

	Expiration by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
			(in millions)		
Letters of Credit (1)	$ 157	$ 121	$ 36	$	$
Surety Bonds (2)(3)	21	21			
Guarantees (4)	4		4		
Kendall guarantee (4)	200	200			

Total Financial Commitments	$ 382	$ 342	$ 40	$	$

(1) Amounts include outstanding letters of credit.

(2) Surety bonds are generally on a rolling 12-month basis. The $21 million of surety bonds were supported by collateral.

(3) As part of the power purchase agreement with Constellation, under which Constellation effectively receives our rights to purchase approximately 570 MW of capacity and energy arising from our tolling contract with

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Kendall, we have guaranteed Constellation the receipt of $3.5 million in reactive power revenues over the four-year period of the power purchase agreement which ends November 2008. Our receipt of these reactive power revenues to offset this obligation is predicated on, among other things, filing a reactive power tariff with the FERC.

(4) On September 14, 2006, certain of the LS Entities and Kendall Power LLC (Kendall Power), a newly formed wholly-owned subsidiary of Dynegy, entered into a Limited Liability Company Membership Interests and Stock Purchase Agreement (the Kendall Agreement) pursuant to which Kendall Power agreed to acquire all of the outstanding interests in LSP Kendall Holdings, LLC for $200 million in cash, as adjusted for certain changes in working capital. The closing of the Kendall Agreement will occur only if the closing of the Merger Agreement does not occur. We have agreed to guarantee certain of Kendall Power s obligations under the Kendall Agreement. Please read Note 17 Commitments and Contingencies Guarantees and Indemnifications Kendall Guarantee on page F-51 for further discussion.

The table above does not include contingent financial obligations that are expected to be assumed as a result of the proposed Merger Agreement with the LS Entities.

Off-Balance Sheet Arrangements

DNE Leveraged Lease. In May 2001, we entered into an asset-backed sale-leaseback transaction to provide us with long-term financing for our acquisition of certain power generating facilities. In this transaction, which was structured as a sale-leaseback to minimize our operating cost of the facilities on an after-tax basis and to transfer ownership to the purchaser, we sold for approximately $920 million four of the six generating units comprising the facilities to Danskammer OL LLC and Roseton OL LLC, each of which was newly formed by an unrelated third party investor, and we concurrently agreed to lease them back from these entities, which we refer to as the owner lessors. The owner lessors used $138 million in equity funding from the unrelated third party investor to fund a portion of the purchase of the respective facilities. The remaining $800 million of the purchase price and the related transaction expenses was derived from proceeds obtained in a private offering of pass-through trust certificates issued by two of our subsidiaries, Dynegy Danskammer, L.L.C. and Dynegy Roseton, L.L.C., which serve as lessees of the applicable facilities. The pass-through trust certificate structure was employed, as it has been in similar financings historically executed in the airline and energy industries, to optimize the cost of financing the assets and to facilitate a capital markets offering of sufficient size to enable the purchase of the lessor notes from the owner lessors. The pass-through trust certificates were sold to qualified institutional buyers in a private offering and the proceeds were used to purchase debt instruments, referred to as lessor notes, from the owner lessors. The lease payments on the facilities support the principal and interest payments on the pass-through trust certificates, which are ultimately secured by a mortgage on the underlying facilities.

As of December 31, 2006, future lease payments are $108 million for 2007, $144 million for 2008, $141 million for 2009, $95 million for 2010, $112 million for 2011 and $179 million for 2012, with $533 million in the aggregate due from 2013 through lease expiration. The Roseton lease expires on February 8, 2035 and the Danskammer lease expires on May 8, 2031. We have no option to purchase the leased facilities at the end of their respective lease terms. DHI has guaranteed the lessees payment and performance obligations under their respective leases on a senior unsecured basis. At December 31, 2006, the present value (discounted at 10%) of future lease payments was $801 million.

The following table sets forth our lease expenses and lease payments relating to these facilities for the periods presented.

