DYNEGY INC /IL/
Form 10-K
March 15, 2006
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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, 2005

¨ **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, 2005, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $1,371,862,531 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 304,618,018 shares outstanding as of March 7, 2006; Class B common stock, no par value per share, 96,891,014 shares outstanding as of March 7, 2006.

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 2006 Annual Meeting of Shareholders, which will be filed not later than 120 days after December 31, 2005.

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DYNEGY INC. FORM 10-K

INTRODUCTORY NOTE

This Form 10-K reflects the effect of the restatement of our consolidated balance sheet as of December 31, 2004 and periods prior to 2004 as a result of adjustments to our deferred income tax accounts, as reported in our Annual Report of Form 10-K for the year ended December 31, 2004, which was filed on March 14, 2005.

As previously disclosed in our 2004 Form 10-K, we undertook an evaluation of our tax accounting and reconciliation controls and processes, including a tax basis balance sheet review, which resulted in an adjustment to our deferred tax liability balance. We have since identified mistakes in the tax basis balance sheet review, which totaled an $89 million overstatement of the deferred tax liability balance. Although these mistakes were not considered material, either individually or in the aggregate, to the period to which they related, the mistakes are material, in the aggregate, to our 2005 results. We are required to restate prior periods in accordance with APB 20, Accounting Changes. The item is discussed in more detail in the Explanatory Note to the accompanying consolidated financial statements beginning on page F-10. The following Items of our Form 10-K for the year ended December 31, 2005, are affected by this item:

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

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

Please read Item 9A. Controls and Procedures for a discussion of our control deficiencies related to the deferred income tax accounts and the preparation and review of adjustments to such accounts.

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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-83. 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

General

Our primary business is the production and sale of electric energy, capacity and ancillary services from our 12,638 MW fleet (21 plants) of owned or leased power generation facilities. Our assets are located in the Midwest, New York, Texas 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: (1) primarily through bilateral negotiated contracts with third parties and into regional central markets and (2) with lesser volumes through structured wholesale over-the-counter markets and directly to end-use customers. Our key assets are as follows:

Facility (1)	Total Net Generating Capacity (MW)(2)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Baldwin	1,806	Coal	Baseload	Baldwin, IL	MAIN (MISO)
Havana Units 1-5	242	Oil	Peaking	Havana, IL	MAIN (MISO)
Unit 6	448	Coal	Baseload	Havana, IL	MAIN (MISO)
Hennepin	301	Coal	Baseload	Hennepin, IL	MAIN (MISO)
Oglesby	63	Gas	Peaking	Oglesby, IL	MAIN (MISO)
Stallings	89	Gas	Peaking	Stallings, IL	MAIN (MISO)
Tilton	188	Gas	Peaking	Tilton, IL	MAIN (MISO)
Vermilion	194	Coal/Gas/Oil	Baseload/ Peaking	Oakwood, IL	MAIN (MISO)
Wood River Units 1-3	133	Gas	Peaking	Alton, IL	MAIN (MISO)
Units 4-5	461	Coal	Baseload	Alton, IL	MAIN (MISO)
Rocky Road (3)	182	Gas	Peaking	East Dundee, IL	MAIN (PJM)
Riverside/ Foothills	940	Gas	Peaking	Louisa, KY	ECAR (PJM)
Rolling Hills	970	Gas	Peaking	Wilkesville, OH	ECAR (PJM)
Renaissance	776	Gas	Peaking	Carson City, MI	ECAR (MISO)

Bluegrass	576	Gas	Peaking	Oldham Co., KY	ECAR (MISO)
Total Midwest	*7,369*				
Independence	1,092	Gas	Intermediate	Scriba, NY	NPCC (NYISO)
Roseton	1,210	Gas/Oil	Intermediate	Newburgh, NY	NPCC (NYISO)
Danskammer Units 1-2	130	Gas/Oil	Peaking	Newburgh, NY	NPCC (NYISO)
Units 3-4	371	Coal/Gas/Oil	Baseload	Newburgh, NY	NPCC (NYISO)
Total Northeast	*2,803*				
Calcasieu	347	Gas	Peaking	Sulphur, LA	SERC
Heard County	566	Gas	Peaking	Heard Co., GA	SERC
Rockingham	900	Gas/Oil	Peaking	Rockingham, NC	SERC
Black Mountain (4)	43	Gas	Baseload	Las Vegas, NV	WECC
CoGen Lyondell	610	Gas	Baseload	Houston, TX	ERCOT (ISO)
Total South	*2,466*				
Total Fleet Capacity	*12,638*				

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(1) Does not include facilities owned by West Coast Power (a California-based joint venture co-owned with NRG Energy, Inc.), which owns and operates 1,804 MW of electric generating capacity at three locations in Southern California. On December 27, 2005, we entered an agreement to sell our 50% equity interest in West Coast Power to NRG, subject to regulatory approval, which we obtained on March 1, 2006. The transaction is expected to close in early 2006. For further information, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Overview Company Highlights beginning on page 45.
(2) Unit capabilities are winter ratings as provided to regional reliability councils.
(3) We own a 50% interest in this facility and the remaining 50% interest is held by NRG. Total nameplate capacity of this facility is 364 MW. On December 27, 2005, in connection with our agreement to sell our 50% ownership interest in West Coast Power, we entered into an agreement with NRG to purchase NRG s 50% interest in this facility. For further information, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Overview Company Highlights beginning on page 45.
(4) We own a 50% interest in this facility and the remaining 50% interest is held by Chevron, our significant shareholder. Total output capacity of this facility is 85 MW.

We also have a CRM business. After the termination of the Sterlington tolling agreement on March 7, 2006, the CRM business primarily consists of Kendall, the segment s remaining power tolling arrangement, as well as our legacy physical gas supply contracts, gas transportation contracts and gas, power and emissions trading positions. We report the results of this business as a separate reportable segment.

On October 31, 2005, we sold our other principal business, DMSLP, a natural gas liquids production and marketing enterprise, to Targa Resources.

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 are a holding company and conduct substantially all of our business operations through our subsidiaries.

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 website, 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.

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. We implement a portfolio approach to sales from our facilities whereby 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).

***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 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, fluctuations of which cause power prices to rise and fall typically in tandem. In many 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.

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Hot summer temperatures and cold winter temperatures usually cause increased electricity consumption, driving up prices in affected regions. Conversely, during spring and fall when normal weather is mild, market prices are not usually as extreme.

The impact of supply/demand and weather on market prices can vary based on the market structure in a given region. 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, on a hot summer day, a less-efficient natural gas fired unit may be needed in some hours to meet demand, and production from such unit may cost $100/MWh based on prevailing natural gas prices. If this unit clears the market, each generation unit receives $100/MWh for energy generated, regardless of the price that it or any other unit may have offered into the market.

Production Costs. Another key aspect of profitability is our cost to produce electricity. The main variable component of that cost is fuel that is burned. Our coal-fired generation facilities are our cheapest and most economic facilities. Therefore, most of our coal-fired generation facilities run the majority of a given day throughout the year unless a particular unit is unavailable due to either planned or unplanned maintenance activity. 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 is sufficient to economically justify dispatch of these higher cost units.

We also incur operations and maintenance (O&M) costs. 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.

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 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 capital 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 18 for a discussion of regulatory initiatives that will impact emissions over the longer term.

During 2005, the market price of SO_2 emissions allowances rose to record levels of approximately $1,600 per allowance. The market for these allowances will evolve over the next several years, as power generators pursue capital improvement programs aimed at reducing emissions. While it is not possible to estimate the future economic impact of emissions reduction efforts on the part of market participants, we would expect that the cost of purchasing emissions credits would not remain at levels above the cost of reducing emissions over the long-term.

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The following table summarizes our SO_2 emissions credit positions as of December 31, 2005. Each emissions allowance is expected to cover one ton of emissions. The modeling assumptions include the operation of our coal units at an average capacity factor greater than 82% and limited outages. We have not included estimates beyond 2009, as that will be the year when the first scrubber required by the DMG consent decree is expected to be operational, thus making emissions levels more difficult to project. Additionally, uncertainties with respect to environmental regulations, including the implementation of a two-for-one emissions credit requirement beginning in 2010, make more forward looking estimates difficult to calculate.

SO_2 Emissions (in tons)	2006	2007	2008	2009
Net SO_2 Emissions Allowance Position	39,972	46,335	57,094	64,063

Our corporate Federal NO_x position is expected to end in a surplus in 2006, consisting of banked allowances and unused current vintage allowances; however, this surplus is subject to flow control in future years. In addition, the DMG consent decree imposes certain limitations on the sale or transfer of surplus NO_x allowances.

Services Provided. We sell electric energy, capacity and ancillary services from our facilities. Energy is the actual output of electricity that is measured in megawatt-hours (MWh) at the wholesale level and is usually measured in kilowatt-hours (KWh) at the retail level. Capacity is usually thought of as steel on the ground and is the actual generating unit and its ability to produce energy. Each region must have sufficient generating capacity to meet expected consumption of electricity (known as load). Each region calculates a reserve requirement which is additional necessary capacity that a region must have in order to manage potential unit outages. The capacity of a single generation facility is its electricity production capability, measured in megawatts (MW). 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 Independent System Operators (ISOs). We enter into negotiated contracts for each product or a combination of products with our customers as well.

Customers. Our customers include ISOs, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, industrial customers, power marketers, other power generators and commercial end-users. We sell 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 load.

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 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, primarily fueled with natural gas, 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 oil or 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 2005, we had approximately $143 million in capital expenditures for our entire fleet of

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generation assets, of which $91 million was for maintenance capital, $33 million was for development projects, primarily the conversion of our Vermillion and Havana facilities to PRB coal, and $19 million was for other environmental expenditures.

NERC Regions 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, 2005) 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, ISOs centrally operate markets and transmission across a regional footprint in some of the markets in which we operate. They are responsible for economic and 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. ISOs administer electricity markets for physical and financial energy in the short term, usually day ahead and real-time markets. NERC regions and 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, 2005 **ISO Regions as of December 31, 2005**

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 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 17 for further discussion.

Rates. Our ability to charge market-based rates for wholesale power sales, as opposed to cost-based rates, is governed by the FERC. Substantially all of our facilities currently have the authority to charge market-based rates. 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.

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***Market Structure*.** Our sales of electricity and related services to particular customers and/or at a particular price is subject to the market structure and related rules in the states or regions where we operate. For instance, in organized markets like California and Texas, bids and prices are capped. In part of the New York market, there is a price mitigation procedure. In the State of Illinois, a reverse auction was recently approved by the ICC detailing the process by which Illinois utilities would procure power beginning in 2007.

***SO_2 and NO_x Emissions*.** The Clean Air Act and comparable state laws and regulations require that specified levels of 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. States are required to adopt the federal CAMR or a state rule meeting its minimum requirements. The State of Illinois, where we have significant coal-fired assets, is considering a more stringent rule that would require greater reductions in emissions and thus could entail significant capital expenditures, in each case sooner than would CAMR.

Water Discharge. The Clean Water Act and comparable state laws and regulations govern water discharges associated with our cooling water intake structures. Five of our coal plants and one of our fuel oil plants in Illinois and New York are subject to these rules. We have until 2008 to implement compliance plans under these rules. We are currently involved in litigation and administrative proceedings in New York relating to water discharge permits at our Danskammer and Roseton facilities, each of which could result in material capital expenditures or suspension of plant operations if resolved unfavorably to us.

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, which primarily consists of Kendall, our remaining power tolling arrangement (excluding the Sithe toll which is now in GEN-NE and is an intercompany agreement), as well as several legacy physical gas supply contracts, gas transportation contracts and remaining gas, power and emission trading positions. As described below, our natural gas liquids business, which was conducted through DMSLP and its subsidiaries, was sold to Targa Resources on October 31, 2005. Additionally, as described below, our former regulated energy delivery business, which was conducted through Illinois Power 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, interest and depreciation and amortization.

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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 7,369 MW. Our Midwest fleet as of December 31, 2005 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 (1)	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type	Location	NERC Region and ISO (ISO) (3)
Baldwin	1,806	Coal	Baseload	Baldwin, IL	MAIN (MISO)
Havana Units 1-5	242	Oil	Peaking	Havana, IL	MAIN (MISO)
Unit 6	448	Coal	Baseload	Havana, IL	MAIN (MISO)
Hennepin	301	Coal	Baseload	Hennepin, IL	MAIN (MISO)
Oglesby	63	Gas	Peaking	Oglesby, IL	MAIN (MISO)
Stallings	89	Gas	Peaking	Stallings, IL	MAIN (MISO)
Tilton	188	Gas	Peaking	Tilton, IL	MAIN (MISO)
Vermilion	194	Coal/Gas/Oil	Baseload/ Peaking	Oakwood, IL	MAIN (MISO)
Wood River Units 1-3	133	Gas	Peaking	Alton, IL	MAIN (MISO)
Units 4-5	461	Coal	Baseload	Alton, IL	MAIN (MISO)
Rocky Road (2)	182	Gas	Peaking	East Dundee, IL	MAIN (PJM)
Riverside/ Foothills	940	Gas	Peaking	Louisa, KY	ECAR (PJM)
Rolling Hills	970	Gas	Peaking	Wilkesville, OH	ECAR (PJM)
Renaissance	776	Gas	Peaking	Carson City, MI	ECAR (MISO)
Bluegrass	576	Gas	Peaking	Oldham Co., KY	ECAR (MISO)
Total Midwest	*7,369*				

(1) Unit capabilities are winter ratings as provided to regional reliability councils.
(2) We own a 50% interest in this facility and the remaining 50% interest is held by NRG Energy, Inc. Total nameplate capacity of this facility is 364 MW. On December 27, 2005, we entered into an agreement with NRG to purchase NRG s 50% interest. For further information, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Overview Company Highlights beginning on page 45.
(3) Beginning January 1, 2006, parts of MAIN are now in the SERC region and parts of MAIN and ECAR are now part of the Reliability First region. For further information, please read NERC Regional Alignment Changes in 2006 beginning on page 10.

Starting in 2006, we have completed the final generation facility fuel conversion and will be exclusively burning low-sulfur PRB coal at all Midwest coal facilities. Late in 2004, Havana Unit 6 was converted to PRB and late 2005 Vermilion Units 1 and 2 were converted. PRB coal is a cleaner-burning coal with lower sulfur content, making it more economic to burn while emitting lower amounts of sulfur dioxide.

The conversions to PRB coal have allowed the units to upgrade to new equipment and technologies that are more reliable and allow them to have better operating margins. These upgrades will further enhance the reliability of the unit by allowing more precise control and unit response. For example, in 2005, our Baldwin and Havana stations set all-time records for continuous operations. Our Havana 6 unit set an all-time output record.

All of our Midwest facilities are located either in markets administered by MISO or PJM.

Midwest Fleet in the MAIN/MISO Area

At December 31, 2005, we owned nine generating facilities with an aggregate net generating capacity of 4,107 MW located within MAIN. The MAIN market includes all of Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota and Michigan. The generating capacity of our MAIN facilities represents approximately 6% of the generating capacity within the MAIN region.

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MISO. All of our coal-fired generation in the Midwest is in the MISO market footprint, as are our Renaissance and Bluegrass peaking facilities. MISO operates in all or part of Ohio, Michigan, Indiana, Kentucky, Illinois, Wisconsin, Iowa, Missouri, Minnesota, North and South Dakota, Montana, and parts of Canada. MISO is responsible for least-cost economic dispatch of generation within this market and for maximum utilization of transmission to ensure that the most cost-effective generation reaches the most load within the geographic boundaries of the market. MISO began operating physical and financial energy markets on April 1, 2005. MISO uses a system known as Locational Marginal Pricing (LMP) for energy, which is a system that calculates a price for every generator and load point within the footprint. 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. MISO uses Financial Transmission Rights (FTRs) to allow users to manage transmission congestion and corresponding price differentials across the market area. MISO currently does not have a formal capacity market or ancillary services market. MISO markets are monitored by an independent market monitor responsible for ensuring that 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. The form and timeframe for implementation are uncertain.

MAIN. As of December 31, 2005, the MAIN reliability region had a surplus generation capacity as a result of past competition among merchant plant developers. NERC estimates a 2005 reserve margin of 22%, compared to MISO s 15% to 17% target reserve margin. This overcapacity has historically depressed energy prices in both the MISO market and bilateral capacity sales in the region. This influence may continue until demand growth absorbs excess supply. Based on current expectations of future demand growth and retirements, we believe that reserve margins are likely to return to target levels by 2008 to 2010.

Regulatory Environment. In January 2006, the ICC approved a reverse auction as the process for procuring power beginning in 2007. Under the ICC s Orders, the first auction will occur in September 2006 and will be for almost all of the retail needs of the largest electric utilities in Illinois (Commonwealth Edison Company, and the three Ameren Illinois utilities: Ameren IP, Ameren CIPS and Ameren CILCO). 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. There remains the possibility of substantial challenges to the auction process. Among others, the Governor and Attorney General (who has been an active party in the regulatory proceedings) have announced their opposition to the auctions. In addition, at least one bill has been introduced in the Illinois General Assembly to extend the rate freeze in effect beyond the end of this year, which may have an impact on the auctions. Therefore, there is a possibility of political, legislative, judicial and/or regulatory actions over the next several months that could alter substantially, or even eliminate altogether, the auctions. Given these uncertainties, the effect of the final process that will be used in Illinois cannot be predicted at this time.

Contracted Capacity. In connection with our sale of Illinois Power to Ameren in the third quarter 2004, we entered into a contract to sell to Illinois Power 2,800 MW of capacity at $48 per KW-yr and up to 11.5 million MWh of energy at a fixed price of $30 per MWh for two years beginning in January 2005. We also agreed to sell 300 MW of capacity in 2005 and 150 MW of capacity in 2006 to Illinois Power at a fixed price of $16 per KW-yr with an option to purchase energy at market-based prices.

In addition to capacity committed under our contract with Ameren, approximately 27% of our total capacity in the MISO area of the region will be sold under other bilateral capacity contracts in 2006. In PJM, where capacity is sold via the robust over-the-counter capacity market as well as through capacity auctions held by PJM, we sell substantially all of our capacity each year, including 330 MW from Rocky Road through 2009. The remainder of capacity and energy is sold primarily into wholesale markets.

Environmental Considerations. Since November 1999, portions of our Midwest coal-fired fleet had been subject to a Notice of Violation (NOV) from the EPA and a complaint filed by the EPA and the DOJ in federal district court alleging violations of the Clean Air Act and related federal and Illinois regulations related to certain

maintenance, repair and replacement activities at our Baldwin generating station. In 2005, after a trial in the U.S. District Court for the Southern District of Illinois, we reached agreement with the EPA, the DOJ, the State of Illinois and the environmental group intervenors on terms to settle the litigation. A consent decree was finalized in July. 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 estimate, based upon ongoing engineering estimates, will cost $611 million through 2013.

Please read Regulatory and Environmental Matters beginning on page 17 for further discussion of the environmental and regulatory restrictions applicable to our business.

Midwest Fleet in the ECAR Area

At December 31, 2005, we owned interests in four generating facilities with an aggregate net generating capacity of 3,262 MW located within ECAR. The majority of power generated by our ECAR facilities is sold to wholesale customers in the ECAR market, which includes all or portions of the states of Indiana, Ohio, Michigan, Virginia, West Virginia, Tennessee, Kentucky, Maryland and Pennsylvania. Generating capacity of our ECAR facilities represents approximately 2% of generating capacity within the region.

PJM. Three of the ECAR reliability region facilities Rocky Road, Rolling Hills, and Riverside/Foothills operate within geographic boundaries of the PJM market. PJM s geographic area has significantly expanded in the past two years, including addition of AEP and ComEd service areas. PJM now encompasses all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM currently administers markets for wholesale electricity and provides transmission planning for the region, and utilizes 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. PJM s markets are overseen by an independent market monitor who continually monitors markets for manipulation or improper behavior by any entity. PJM has proposed changes to its capacity markets, including establishing longer-term markets for capacity to improve market signals for new generation, and these proposals are currently being debated by market participants. Form and timing of final market design changes is indeterminate.

ECAR. The ECAR region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2005 reserve margin of 26% as compared to a target reserve margin of 15%. MISO has indicated that it will enforce the current reserve requirement in each Reliability Region (i.e., MAIN, ECAR and MAPP) until such time that a capacity market is implemented. The reserve requirement to apply during the period following establishment of such capacity market has not been determined. This overcapacity has depressed energy and capacity values in this region and may continue to do so until demand growth absorbs surplus capacity. However, based on current expectations of future demand growth and retirements, we believe that reserve margins are likely to return to target levels within 2008 to 2010.

Contracted Capacity. In July 2004, we entered into an agreement with a term from June 2005 through May 2006 to sell 500 MW of capacity from our peaking facilities in the ECAR region. Additionally, we have contracted to sell 240 MW of capacity from our Bluegrass facility from January through December 2006.