	2006	2005	2004
		(in millions)	
Lease Expense	$ 50	$ 50	$ 50

Lease Payments (Cash Flows)	$ 60	$ 60	$ 60

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If one or more of the leases were to be terminated because of an event of loss, because it had become illegal for the applicable lessee to comply with the lease or because a change in law had made the facility economically or technologically obsolete, DHI would be required to make a termination payment in an amount sufficient to redeem the pass-through trust certificates related to the unit or facility for which the lease was terminated at par plus accrued and unpaid interest. As of December 31, 2006, the termination payment at par would be approximately $1 billion for all of the DNE facilities, which exceeds the $920 million we received on the sale of the facilities. If a termination of this type were to occur with respect to all of the DNE facilities, it would be difficult for DHI to raise sufficient funds to make this termination payment. Alternatively, if one or more of the leases were to be terminated because we determine, for reasons other than as a result of a change in law, that it has become economically or technologically obsolete or that it is no longer useful to our business, DHI must redeem the related pass-through trust certificates at par plus a make-whole premium in an amount equal to the discounted present value of the principal and interest payments still owing on the certificates being redeemed less the unpaid principal amount of such certificates at the time of redemption. For this purpose, the discounted present value would be calculated using a discount rate equal to the yield-to-maturity on the most comparable U.S. Treasury security plus 50 basis points.

For further discussion of the accounting and required disclosure surrounding the subsidiaries that issued the pass-through certificates and purchased the notes from the owner lessors, please read Note 10 Unconsolidated Investments Variable Interest Entities beginning on page F-34.

Capital Expenditures

We continue to tightly manage our operating costs and capital expenditures. We had approximately $155 million in capital expenditures during 2006. Our 2006 capital spending by reportable segment was as follows (in millions):

GEN-MW	$ 101
GEN-NE	22
GEN-SO	24
Other	8
Total	$ 155

Capital spending in our GEN-MW segment primarily consisted of maintenance capital projects, as well as approximately $2 million spent on development capital. Development capital spending primarily related to the conversion of our Vermilion facility to PRB coal. Capital spending in our GEN-NE and GEN-SO segments primarily consisted of maintenance and environmental projects.

We expect capital expenditures for 2007 to approximate $415 million, including the capital expenditures that may be associated with the LS Entities. This primarily includes maintenance capital projects, environmental projects and limited development projects. The capital budget is subject to revision as opportunities arise or circumstances change.

Our capital expenditures in 2007 and beyond will continue to be limited by negative covenants contained in our debt instruments. These covenants place specific dollar limitations on our ability to incur capital expenditures. Please read Note 12 Debt beginning on page F-36 for further discussion of these limitations. Our long term capital expenditures in the GEN-MW segment will also be significantly impacted by the

DMG consent decree which obligates us to, among other things, install additional emission controls at our Baldwin and Havana plants which, based on ongoing engineering estimates, is expected to cost approximately $675 million from 2007 through 2012.

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Financing Trigger Events

Our debt instruments and other financial obligations include provisions which, if not met, could require early payment, additional collateral support or similar actions. These trigger events include leverage ratios and other financial covenants, insolvency events, defaults on scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events.

Commitments and Contingencies

Please read Note 17 Commitments and Contingencies beginning on page F-47, which is incorporated herein by reference, for a discussion of our commitments and contingencies.

Dividends on Common Stock

Dividend payments on our common stock are at the discretion of our Board of Directors. We have not paid a dividend on our common stock since 2002, and we did not declare or pay a dividend on our common stock for the year ended December 31, 2006 and do not foresee a declaration of dividends in the near term due to the dividend restrictions contained in our financing agreements.

Internal Liquidity Sources

Our primary internal liquidity sources are cash flows from operations and cash on hand.

Current Liquidity. The following table summarizes our consolidated revolver capacity and liquidity position at February 22, 2007, December 31, 2006 and December 31, 2005:

	February 22, 2007	December 31, 2006	December 31, 2005
		(in millions)	
Total revolver capacity	$ 470	$ 470	$
Total additional letter of credit capacity	194	194	325(1)
Outstanding letters of credit under credit facility	(195)	(157)	(259)

Unused credit facility capacity	469	507	66
Cash	372(2)	371(2)	1,549(2)(3)
Total available liquidity	$ 841	$ 878	$ 1,615

(1) On April 19, 2006, we entered into a fourth amended and restated credit agreement which consists of (i) a $470 million revolving credit component and (ii) a $200 million letter of credit component. Please read Note 12 Debt Fourth Amended and Restated Credit Facility beginning on page F-36 for further discussion of our amended credit facility. Our credit facility capacity is limited by, and will increase or decrease with changes in cash collateral on deposit.