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NERC Regional Alignment Changes in 2006

As of January 1, 2006, the NERC regions of MAIN, MACC, and ECAR have merged to become Reliability First Corporation. Ameren, the parent company of Illinois Power in whose control area all of our coal-fired units reside (previously part of MAIN), chose not to join Reliability First and instead chose to join the Southeastern Electric Reliability Council (SERC). Therefore, beginning January 1, 2006, our new NERC regional alignment will be as follows:

Ameren Illinois Power Control Area SERC	Reliability First Market Area MAIN, MACC, ECAR
Baldwin (IL) MISO Market	Rocky Road (Chicago, IL) PJM Market
Havana (IL) MISO Market	Bluegrass (KY) MISO Market
Hennepin (IL) MISO Market	Riverside/Foothills (KY) PJM Market
Oglesby (IL) MISO Market	Rolling Hills (OH) PJM Market
Stallings (IL) MISO Market	Renaissance (MI) MISO Market
Tilton (IL) MISO Market	
Vermilion (IL) MISO Market	
Wood River (IL) MISO Market	

Power Generation Northeast Segment

Our Northeast fleet comprises three facilities located in two counties in New York. We own the Independence power generating facility, and we lease two generating facilities, Roseton and Danskammer. 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 2,803 MW, which represents approximately 7% of New York s generating capacity.

Facility (1)(2)	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type	Location	NERC Region (ISO)
Independence	1,092	Gas	Intermediate	Scriba, NY	NPCC (NYISO)
Roseton (3)	1,210	Gas/Oil	Intermediate	Newburgh, NY	NPCC (NYISO)
Danskammer Units 1-2	130	Gas/Oil	Peaking	Newburgh, NY	NPCC (NYISO)
Units 3-4 (3)	371	Coal/Gas/Oil	Baseload	Newburgh, NY	NPCC (NYISO)
Total Northeast	*2,803*				

(1) Unit capabilities are winter ratings as provided to regional reliability councils.
(2) 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-39.
(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 52.

NYISO. All facilities are located in the New York Independent System Operator (NYISO) area. NYISO administers statewide transmission system and spot markets for electricity and calculates electricity prices and dispatches generation using an LMP model. NYISO also administers markets for capacity and certain ancillary services. NYISO has an independent market monitor that continuously checks to ensure that markets are free from manipulation and are operating properly. 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 2005-2006), the estimated cost of new entrant generation, estimated peak demand, and the actual amount of capacity bid into the market. The

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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.

For New York, FERC has approved and extended indefinitely an Automated Mitigation Procedure, or AMP, that caps real-time bid prices based on cost characteristics of power generating facilities in NYISO. However, in June 2005, FERC required NYISO to eliminate tariff provisions that would have applied AMP in day-ahead market in the area outside New York City and Long Island. FERC s decision was based on an opinion issued January 2005 by the U.S. Court of Appeals for the District of Columbia Circuit that vacated and remanded the FERC s orders approving the AMP in the day-ahead market outside of New York City. In September 2005, FERC similarly required the NYISO to eliminate tariff provisions that would have applied AMP in the real-time market in the area outside New York City. However, FERC permitted NYISO to retain tariff provisions that provide for use of Real Time Software to apply conduct and impact mitigation on an interval by interval basis after appropriate consultation with the relevant market participant.

NPCC. 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 21% are somewhat above the NYISO s target reserve margin of 18%. Reserve margins are likely to return to target levels by 2008 to 2010.

Contracted Capacity. Approximately 72% 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 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 short-term and for the foreseeable future.

Environmental and Regulatory Considerations. Our Northeast assets may be subject to a state-driven program known as the Regional Greenhouse Gas Initiative (RGGI). RGGI is a program under development by seven New England and Mid-Atlantic states to cap and trade carbon dioxide emissions from power plants. As currently proposed, affected generators will have a variety of options to comply with RGGI. Generators can reduce their emissions through efficiency measures, fuel switching, or through the implementation of new technologies. Any excess allowances thus generated could then be sold. Generators can also purchase allowances to cover a portion of their emissions as a compliance strategy, if they emit more carbon dioxide than their initial allocation of allowances would permit. 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.

At this time, administrative proceedings and litigation specific to water discharges issues at two of our New York facilities are ongoing. For further discussion of these matters, please see Note 18 Regulatory Issues Roseton State Pollutant Discharge Elimination System Permit beginning on page F-65 and Note 18 Regulatory Issues Danskammer State Pollutant Discharge Elimination System Permit beginning on page F-66, respectively.

Please read Regulatory and Environmental Matters beginning on page 17 for further discussion of the environmental and regulatory restrictions applicable to our business.

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Power Generation South Segment

Our South fleet comprises three natural gas-fired peaking facilities, and two natural gas-fired cogeneration facilities totaling 2,466 MW of electric generating capacity. Key details of the South fleet are as follows:

Facility (1)(2)(3)	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type	Location	NERC Region
Calcasieu	347	Gas	Peaking	Sulphur, LA	SERC
Heard County	566	Gas	Peaking	Heard Co., GA	SERC
Rockingham	900	Gas/Oil	Peaking	Rockingham, NC	SERC
Black Mountain (4)	43	Gas	Baseload	Las Vegas, NV	WECC
CoGen Lyondell	610	Gas	Baseload	Houston, TX	ERCOT (ISO)
Total South	2,466				

(1) Does not include facilities owned by West Coast Power (a California-based joint venture co-owned with NRG), which owns and operates 1,804 MW of electric generating capacity at three locations in Southern California. On December 27, 2005, we entered an agreement to sell our 50% equity interest in West Coast Power to NRG. We have received FERC approval to close this transaction, and the transaction is expected to close in early 2006.
(2) Does not include facilities associated with our 50% ownership interest in a generating facility located in Panama.
(3) Unit capabilities are winter ratings as report to regional reliability councils.
(4) We own a 50% interest in this facility and the remaining 50% interest is held by Chevron, our significant shareholder. Total output capacity of this facility is 85 MW.

South Fleet in the SERC Area

Our Calcasieu, Heard County, and Rockingham facilities (aggregate net generating capacity of 1,813 MW) are located in SERC. SERC territory includes all or portions of the states of Missouri, Kentucky, Arkansas, Tennessee, West Virginia, Virginia, North Carolina, South Carolina, Louisiana, Mississippi, Alabama and Georgia. The generating capacity of these facilities represents approximately 1% of the generating capacity in SERC.

Our 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.

SERC. 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. Overcapacity is less severe in the Virginia-Carolinas area (VACAR) sub-region of SERC (where the Rockingham facility is located), and we believe market conditions there may require new capacity additions by 2009 to 2011.

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Contracted Capacity. Given the Southeast s regulated market structure, these three plants principally sell capacity to the local regulated utilities and energy and ancillary services through bilateral transactions with the utilities and wholesale buyers. Total capacity committed under firm sales arrangements are as follows:

Southeast Capacity Sold Under Contract

Year	Calcasieu	Heard County	Rockingham	Total % Sold
2006	320 MW	495 MW	430 MW	69%
2007	320 MW	495 MW	380 MW	66%
2008	160 MW	495 MW	380 MW	57%
2009	160 MW	495 MW	215 MW	48%
2010		495 MW	215 MW	39%
2011		495 MW		27%
2012		495 MW		27%
2013		495 MW		27%
2014		495 MW		27%
2015		495 MW		27%

South Fleet in the ERCOT Area

Our CoGen Lyondell facility (net generating capacity of 610 MW) is located in Electric Reliability Council of Texas (ERCOT) comprising a majority of the state of Texas. This facility represents less than 1% of generating capacity in the ERCOT region.

This market is administered by ERCOT ISO, which oversees competitive wholesale and retail markets. ERCOT s operations are overseen by the Public Utility Commission of Texas (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 locational-based marginal pricing (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 circa 2009.

The ERCOT region currently has surplus generation capacity indicated by a NERC estimated 2005 reserve margin of 17%, exceeding ERCOT s target minimum reserve margin of 12.5%. This overcapacity has historically depressed energy and capacity values in this region. However, recently released reports from ERCOT indicate that reserve margins may fall below the 12.5% level by 2010 to 2013 due to recently announced generating retirements and mothballed units.

Contracted Capacity. The CoGen Lyondell facility since its inception has sold steam and 70 MW of capacity and energy to its site host, Lyondell Chemical Company, under long-term contracts expiring in December 2006. On September 6, 2005, we entered into an agreement to extend steam and energy sales to Lyondell. Under the new agreement, we will 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 530 MW) are sold through bilateral transactions or through the ERCOT daily market.

Environmental Considerations. The Cogen Lyondell facility is currently installing Dry-Low NO_x emissions reduction controls at a cost of around $21.5 million to satisfy Houston-area ozone rules, and when completed the air permit will be renewed in early 2007. With these improvements, the facility is expected to be in full environmental compliance for the foreseeable future.

South Fleet Equity Investments

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

West Coast Power. During 2005, we were a 50% owner of West Coast Power (a California-based joint venture co-owned with NRG Energy, Inc.) which owns and operates 1,804 MW of electric generating capacity at three locations in Southern California. This fleet operates completely within the confines of the Cal ISO wholesale market (in the Western Electricity Coordinating Council (WECC) region of NERC). Key details on our share of the West Coast Power electric generation fleet are as follows:

Facility	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type	Location
Cabrillo I Encina (1)	480	Gas	Intermediate	Carlsbad, CA
El Segundo (1)	335	Gas	Intermediate	El Segundo, CA
Cabrillo II (1)	87	Gas	Peaking	San Diego, CA
Total West Coast Power	902			

(1) We own a 50% interest in each of these facilities. The 100% nameplate capacity of the West Coast Power fleet is 1,804 MW. West Coast Power also owns the Long Beach Generating Station within the Port of Long Beach, California which was retired as of 12/31/2004.

On December 27, 2005, we entered an agreement to sell our 50% equity interest in West Coast Power to NRG Energy for approximately $205 million, and the transaction is expected to close in early 2006. For further information, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Overview Company Highlights beginning on page 45.

Panama. In addition to our U.S. generating assets, as of December 31, 2005, we owned a 50% interest in a generating facility located in Panama. Since the expiration of a capacity contract in January 2005, this facility has been operating on a merchant basis. In December 2005, we entered into an agreement to sell our interest in this generating facility. Since January 2006, approximately 2/3 of the facility s output has been sold under contract.

Customer Risk Management Segment

After the termination of the Sterlington tolling agreement on March 7, 2006, the CRM business primarily consists of Kendall, the segment s remaining power tolling arrangement, as well as our legacy physical gas supply contracts, gas transportation contracts and 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. In addition to this tolling arrangement, our CRM segment includes physical gas supply contracts, gas transportation contracts and remaining gas, power and emission trading positions. We are actively pursuing opportunities to terminate, assign or renegotiate terms of our contractual obligations remaining under these agreements when circumstances are economically advantageous to us.

Power Tolling Arrangements. In December 2005, we announced that we had agreed to terminate the Sterlington long-term wholesale power tolling contract with Quachita Power LLC. Under the terms of the agreement, we paid Quachita Power LLC, a joint venture of GE Energy Financial Services and Cogentrix Energy, Inc., approximately $370 million to eliminate approximately $456 million in capacity payment obligations through 2012 and approximately $295 million in additional capacity payment obligations that would arise if Quachita exercised its option to extend the contract through 2017. The termination became effective on March 7, 2006.

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With respect to our remaining toll in CRM, Kendall, we have mitigated the effect of such tolling arrangement through November 2008 by entering into a back-to-back power purchase agreement with a subsidiary of Constellation Energy, whereby we will receive payments which offset our obligations to LSP-Kendall. Pursuant to this arrangement, we are obligated to make aggregate payments of approximately $457 million to LSP-Kendall in exchange for access to power generated by their facilities, resulting in a total obligation of $335 million, net of $122 million to be received from Constellation over the next 35 months.

Legacy Marketing and Trading. Regarding our legacy 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.

Gas As of December 31, 2005, we have exited a significant portion of our physical and financial gas marketing and trading business. We expect to have substantially exited this business by the end of 2007, with the exception of a minimal number of physical 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 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 Our remaining CRM power business, exclusive of our remaining power tolling arrangements, is expected to be substantially exited by the end of 2006, 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 impose volatility in our statement of operations as prices change during the year. We currently anticipate that these transactions will be cash flow positive for 2006 on an aggregate basis. We will continue our efforts to exit the remaining transactions as allowed by market liquidity, credit requirements, and market opportunities.

Emissions We have forward obligations to deliver SO_2 emissions allowances in 2006, 2007 and 2008. Our financial statements reflect the gain or loss on these obligations resulting from the price fluctuation in SO_2 emissions allowances. These obligations are hedged by an 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 obligations, we will recognize gains 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 third parties make payment for the emissions allowances. The inventory of emissions allowances that we use to fulfill our forward obligations is separate from the inventory and needs of our Power Generation business.

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, 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-27 for further discussion. This segment had both upstream and downstream components. The upstream components included natural gas gathering and processing; while the downstream components included fractionating, storing, terminalling, transporting, distributing and marketing natural gas liquids.

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

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Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23 for further discussion. This segment was engaged in the transmission, distribution and sale of electric energy and the distribution, transportation and sale of natural gas in the state of Illinois. It included retail electric and natural gas service to residential, commercial and industrial consumers in substantial portions of northern, central and southern Illinois and also supplied electric transmission service to electric cooperatives, municipalities and power marketing entities in the state of Illinois.

Other

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

The communications business was established during the fourth quarter 2000 and included an optically switched, mesh fiber-optic network with more than 16,000 route miles that reached 44 cities in the United States. During the first quarter 2003, we sold our European communications business, which operated a high-capacity, broadband network with access points in 32 cities throughout Western Europe. During the second quarter 2003, we sold our U.S. communications business. Since we have completed our exit from the global communications business, we do not expect that this business will be included in our Other results for future periods.

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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 authority for our exempt wholesale generator facilities, which includes 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 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 scheduled for mid-2008. The FERC has adopted market behavior regulations and, more recently, other regulations modeled after the SEC s Rule 10b-5, designed to prohibit market manipulation. A violation of these regulations could result in the revocation or suspension of our market-based authority, as well as disgorgement of profits and potential penalties. Please read Note 18 Regulatory Issues beginning on page F-64 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. Please read Segment Discussion beginning on page 6 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 generally in a safe and environmentally responsible manner. This can be challenging because, among other reasons, the regulatory landscape is constantly changing 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, in many cases, significant capital and operating expenditures.

Our aggregate expenditures for compliance with laws and regulations related to the protection of the environment associated with our power generation fleet were approximately $56 million in 2005, compared to approximately $25 million in 2004 and approximately $51 million in 2003. In 2005, our expenditures include $27 million associated with the conversion of our Vermilion and Havana facilities to PRB coal. We estimate that total environmental expenditures (both capital and operating) in 2006 will be approximately $67 million. These expenditures are exclusive of the civil penalty and environmental mitigation projects required by the Baldwin consent decree discussed above. In 2006, the projected costs are associated primarily with enhanced air pollution controls, and handling of combustion byproducts. Changes in environmental regulations or outcomes of litigation, including our ongoing New York State Pollution Discharge Elimination System (SPDES) litigation involving Danskammer and the SPDES Permit renewal proceedings involving Danskammer and Roseton, could result in additional requirements that would necessitate increased future spending and potentially adverse operating conditions.

Following is a summary of material environmental, health and safety matters impacting our business.

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

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operations previously 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 $21.5 million through 2007 pursuant to such plans.

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 substance found at a facility. CERCLA also authorizes the 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 such responsible party. 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 corrected timely. We believe we currently comply and expect to continue to comply in all material respects with applicable rules and regulations.

Ongoing and Future Environmental Initiatives. Current and proposed legislation and rulemaking contains 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 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 Illinois current consideration of a state rule that would require greater mercury emission reductions and in a shorter time period than the federal Clean Air Mercury Rule (CAMR).

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 ($PM_{2.5}$) 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 becomes effective in 2009; the SO_2 control program becomes effective in 2010. The final compliance phase begins in 2015. With respect to SO_2 emissions, CAIR will require the use of two emission credits for each ton of emissions beginning in 2010 and 2.87 emission credits for each ton of emissions beginning in 2015. In August 2005, the Administrator of the Federal EPA published a proposed rule that includes a federal implementation plan (FIP) to reduce transport of fine particulate matter and ozone, modeled after CAIR.

CAMR will permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade program. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. CAMR imposes a national cap on mercury emissions from coal-fired power plants of 38 tons by 2010 and 15 tons by 2018, down from the estimated 48 tons emitted in 1999. In October 2005, the Federal EPA announced its decision to reconsider several issues in connection with CAMR, including the impacts associated with implementation of an emissions cap-and-trade program.

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 SIPs to address regional haze. SIP 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 CAIR requirements for BART controls otherwise required by SIPs under CAVR. In July 2005, EPA also issued a proposed rule detailing requirements for an emissions trading program that can satisfy BART requirements for regional haze program for non-CAIR states.

The latest revisions to the CAIR, CAMR and CAVR have not caused us to significantly revise our original estimates of capital investments necessary to achieve compliance with these requirements. In general, requirements of these rules would require compliance to be achieved either by installation of pollution controls, purchase of emission allowances, curtailment of operations or some combination thereof. However, the final rules give states substantial discretion in developing their rules to implement these programs and states will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. In addition, CAIR, CAMR and CAVR have been challenged in the federal courts. As a result, ultimate state requirements may not be known for several years and may depart significantly from rules described here. If final rules are remanded by the court, if states elect not to participate in the federal cap-and-trade programs, and/or if states elect to impose additional requirements on individual units that are already subject to CAIR, CAVR and/or CAMR, our costs could increase significantly.

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 power generating facilities, as well as other industries, if adopted 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, none have advanced through the legislature and there are presently no federal mandatory greenhouse gas reduction requirements. The likelihood of any federal mandatory

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carbon dioxide emissions reduction program being adopted in the near future, and the specific requirements of any such program, are uncertain. However, a number of states in the Northeast and the West 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.

Water Issues. Our wastewater discharges are permitted under the Clean Water Act and analogous state laws. EPA s Phase II rule under Section 316(b) of the Clean Water Act established national standards aimed at protecting aquatic life at power generating facilities with existing cooling water intake structures. Five of our coal and one our fuel-oil fired facilities in Illinois and New York are affected sources under the rule. 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.

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 station discharge limits and could require our facilities to install additional water treatment equipment.

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COMPETITION

Demand for power may be met by generation capacity based on several competing technologies, such as gas-fired, coal-fired or nuclear generation and 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 various businesses in which we operate. These risks include, but are not limited to, equipment breakdowns or malfunctions, explosions, fires, terrorist attacks, product spillage, weather, nature, 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 increased significantly during recent periods, and may continue to do 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.

In our CRM segment, we also face market, price, credit and other risks relative to our exit from the CRM business. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 85 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 the 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 in the industries in which we compete and to financial loss. Please read Item 9A. Controls and Procedures beginning on page 87 for further discussion of our internal control systems.

SIGNIFICANT CUSTOMER

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 years ended December 31, 2003 and 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 2005, 2004 or 2003.

EMPLOYEES

At December 31, 2005, we had approximately 354 employees at our administrative offices and approximately 1,017 employees at our operating facilities. Approximately 637 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions. 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:

- projected operating or financial results, including anticipated cash flows from operations;
- expectations regarding capital expenditures, interest expense and other payments;
- beliefs about commodity pricing;
- strategies to capture opportunities presented by rising commodity prices and strategies to manage our risk exposure to energy price volatility while reducing our hedging;
- plans to achieve fuel-related, general and administrative, and other targeted cost savings;
- beliefs and assumptions relating to our liquidity position, including our ability to satisfy or refinance our significant 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 or 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;
- coal and fuel oil inventories;

beliefs about the outcome of legal and administrative proceedings, including the matters involving the western power and natural gas markets, master netting agreement matters, and the investigations primarily relating to past trading practices;

assumptions about prospective regulatory developments;

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

application of the proceeds from the sale of DMSLP;

positioning our generation business for future growth; and

measures to complete our exit from the CRM 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

Future changes in commodity prices may materially adversely impact our financial condition, results of operations and cash flows.

The price we can obtain for the sale of power may not rise at the same rate, or may not rise at all, to match a rise in fuel costs. Our profitability depends in large part on the difference between the price of power and the price of fuel used to generate power, or spark spread . Prices for both electricity and fuel have been very volatile in the past year and the prices for electricity, coal, natural gas and fuel oil are significantly higher than they were two years ago. Changes in market prices for natural gas, coal and fuel oil may result from many factors, including the following:

- weather conditions, including deviations from average temperatures and major weather events, such as hurricanes;
- seasonality;
- demand for energy commodities and general economic conditions, including the demand for fuel;
- disruption of electricity, gas or coal transmission or transportation, storage, infrastructure or other constraints or inefficiencies;
- the addition of new generating capacity or the retirement of existing generating capacity, or the temporary unavailability of generating capacity for maintenance and other reasons;
- availability of competitively priced alternative energy sources;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil, refined products and coal production levels;
- the creditworthiness or bankruptcy or other financial distress of market participants;
- changes in market liquidity;
- natural disasters, wars, embargoes, acts of terrorism and other catastrophic events; and

federal, state and foreign governmental regulation and legislation including regulatory-imposed price caps.