(2) The February 22, 2007, December 31, 2006 and December 31, 2005 amounts include approximately $41 million, $46 million, and $21 million, respectively, of cash that remains in the Europe and $18 million, $10 million and $19 million, respectively, of cash that remains in the Canada.

(3) The December 31, 2005 amount includes approximately $13 million of cash held by our NGL business. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids beginning on page F-23.

Cash Flows from Operations. We had operating cash outflows of $194 million for the year ended December 31, 2006. This consisted of $698 million in operating cash flows from our power generation business, reflecting positive earnings for the period and increases in working capital due to returns of cash collateral postings. These cash flows were offset by $892 million of cash outflows relating to our customer risk management business and corporate-level expenses. Please read Results of Operations Operating Income and Cash Flow Disclosures for further discussion of factors impacting our operating cash flows for the periods presented.

Our future operating cash flows will vary based on a number of factors, many of which are beyond our control, including the price of natural gas and its correlation to power prices, the cost of coal and fuel oil and the value of ancillary services. Additionally, the availability of our plants during peak demand periods will be required to allow us to capture attractive market prices when available. Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to tightly manage our operating costs, including maintenance costs. Our ability to achieve targeted cost savings in the face of industry-wide increases in labor and benefits costs, together with changes in commodity prices, will impact our future operating cash flows. Please read Results of Operations 2007 Outlook beginning on page 68 for further discussion.

Cash on Hand. At February 22, 2007 and December 31, 2006, we had cash on hand of $372 million and $371 million, respectively, as compared to $1,549 million at the end of 2005. This decrease in cash on hand at February 22, 2007 and December 31, 2006 as compared to the end of 2005 is primarily attributable to cash used for debt repayments, litigation settlements and capital expenditures.

Revolver Capacity. On April 19, 2006, we entered into the Fourth Amended and Restated Credit Facility, replacing the former Third Amended and Restated Credit Facility with a $470 million revolving credit facility, thereby providing the return to DHI of $335 million plus accrued interest in cash collateral securing the former Third Amended and Restated Credit Facility. As of February 22, 2007, $195 million in letters of credit are outstanding but undrawn, and we have no revolving loan amounts drawn under the Fourth Amended and Restated Credit Facility. Please read Note 12 Debt Fourth Amended and Restated Credit Facility beginning on page F-36 for further discussion of our amended credit facility.

External Liquidity Sources

Our primary external liquidity sources are proceeds from asset sales and other types of capital-raising transactions, including public or private equity issuances.

Asset Sale Proceeds. In March 2006, we completed our ownership exchange transactions with NRG which comprised our acquisition of NRG s 50% ownership interest in the entity that owns the Rocky Road power plant (of which we already owned 50%), and the sale to NRG of our 50% ownership interest in the West Coast Power plant, a joint venture between us and NRG, which has ownership in power plants in southern California. As a result of the two transactions, we received cash proceeds of approximately $165 million, net of cash acquired, from NRG. Please read Note 3 Business Combinations and Acquisitions Rocky Road on page F-18 for further discussion. Also, please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations West Coast Power on page F-21 for further discussion.

In November 2006, we completed our sale to Duke Energy Carolinas, LLC (a subsidiary of Duke Energy) (Duke Power) of our Rockingham facility, a peaking facility in North Carolina, which is included in our GEN-SO reportable segment, for $194 million in cash. A portion of the proceeds from the sale were used to repay our borrowings under the $150 million Term Loan, with the remaining proceeds used as an additional source of liquidity. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract

Terminations Rockingham on page F-20 for further discussion. Please read Note 12 Debt Fourth Amended and Restated Credit Facility on page F-36 for further discussion of the Term Loan.

On January 31, 2007, we entered into an agreement to sell our interest in the Calcasieu power generation facility to Entergy for approximately $57 million, subject to regulatory approval. The transaction is expected to

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close in early 2008. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Calcasieu on page F-20 for further discussion.