Adverse changes in market prices for fuel, and a resulting negative impact on market prices for power, could materially adversely impact our financial condition, results of operations and cash flows.

Because our power generation facilities operate mostly without long-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 long-term sales agreements. Without long-term power 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 short-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.

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Given the volatility of power commodity prices, to the extent we do not secure long-term 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.

Because we generally do not hedge our long-term exposure to commodity price risks, we are vulnerable to decreases in power prices and increases in the price of natural gas, coal and fuel oil. To the extent we do engage in hedging activities, our models representing the market may be inaccurate.

We generally do not hedge our long-term exposure to commodity price risks. To the extent we are unable to mitigate our exposure to a diminishing spark spread, our financial condition, results of operations and cash flows may be materially adversely affected. In those instances where we do implement a hedging strategy, 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.

Although we are exiting the CRM business, and have adopted a strategy of entering into only limited hedges of our generation output, we continue to enter into some primarily short-term hedging and other risk management transactions relating to our physical production. We have adopted various internal policies and procedures designed to monitor these activities and positions to ensure that we maintain an overall position that is substantially balanced between our physical assets as compared to our purchase and sales commitments. 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.

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 purchase their fuel requirements under short-term contracts or on the spot market. Although we attempt to purchase fuel based on our known fuel requirements, we still 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.

Operation of many of our coal-fired generation facilities is highly dependent on our ability to procure coal. Power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. While we believe our physical inventories and contractual commitments provide us with a stable coal supply, we are subject to physical delivery risks outside of our control. 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.

In the ordinary course of operating our power generating facilities, we maintain, either by allocation or purchase, sufficient emission credits to support our operations. We use these credits to comply with emission caps imposed by various environmental laws under which we must operate. As individual credits are used, costs are recognized as operating expense. If we are unable to purchase sufficient emission credits to match our operational needs, we may have to curtail our operations such that we do not exceed our permitted emission caps. 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.

Competition in wholesale power markets, together with an oversupply of power generation capacity, 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, as well as 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 services and transportation services. Aggregate demand for power may be met by generation capacity based on several competing technologies, such as gas-fired, coal-fired or nuclear generation, 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.

Although demand for electric capacity and energy generally has been increasing throughout the United States, a buildup of new electric generation facilities in recent years has resulted in an overabundance of power generation capacity in the 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 vintage plants owned by competitors are often 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. A number of generation facilities in the United States are now in the hands of lenders and investment companies. Furthermore, there have been several important mergers and asset reallocations in the industry, which could create powerful new competitors. Under any scenario, we anticipate that we will continue to face competition from numerous companies in the industry some of which have superior capital structures. 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 are discontinuing their unregulated activities, seeking to divest their unregulated subsidiaries or 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.

We anticipate that FERC will continue its efforts to facilitate the competitive energy marketplace throughout the country on several fronts but particularly by encouraging utilities to voluntarily participate in RTOs and ISOs, while state regulators will pursue their own initiatives. FERC is also reviewing ways in which it can encourage investment in transmission facilities and reform the rules and regulations governing access to the transmission grid, all of which could increase the number of competitors serving a given market. FERC s regulation of wholesale markets including changes in the manner in which transmission rates are calculated, also could affect our competitive posture. These regulatory initiatives may include significant revisions to existing regulation of the electric utility industry or selected products and services in some markets. Industry deregulation and privatization may not only continue to facilitate the current trend toward consolidation in the utility industry but also may encourage disaggregation of other vertically integrated utilities into separate generation, transmission and distribution businesses. As a result, our industry may be restructured with new kinds of specialized companies competing with us. We may not be able to respond in a timely or effective manner to the many changes in the power industry that may occur as a result of regulatory initiatives to increase competition. We are not able to predict future changes in regulation or the effect of any such changes on the general electricity market or our financial condition, results of operations and cash flows.

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If we fail to implement our business strategy, our financial condition, results of operations and cash flows could be materially adversely affected.

Our future financial condition, results of operations and cash flows will depend in large part upon our ability to successfully implement our business strategy. Implementation of our business strategy could be affected by a number of factors beyond our control, such as increased competition, legal and regulatory developments, general economic conditions and energy price volatility in either electricity or fuel markets. As a result, we cannot be sure that we will be able to successfully implement our business strategy. In particular, we cannot be sure that we will be able to identify and pursue growth opportunities. Our ability to achieve our growth objectives and to effectively manage our growth will depend on a number of factors, including:

- our liquidity, including any collateral posting requirements to which we are subject, and our ability to attract capital and financing on acceptable terms;
- our ability to identify and pursue appropriate opportunities for growth; and
- our ability to integrate any new businesses into our operations and take advantage of potential synergies.

Any failure to successfully implement our business strategy could materially adversely affect our financial condition, results of operations and cash flows. We may, in addition, decide to alter or discontinue certain aspects of our business strategy from time to time due to our success or failure in the marketplace.

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 our current power purchase agreement with AmerenIP, which expires at the end of 2006, our Midwest coal plants are partially contracted to AmerenIP at a fixed price per megawatt hour. Beyond 2006, our results in the Midwest will be exposed to volatility in market prices which could cause us to realize losses in a weak power price environment. For the year ended December 31, 2005, approximately 20% of our consolidated revenues were derived from transactions with AmerenIP.

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. 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. Furthermore, the rates for such transmission capacity are set by others and the market and thus are subject to changes, some of which could be significant. Transmission may not be available to support our contracted and short-term transactions, or the costs of such transmission may reduce our profits or make certain transactions unprofitable. Furthermore, 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.

Our results of operations fluctuate on a seasonal and quarterly basis due to weather conditions.

We have historically sold less power and received lower prices for our products, and consequently earned less income, when weather conditions are milder. We expect that unusually mild weather in the future could

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diminish our results of operations and impair our financial condition. Weather conditions can affect both the prices we pay for fuel and the prices we receive for capacity, energy and other services, potentially increasing the volatility of our results of operations.

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 for approximately $920 million four of six generating units comprising these facilities 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 the applicable lessee 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, 2005, the termination payment would be approximately $1 billion for all of our DNE facilities. If a termination of this type were to occur with respect to all of the DNE facilities, it could be difficult for us to raise sufficient funds to make this termination payment and therefore could have a material adverse effect on our financial conditions, results of operations and cash flows.

Refurbishment and operation of power generation facilities involve significant risks that cannot always be covered by insurance or contractual protections and could have a material adverse effect on our financial condition, results of operations and cash flows.

We are exposed to risks related to breakdown or failure of equipment and processes, shortages of equipment and supply of material and labor, and operating performance below expected levels of output or efficiency. Older equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep it operating at optimum efficiency. This equipment is also likely to require periodic upgrading and improvement. Any unexpected failure, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures could result in reduced profitability. In addition, if we make any major modifications to our power generation facilities, as defined under the new source review provisions of the federal CAA, we may be required to install best available control technology or to achieve the lowest achievable emissions rate. Any such modifications would likely result in substantial additional capital expenditures.

In addition, at some point, older facilities may need to be retired or decommissioned. The costs of decommissioning can be affected by future changes in law and regulations, as well as deviations from the expected physical state of such facilities. Therefore, we cannot be certain that we have adequately predicted, or reserved for, the full costs of any such retirements or decommissionings.

We cannot predict the level of capital expenditures that will be required due to changes in applicable reliability requirements, deteriorating facility conditions and unexpected events (such as natural disasters or terrorist attacks). The unexpected requirement of large capital expenditures could have a material adverse effect on our financial condition, results of operations and cash flows. Further, construction, expansion, modification and refurbishment of power generation facilities may interrupt production at our facilities or result in unanticipated cost overruns and may be impacted by factors outside our control, including:

- supply interruptions;

work stoppages;

labor disputes;

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weather interferences; and

unforeseen engineering, environmental and geological problems.

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

We are subject to all risks inherent in the power generation industry. These risks include, but are not limited to equipment breakdowns or malfunctions, explosions, fires, terrorist attacks, product spillage, weather, nature, 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. Costs associated with these insurance coverages have increased significantly during recent periods and may continue to do so in the future. Occurrence of a significant event not fully insured or otherwise indemnified against by a third party, or the failure of a party to meet its indemnification obligations, could materially adversely affect our financial condition, results of operations and cash flows. 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 maintain or secure these levels and types of insurance in the future could have a material adverse effect on our financial condition, results of operations and cash flows if an uninsured loss were to occur. No assurance can be given that we will be able to secure or maintain these levels of insurance in the future at rates we consider commercially reasonable.

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, which may negatively impact our results of operations.

We are subject to extensive federal, state and local laws and regulations governing generation and sale of energy commodities, as well as discharge of materials into the environment and otherwise relating to the environment, health and safety protection. Compliance with these laws and regulations requires general and administrative expenses (including legal representation before agencies) and monitoring, capital and operating expenditures, including those related to pollution control equipment, emission fees, 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.

FERC has issued a series of rules and proposed rules to implement provisions of the Energy Policy Act of 2005 which affect electric and natural gas industries. These rules and proposed rules include changes in FERC s review of mergers in the electricity sector, new provisions governing reliability in the electric sector, increased civil and criminal penalties for violations of relevant statutes and regulations and new regulations defining prohibited behavior and practices. FERC is also reviewing ways in which it can encourage investment in the transmission grid, changes in the rules governing access to that grid, and the operations of wholesale markets generally. These changes, combined with the repeal of the Public Utility Holding Company Act of 1935, will create further regulatory uncertainty.

Our costs for compliance with 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

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regulations may be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions. Proposals currently under consideration, such as pending state and federal EPA regulatory proposals to regulate mercury emissions under Section 112 of the Clean Air Act or bills pending in Congress which would limit emissions of carbon dioxide and other so-called greenhouse gases, could, if and when adopted or enacted, require us to make substantial new capital and operating expenditures. If any of these events occur, our business, operations and financial condition could be materially adversely affected.

Many environmental laws require approvals or permits from governmental authorities 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 either 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 are constructing, modifying and operating our facilities. Certain of our facilities, including our Baldwin facility, are also required to comply with the terms of consent decrees or other governmental orders. A consent decree relating to violations of the Clear Air Act at our Baldwin facility was approved by the court on May 27, 2005. This consent decree requires us to install, among other things, additional emission controls at our Baldwin, Vermilion and Havana plants. Thus, we expect to incur significant additional costs to comply with these requirements in the future. If we fail to comply with these requirements, we could be subject to civil or criminal liability and fines or could be forced to curtail or cease operations. In addition, we may be required to incur costs to remediate contamination from past releases of hazardous substances or wastes into the environment in connection with currently or previously owned or operated properties and any other properties at which we have generated, stored, disposed, treated or arranged for disposal of hazardous substances. Failure to comply with these statutes, rules and regulations may result in the assessment of administrative, civil and even criminal penalties. Furthermore, the failure to obtain or renew an environmental permit could prevent operation of one or more of our facilities. Existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to us or our facilities in a manner that may have a detrimental effect on our business. With the continuing trend toward stricter standards, greater regulation and more extensive permitting requirements, we expect that our capital and operating environmental expenditures will continue to be substantial and may increase in the future. We may not be able to obtain or maintain from time to time 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 and comply with them, the operation of our facilities may be interrupted or become subject to additional costs.

The emission of certain substances is subject to licensing programs, which allow the trading of licenses under certain conditions. The costs of buying any necessary licenses could vary and have a material adverse effect on our financial condition, results of operations and cash flows.

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, 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. Because 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, we are unable to assess fully the impact that these uncertainties may have on our business.

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Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.

Our generation facilities and the facilities of third parties on which they rely may be targets of terrorist activities, as well as events occurring in response to or in connection with such activities, that could result in full or partial disruption of the ability to generate, transmit or transport electricity or natural gas and/or cause environmental repercussions. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. Any such disruptions or environmental repercussions, if not covered by insurance, could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows.

In the wake of the September 11, 2001 terrorist attacks on the United States, the Coast Guard has developed a security guidance document for marine terminals and has issued a security circular that defines appropriate countermeasures for protecting them and explains how the Coast Guard plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the Coast Guard, we have specifically identified our Havana, Danskammer and Roseton facilities as marine terminals and therefore potential terrorist targets. In compliance with the Coast Guard guidance, we performed vulnerability analyses on such facilities. Future analyses of our security measures may result in additional measures and procedures, which measures or procedures have the potential for increasing our costs of doing business. Regardless of the steps taken to increase security, however, we cannot be assured that these or other of our facilities will not become the subject of a terrorist attack.

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

As of December 31, 2005, approximately 63% of the employees at Dynegy-operated facilities were subject to collective bargaining agreements with various unions that expire in 2007 and 2008. In the event that our union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we would be responsible for procuring replacement labor or we could experience reduced power generation or outages. Our ability to procure such labor is uncertain. Strikes and work stoppages or our 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.

We reported a material weakness in our internal control over financial reporting that, if not remedied, could adversely affect our internal controls.

In connection with management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, management concluded that, as of December 31, 2005, 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. Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 was audited by PricewaterhouseCoopers LLP, which expressed an unqualified opinion on management s assessment and an adverse opinion on the effectiveness of our internal control over financial reporting as of December 31, 2005.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements would not be prevented or detected. We previously reported in our 2004 Form 10-K that we did not maintain effective internal control over financial reporting as of December 31, 2004 due to the same material weakness discussed above. During 2005, actions were taken to remediate the material weakness reported in our 2004 Form 10-K. Despite these efforts, when making management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, we determined that those controls were still not operating effectively.

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This control deficiency resulted in the restatement of our 2004 and 2003 annual consolidated financial statements, as well as year-end audit adjustments to the 2005 income tax provision. Further, this control deficiency could have resulted in a misstatement of the income tax provision and related deferred tax accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

We have taken steps to remediate the material weakness, and plan to take additional steps during 2006. Although we believe we have addressed the material weakness with the remedial measures we have implemented and plan to implement, the measures we have taken to date and any future measures may not remediate the material weakness reported and we may not be able to implement and maintain effective internal control over financial reporting in the future. In addition, additional deficiencies in our internal controls may be discovered in the future. Any failure to remediate the reported material weakness or to implement new or improved controls, or difficulties encountered in their implementation, could harm our operating results, cause us to fail to meet our reporting obligations or result in material misstatements in our financial statements. Any such failure also could affect the ability of our management to certify that our internal controls are effective when it provides an assessment of our internal control over financial reporting, and could affect the results of our independent registered public accounting firm s attestation report regarding our management s assessment. Inferior internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our stock.

Risks Related to Investing in Our Common Stock

We have significant debt that could negatively impact our business.

Dynegy has and will continue to have a significant amount of debt outstanding. As of December 31, 2005, we had total consolidated debt (including lease obligations) of $5.2 billion, which consisted of the second priority senior secured notes and other debt, including other secured and unsecured facilities and certain operating leases of our subsidiaries. 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.

Although we believe that refinancing activity which we are currently considering for near term execution would reduce our total consolidated debt, we cannot assure you that any such reduction will occur. Even if such refinancing activity is successful, we will remain highly leveraged. Furthermore, we may incur additional indebtedness in the future. If new debt is added to our current debt levels and those of our subsidiaries, the related risks that we and they face could increase significantly.

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We expect that our non-investment grade status will continue to adversely affect our financial condition, results of operations and cash flows.

Our credit ratings are currently below investment grade and could be downgraded further. Our current non-investment grade ratings increase our borrowing costs, both by increasing the actual interest rates we are required to pay under any existing indebtedness and any debt in the capital markets that we are able to issue. Our credit ratings also require us to either prepay or post significant amounts of collateral in the form of cash and letters of credit to support our business. We cannot be sure that our credit ratings will improve, or that they will not decline, in the future.

Additionally, our non-investment grade status limits our ability to refinance our debt obligations and to access the capital markets. Should our ratings continue at their current levels, or should our ratings be further downgraded, we would expect these negative effects to continue and, in the case of a downgrade, become more pronounced.

The terms of our debt may severely limit our ability to plan for or respond to changes in our businesses.

The terms of our Senior Secured Credit Facility and our Second Priority Senior Secured Floating Rate Notes Due 2008, 9.875% Second Priority Senior Secured Notes Due 2010 and 10.125% Second Priority Senior Secured Notes Due 2013, or Secured Debt, restrict our ability to take specific actions in planning for and responding to changes in our business without the consent of the lenders, even if such actions may be in our best interest. Our Secured Debt also require us to meet specific financial tests to issue debt and make restricted payments, among other things. Further, the senior debt associated with the Sithe Independence indenture prohibits cash distributions by Independence to its affiliates, including Dynegy, unless certain project reserve accounts are funded to specified levels and the required debt service coverage ratio is met. Our ability to comply with the covenants in our financing agreements, as they currently exist or as they may be amended, may be affected by many events beyond our control, and our future operating results may not allow us to comply with the covenants, or in the event of a default, to remedy that default. Our failure to comply with those financial covenants or to comply with the other restrictions in our financing agreements could result in a default, requiring such financing agreements (and by reason of cross-default or cross-acceleration provisions, our other indebtedness) to become immediately due and payable. If we are unable to repay those amounts or to otherwise cure the default, the holders of the indebtedness under our Secured Debt could proceed against the collateral granted to them to secure that indebtedness. If those lenders accelerate the payment of such indebtedness, we cannot assure that we could pay or refinance that indebtedness immediately and continue to operate our business.

Our access to the capital markets may be limited.

We may require additional capital from outside sources from time to time. 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. The failure to obtain additional capital from time to time 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. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth.

We may not have adequate liquidity to post required amounts of additional collateral.

We 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 the counterparties views of our creditworthiness, as well as changes in commodity prices. If commodity prices change substantially, our liquidity could be severely strained by requirements under our commodity agreements to post additional collateral. In certain cases, our counterparties have elected to not require the posting of collateral to which they are otherwise entitled under certain agreements. However, those counterparties retain the right to request the posting of such collateral. Factors that could trigger increased demands for collateral include additional adverse changes in our industry, negative regulatory or litigation developments, adverse events affecting us, changes in our credit rating or liquidity, and changes in commodity prices for power and fuel. In addition, to the extent we do hedge against volatility in commodity prices, we may be exposed to additional collateral requirements without adequate liquidity to post required amounts of additional collateral. An increase in demands from our counterparties to post letters of credit or cash collateral may have a material adverse effect on our financial condition, results of operations and cash flows.

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, a number of securities class action lawsuits that were settled in 2005, purported class action suits with respect to alleged violations of the Employment Retirement Income Security Act 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. Three significant matters are described below:

DNE is involved in litigation or administrative proceedings regarding the State Pollutant Discharge Elimination System, or SPDES, permits for two of our facilities, Roseton and Danskammer, in New York. In April 2005, the New York State Department of Environmental Conservation, or NYSDEC, issued to DNE a draft SPDES Permit for the Roseton plant. The draft SPDES Permit contains provisions governing, among other things, the cooling water intake and the discharge of heated effluent water. In mid- 2005, three organizations filed petitions for party status seeking to impose a permit requirement that the Roseton plant install a closed cycle cooling system. We believe that Petitioners claims are without merit; however, given the high cost of installing a closed cycle cooling system, an adverse result in this proceeding could have a material adverse effect on our financial condition, results of operations and cash flows.

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Danskammer s SPDES Permit was issued for a five-year term in 1987. Prior to expiration of the permit, an application to renew the SPDES Permit was filed. In November 2002, several environmental groups filed suit in the Supreme Court of the State of New York seeking, among other things, a declaratory judgment that the Danskammer SPDES Permit had expired because of alleged deficiencies in the renewal application process. In August 2004, the Court ruled that the SPDES Permit for our Danskammer facility was void, but stayed the enforcement of the decision pending further review by the Court or by the Appellate Division. In October 2004, we filed our appeal of the Court s decision with the Appellate Division and are currently challenging the Court s ruling voiding our permit. Oral argument before the Appellate Division occurred in September 2005, and a decision is expected in the first quarter 2006. If our appeal is ultimately unsuccessful, we may be required to suspend operations at our Danskammer facility until receipt of final approval of the renewal of our Danskammer SPDES Permit. We cannot predict with any certainty the outcome of this proceeding; however, an adverse outcome, particularly a requirement that we suspend operations at our Danskammer facility for any period of time, could have a material adverse effect on our financial condition, results of operations and cash flows.