We are continuing to evaluate our generation fleet based primarily on geographic location, fuel supply, market structure and market recovery expectations. This evaluation will consider the combined portfolio of Dynegy and the LS Entities in anticipation of the pending transaction. Consistent with industry practice, we periodically consider divestitures of non-core generation assets where the balance of the factors described above suggests that such assets earnings potential is limited or that the value that can be captured through a divestiture outweighs the benefits of continuing to own and operate such assets. In conducting our current portfolio review, we are considering, among other things, divesting certain assets that (i) are primarily peaking in nature and generally operate in locations where market recovery is projected to occur much further in the future than in other regions in which we will have a significant asset position, or (ii) could present value propositions through potential dispositions not likely to be achieved through continued ownership and operation by us. As a result of this review, we are considering selling our 614 MW Cogen Lyondell generation facility, our 576 MW Bluegrass generation facility and our 539 MW Heard County generation facility. Moreover, dispositions of one or more other generation facilities could occur in 2007 or beyond. Were any such sale or disposition to be consummated, the disposition could result in accounting charges related to the affected asset(s), and our earnings and cash flows could be affected in 2007 and beyond.

Capital-Raising Transactions. As part of our ongoing efforts to maintain a capital structure that is closely aligned with the cash-generating potential of our asset-based business, which is subject to cyclical changes in commodity prices, we will continuously explore additional sources of external liquidity both in the near- and long-term. The timing of any transaction may be impacted by events, such as strategic growth opportunities, legal judgments or regulatory requirements, which could require us to pursue additional capital in the near-term. In particular, in connection with the pending transaction with the LS Entities, we will be evaluating various opportunities to provide additional liquidity and streamline the combined company s capital structure.

These transactions may include capital markets transactions. The receptiveness of the capital markets to a public offering cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control. Any issuance of equity likely would have other effects as well, including shareholder dilution. Further, our ability to issue debt securities is limited by our financing agreements, including our Fourth Amended and Restated Credit Facility. Please read Note 12 Debt Fourth Amended and Restated Credit Facility beginning on page F-36 for further discussion.

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RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for 2006, 2005 and 2004. At the end of this section, we have included our business outlook for each segment.

We report the results of our power generation business as three separate segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also separately report the results of our CRM business, which primarily consists of the Kendall tolling agreement, the remaining power tolling arrangement (excluding the Sithe toll which is now in our GEN-NE segment and is an intercompany agreement), as well as legacy natural gas, power and emissions trading positions. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. Beginning January 1, 2006, all direct general and administrative expenses are included in Other and Eliminations unless they are specifically identified with the respective segment. This change in allocation methodology is a result of our efforts to better align our corporate cost structure with a single line of business.

As described below, substantially all of our NGL business, which was conducted through DMSLP and its subsidiaries and comprised our NGL reportable segment, was sold to Targa on October 31, 2005. Additionally, as described below, our former REG business, which was conducted through Illinois Power and its subsidiaries and comprised our REG reportable segment, was sold to Ameren Corporation on September 30, 2004.

Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for 2006, 2005 and 2004, respectively.

Year Ended December 31, 2006

	Power Generation					
	GEN-MW	**GEN-NE**	**GEN-SO**	**CRM**	**Other and Eliminations**	**Total**
			(in millions)			
Operating income (loss)	$ 208	$ 55	$ (55)	$ 7	$ (163)	$ 52
Losses from unconsolidated investments			(1)			(1)
Other items, net	2	9	1	4	38	54
Interest expense and debt conversion costs						(631)
Loss from continuing operations before taxes						(526)
Income tax benefit						168
Loss from continuing operations						(358)
Income from discontinued operations, net of taxes						24
Cumulative effect of change in accounting principle, net of taxes						1

Net loss	$ (333)

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Year Ended December 31, 2005

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 194	$ 29	$ (21)	$ (647)	$ (393)	$ (838)
Earnings (losses) from unconsolidated investments	7		(5)			2
Other items, net	2	5	(1)		20	26
Interest expense						(389)
Loss from continuing operations before taxes						(1,199)
Income tax benefit						395
Loss from continuing operations						(804)
Income from discontinued operations, net of taxes						899
Cumulative effect of change in accounting principle, net of taxes						(5)
Net income						$ 90

Year Ended December 31, 2004

Power Generation