We are a party to various suits that claim damages resulting from the alleged manipulation of gas index publications and prices by us and others. In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to gas index publications. All of the complaints rely heavily on the FERC and CFTC investigations into and reports concerning index-reporting manipulation in the energy industry. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits; however, given the nature of the claims and the high costs of recent settlements of similar matters, an unfavorable result in any of these pending matters could materially adversely affect our financial condition, results of operations and cash flows.

Shortly before Enron s bankruptcy filing in the fourth quarter of 2001, we determined that we had net exposure to Enron Corp. and its affiliates, including certain liquidated damages and other amounts relating to the termination of commercial transactions among the parties, of approximately $84 million. This exposure was calculated by setting off approximately $230 million owed from Dynegy entities to Enron entities against approximately $314 million owed from Enron entities to Dynegy entities. The master netting agreement between Enron and us and the valuation of the commercial transactions covered by the agreement, which valuation is based principally on the parties assessment of market prices for such period, remain subject to dispute. In the event that Enron prevails in its position that the master netting agreement is unenforceable, our potential liability to Enron could be approximately $216 million before interest, with as much as $220 million in unsecured Dynegy claims remaining to enforce against the bankruptcy estate. If the setoff rights are modified or disallowed, either by agreement or otherwise, the amount available for our entities to set off against sums that might be due Enron entities could be reduced materially. In fact, we could be required to pay to Enron the full amount that it claims to be owed, while we would be an unsecured creditor of Enron to the extent of our claims. Given the size of the claims at issue, an adverse result could have a material adverse effect on our financial condition, results of operations and cash flows.

The interests of Chevron may conflict with your interests.

At December 31, 2005, Chevron owned approximately 35.4% of the voting power of Dynegy (assuming conversion of all of the Class B common stock and Series C preferred 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. Chevron, as a preferred stockholder, may have interests that differ from those of holders of common stock.

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Many of our senior officers have been promoted recently and have only worked together as a management team for a short period of time. In addition, a number of our senior officers have limited experience in management positions.

We have recently made several significant changes to our senior management team. In November 2005, we named a new Executive Vice President and Chief Financial Officer, who had been serving as our Senior Vice President and Treasurer since May 2004 and previously as our Senior Vice President and Controller from June 2003 to May 2004. In addition, we named a new General Counsel and Executive Vice President of Administration, who had been serving as our Senior Vice President of Human Resources since August 2004 and previously as our Group General Counsel-Corporate Finance & Securities from June 2003 to August 2004. We also named a new Executive Vice President, Strategic Planning and Corporate Business Development, who had been serving as Senior Vice President of that same group since July 2003. As a result of these recent changes in senior management, many of our officers have only worked together as a management team for a short period of time. The failure to successfully integrate the senior management team could have an adverse impact on our business operations. In addition, some of our officers and management have had limited experience in management positions. Their inexperience could negatively impact our financial condition, results of operations and cash flows.

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 physical operating properties we own, are pledged as collateral with respect to the DHI second priority senior secured notes on a second lien. Please read Note 12 Debt beginning on page F-42 for further discussion.

Our principal executive office located in Houston, Texas is held under a lease that expires in December 2007. We also lease additional offices or warehouses in the states of 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-55, 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 2005.

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PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchase 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 March 7, 2006, 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 U.S.A. Inc., which we refer to as 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, 2005 and 2004, as reported on the New York Stock Exchange Composite Tape.

Summary of Dynegy s Common Stock Price

	High	Low
2006:		
First Quarter (through March 7, 2006)	$ 5.72	$ 4.90
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
2004:		
Fourth Quarter	$ 5.86	$ 4.27
Third Quarter	4.99	3.93
Second Quarter	4.44	3.75
First Quarter	5.15	3.46

During the fiscal years ended December 31, 2005 and 2004, 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 Preferred and Common Stock beginning on page 54 for further discussion of our dividend policy and the impact of dividend restrictions contained in our financing agreements. Any decision to pay a dividend is at the discretion of the Board of Directors, but we do not expect to pay a common stock dividend in the foreseeable future.

Shareholder Agreement

In June 1999, Chevron entered into a shareholder agreement with us governing certain aspects of our relationship which amended certain of the rights and obligations previously agreed between us and Chevron at the time of Chevron s initial investment in 1996. The agreement was amended in February 2000, upon closing of the merger with Illinova, and reflected agreements negotiated between us and Chevron relating to Chevron s significant ownership interest in Dynegy. In August 2003, we entered into an amended and restated shareholder agreement with Chevron in connection with the consummation of the Series B Exchange. Please read Note 13 Related Party Transactions Series B Preferred Stock beginning on page F-46 for further discussion of the Series B Exchange. The material terms of this amended and restated shareholder agreement, which we refer to as the shareholder agreement, are described below.

The shareholder agreement 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

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securities issued pursuant to employee benefit plans. Chevron agreed to waive its preemptive rights in respect of 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.

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 disposition of all or substantially all of our NGL business while substantial agreements between Chevron and us exist (except for a contribution of such liquids business to an entity in which we have a majority direct or indirect interest);

- 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

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(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

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.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2005 as it relates to our equity compensation plans for our Class A common stock, the only class with respect to which we offer equity compensation.

Plan Category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)**	**Weighted-average exercise price of outstanding options, warrants and rights (b)**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)**
Equity compensation plans approved by security holders	6,666,070	$ 13.12	27,092,025
Equity compensation plans not approved by security holders (1)	2,995,250	$ 11.93	6,444,462
Total	9,661,320	$ 12.75	33,536,487

(1) The plans that were not approved by our security holders are as follows: Extant Plan, Dynegy 2001 Non-Executive Stock Incentive Plan and Dynegy UK Plan. Please read Note 19 Capital Stock Stock Options beginning on page F-69 for a brief description of our equity compensation plans, including these plans.

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.

As discussed in the Explanatory Note to the accompanying Consolidated Financial Statements, the historical information in the accompanying Consolidated Financial Statements has been restated. Please read the

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Explanatory Note to the accompanying Consolidated Financial Statements beginning on page F-10 for additional information about this restatement. The selected financial data that follows has been adjusted to reflect this restatement.

Dynegy s Selected Financial Data

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$ 2,313	$ 2,451	$ 2,599	$ 2,109	$ 3,635
Depreciation and amortization expense	(220)	(235)	(373)	(378)	(368)
Goodwill impairment			(311)	(814)	
Impairment and other charges	(46)	(78)	(225)	(176)	
General and administrative expenses	(468)	(330)	(315)	(297)	(385)
Operating income (loss)	(838)	(100)	(769)	(1,146)	823
Interest expense	(389)	(453)	(503)	(241)	(201)
Income tax benefit (expense)	395	172	296	337	(320)
Net income (loss) from continuing operations	(804)	(180)	(813)	(1,217)	423
Income (loss) from discontinued operations (3)	912	165	81	(1,136)	(24)
Cumulative effect of change in accounting principles	(5)		40	(234)	2
Net income (loss)	$ 103	$ (15)	$ (692)	$ (2,587)	$ 401
Net income (loss) applicable to common stockholders	81	(37)	321	(2,917)	359
Basic earnings (loss) per share from continuing operations	$ (2.13)	$ (0.53)	$ 0.53	$ (4.23)	$ 1.17
Basic net income (loss) per share	0.21	(0.10)	0.86	(7.97)	1.10
Diluted earnings (loss) per share from continuing operations	$ (2.13)	$ (0.53)	$ 0.50	$ (4.23)	$ 1.12
Diluted net income (loss) per share	0.21	(0.10)	0.78	(7.97)	1.06
Shares outstanding for basic EPS calculation	387	378	374	366	326
Shares outstanding for diluted EPS calculation	513	504	423	370	340
Cash dividends per common share	$	$	$	$ 0.15	$ 0.30
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ (30)	$ 5	$ 876	$ (25)	$ 550
Net cash provided by (used in) investing activities	1,824	262	(266)	677	(3,828)
Net cash provided by (used in) financing activities	(873)	(115)	(900)	(44)	3,450
Cash dividends or distributions to partners, net	(22)	(22)		(55)	(98)
Capital expenditures, acquisitions and investments	(315)	(314)	(338)	(981)	(4,687)

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	December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
		(restated)	**(restated)** **(in millions)**	**(restated)**	**(restated)**
Balance Sheet Data (2):					
Current assets	$ 3,706	$ 2,728	$ 3,074	$ 7,574	$ 8,944
Current liabilities	2,116	1,802	2,450	6,748	8,538
Property and equipment, net	5,323	6,130	8,178	8,458	9,269
Total assets	10,126	9,843	12,801	20,020	25,074
Long-term debt (excluding current portion)	4,228	4,332	5,893	5,454	5,016
Notes payable and current portion of long-term debt	71	34	331	861	458
Serial preferred securities of a subsidiary			11	11	46
Subordinated debentures				200	200
Series B Preferred Stock (4)				1,212	882
Series C convertible preferred stock	400	400	400		
Minority interest (5)		106	121	146	1,040
Capital leases not already included in long-term debt				15	29
Total equity	2,153	1,956	1,975	2,256	4,956

(1) The following 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:

Sithe Energies February 1, 2005;

Northern Natural February 1, 2002;

BGSL December 1, 2001 and

iaxis March 1, 2001.

(2) The Sithe Energies, Northern Natural, BGSL and iaxis 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 includes 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) The 2002 amount equals the $1.5 billion in proceeds related to the Series B Preferred Stock less the $660 million implied dividend recognized in connection with the beneficial conversion option plus $372 million in accretion of the implied dividend through December 31, 2002. The 2001 amount equals the $1.5 billion in proceeds less the $660 million implied dividend plus $42 million in accretion of the implied dividend through December 31, 2001. Please read Note 13 Related Party Transactions Series B Preferred Stock beginning on page F-46 for further discussion.

(5) The 2001 amounts include amounts relating to the Black Thunder Secured Financing. This financing involved our obligation to purchase the interest held by a third party on or before June 2005 which was recorded as an $850 million minority interest liability. We repaid the balance owed under this financing in August 2003.

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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; (2) the Northeast segment; and (3) the South segment. We also separately report the results of our CRM business, which primarily consists of Kendall, our remaining power tolling arrangement (excluding the Sithe toll which is now in GEN-NE and is an intercompany agreement) as well as our physical gas supply contracts, gas transportation contracts and remaining 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, interest and depreciation and amortization. As described below, our natural gas liquids business, which was conducted through DMSLP and its subsidiaries, was sold to Targa on October 31, 2005. Additionally, as described below, our former regulated energy delivery business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation on September 30, 2004.

Following is a brief discussion of each of our power generation and customer risk management businesses, 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 corporate-level expenses and our discontinued business segments. This Overview section concludes with a discussion of our 2005 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 energy, capacity and ancillary services. Primary factors impacting our earnings and cash flows in the 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, among other things, weather and general economic conditions. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation. We also are impacted by the relationship between prices for power and natural gas and prices for power and fuel oil, commonly referred to as the spark spread, and its impact on our cost to generate electricity. However, we believe that our significant coal-fired generating facilities partially mitigate our sensitivity to changes in the spark spread, in that our cost of coal particularly in the Midwest, is relatively stable, and position us for potential increases in earnings and cash flows in an environment where both power and gas prices increase.

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

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

- our ability to optimize our assets through in-market availability, reliable run-time and safe, efficient operations.

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Please read Item 1A. Risk Factors beginning on page 23 for additional factors that could impact our future operating results, financial condition and cash flows.

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

Power Generation Midwest Segment. Our assets in the Midwest include (1) our primarily coal-fired fleet and (2) our gas-fired fleet. Although the primary factor impacting earnings and cash flows in GEN-MW, especially the coal-fired fleet, is market power prices, the following specific factors also impact or could impact the performance of this reportable segment:

- Ongoing regulatory developments with respect to how major utilities in Illinois procure power beginning in 2007 to serve their customers will impact how we sell our generation.
- Our ability to maintain sufficient coal inventories, including 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 load.
- Potential for the State of Illinois to pursue legislation for a limitation of mercury emissions that is more stringent than federal guidelines could impose additional costs on our facilities.
- As a result of the Baldwin consent decree, cash flows in this segment will be committed to significant capital expenditures over the next few years.
- In our gas-fired fleet, earnings and cash flows are primarily weather driven. A warm summer or cold winter increases the demand for electricity, which in turn increases the 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 region include gas, fuel oil and coal-fired facilities. The following specific factors also impact or could impact the performance of this reportable segment:

- The relationship between prices for power and natural gas, commonly referred to as the spark spread, and its effect on the cost of generating electricity, impacts our gas-fired facilities in this segment.
- The relationship between prices for power and fuel oil, and its effect on our cost to generate electricity, impacts our Roseton facility.
- 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.
- A state-driven program aimed at capping carbon dioxide emissions that is more stringent than federal guidelines could impact future results.

The outcome of administrative proceedings and litigation specific to water discharge issues could materially impact operating costs at two of our New York facilities. For further discussion of these matters, please see Note 18 Regulatory Issues Roseton State Pollutant Discharge Elimination System Permit beginning on page F-65 and Note 18 Regulatory Issues Danskammer State Pollutant Discharge Elimination System Permit beginning on page F-66, respectively.

Power Generation South Segment. Assets in our South region are all gas-fired facilities. Our ERCOT facility is a base-load facility, and our other wholly-owned assets in the segment are peaking units. In December 2005, we announced our agreement to sell our remaining ownership interest in West Coast Power, which comprises our most significant equity investment in our South segment. The following specific factors also impact or could impact the performance of this reportable segment:

For the peaking units in this reportable segment, earnings and cash flows are primarily weather driven. A warm summer or cold winter increases the demand for electricity, which in turn increases the run time of our peaking plants. Natural gas market prices have remained high throughout 2005, and power prices have generally tracked high gas prices, enabling us to benefit from operation of all of our peaking facilities during the summer months.

Our ability to enter into capacity agreements for our peaker units could impact future results.

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.

Customer Risk Management

Our CRM segment is comprised largely of the Kendall power tolling arrangement (excluding the Sithe toll which is now in GEN-NE and is an intercompany agreement). In addition, our CRM segment includes physical gas supply contracts, gas transportation contracts and remaining 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 gas, power and emission trading 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. Our remaining transactions still require cash proceeds to purchase gas for our customers; however, those cash requirements are partially offset by the proceeds received from financial contracts hedging the supply. Therefore, the profit and loss impact of price movements are mitigated by these offsetting financial positions. Our remaining power trading business, exclusive of our power tolling arrangements, is expected to be substantially exited by the end of 2006. Although these transactions are accounted for on a mark-to-market basis and will continue to impose volatility in our statement of operations as prices change during the year, we currently anticipate that these transactions will be cash flow positive for 2006 on an aggregate basis. Finally, we have forward obligations to deliver SO_2 emission allowances in 2006, 2007, and 2008, and we currently own adequate allowances to satisfy the forward obligations. However, we experience volatility in our statement of operations, as the value of these obligations changes due to changes in underlying emissions prices, and while the allowances are included in inventory on our consolidated balance sheets, only downward changes in value are recognized in our statement of operations.

Other

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

interest expense, which increased beginning in 2003 as a result of our refinancing and restructuring activities and will continue to reflect our non-investment grade credit ratings;

general and administrative costs, 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 and (ii) potential funding requirements under our pension plans; and income taxes, which will be impacted by our ability to realize our significant deferred tax assets, including loss carryforwards.

In addition, dividends associated with our outstanding preferred stock will continue to affect our earnings available to our common shareholders.

Discontinued Businesses

Natural Gas Liquids. Our natural gas liquids business, which we sold to Targa Resources in October 2005, was comprised of our natural gas gathering and processing, or upstream, assets and integrated downstream assets used to fractionate, store, terminal, transport, distribute and market natural gas liquids. NGL s results are reflected in Discontinued Operations in our consolidated statements of operations.

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Regulated Energy Delivery. Our regulated energy delivery segment 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 AmerenIP.

Company Highlights

During 2005, we continued to work to restore credibility and trust in our company, in part through the restructuring and elimination of many liabilities and risks facing us. To that end, we accomplished the following throughout 2005:

February 2005 we acquired Sithe Energies. As a result of this acquisition, a significant toll obligation became an intercompany agreement.

May 2005 we entered into a comprehensive settlement resolving environmental litigation related to our Baldwin Energy Complex in Illinois.

July 2005 the U.S. District Court approved the comprehensive settlement agreement of the parties in our shareholder class action litigation.

October 2005 we completed the sale of DMSLP, which comprised substantially all of the operations of our NGL segment, to Targa Resources Inc. and two of its subsidiaries.

October 2005 we entered into a Second Amended and Restated Credit Agreement comprised of (i) a $400 million letter of credit component and (ii) a $600 million revolving credit component. On November 1, 2005, the $600 million outstanding principal balance associated with the revolver was paid in full, and on December 16, 2005, we elected to terminate the revolving credit commitment.

November 2005 we approved several changes to our executive management team.

December 2005 we completed an asset sale offer to purchase at par up to $1.75 billion aggregate principal amount of our Second Priority Senior Secured Floating Rate Notes Due 2008, 9.875% Second Priority Senior Secured Notes Due 2010 and 10.125% Second Priority Senior Secured Notes Due 2013 under the terms of the Indenture governing such notes, redeeming all of the $400,000 in aggregate principal amount outstanding that were validly tendered for redemption by the holders and not withdrawn.

December 2005 we entered into an agreement with Quachita Power LLC, a joint venture of GE Energy Financial Services and Cogentrix Energy, Inc., to terminate the Sterlington toll contract. The agreement closed on March 7, 2006.

December 2005 we announced a comprehensive restructuring plan in order to better align our corporate cost structure with our single line of business. The plan included position eliminations and process and system changes.

December 2005 we entered into two purchase and sale agreements with NRG Energy, Inc. pursuant to which we will purchase NRG s 50% indirect interest in the Rocky Road facility, and NRG will purchase our 50% indirect interest in WCP (Generation) Holdings LLC. The transactions, which are conditioned upon one another, are expected to close in early 2006.

Key Objectives. Looking forward, the following objectives will govern how we conduct our business and make key decisions:

Further reduce total debt while maintaining a flexible capital structure that provides an opportunity for growth and market recovery;

Sustain adequate liquidity to provide a solid financial foundation;

Achieve fiscally responsible growth through combinations or acquisitions of assets that are a strategic fit or can create cost synergies with existing assets; and

Provide long term return on investment to shareholders.

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In the near term, we are focused on deploying the proceeds from the sale of DMSLP in a manner that best aligns with our key objectives. We are considering executing one or more financing transactions in the near term designed to reduce existing debt or preferred stock obligations or replace certain remaining debt obligations with less restrictive obligations. Transactions to redeem outstanding debt or preferred stock may require us to pay a premium over market price. We are also considering other capital-raising activities in the near term, including potential public or private equity issuances the proceeds of which may be used to fund reductions or redemptions of debt or preferred stock obligations. Matters to be considered will include reducing cash interest expense, covenant flexibility, return on investment and maturity profile all to be balanced with maintaining adequate liquidity. We cannot assure you that we will be successful in our efforts to deploy the DMSLP sale proceeds consistent with these objectives.

We further believe that our efficient and scalable operations platform, together with our multi-fuel capabilities and regionally-focused presence, position us to benefit from opportunities that might arise in connection with any growth transactions or industry consolidation activities. To achieve these strategic objectives, we expect to continue to pursue opportunities that may develop and expand our existing facilities, achieve operating efficiencies or provide opportunistic expansion within our core markets.

However, our desire or ability to pursue any such opportunities is subject to a number of factors beyond our control. As such, we cannot guarantee that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities on our financial condition or results of operations.

Please read Item 1A. Risk Factors beginning on page 23 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, legal settlements 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, asset sale proceeds and proceeds from capital market transactions, to the extent that we engage in these activities prospectively.

Debt Obligations

During 2005, we continued our efforts to reduce our outstanding debt and extend our maturity profile, evidenced by the following transactions:

- $18 million repayment of 8.125% senior notes that matured in March 2005;

- $34 million payment related to our Independence Senior Notes due 2007;

- $597 million repayment of amount outstanding on our term loan and repayment of accrued interest associated with the former credit facility, repaid with $600 million borrowed under the revolving credit component of the Amended and Restated Credit Facility;

- $189 million repayment of generation facility borrowings on October 31, 2005; and

- $600 million repayment of amount due under the revolving credit component of the Amended and Restated Credit Facility in November 2005.

Following such repayments, our debt maturity profile as of December 31, 2005 includes $71 million in 2006, $40 million in 2007, $269 million in 2008, $57 million in 2009, $688 million in 2010 and approximately $3.2 billion thereafter. Maturities for 2006 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 and Long-term debt on our consolidated balance sheets.

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Amended and Restated Credit Facility. On October 31, 2005, we replaced our former $1.3 billion credit facility with a second amended and restated credit agreement (the Amended and Restated Credit Facility), comprised of (i) a $400 million letter of credit component maturing in October 2008 and (ii) a $600 million revolving credit component, which matured in December 2005. The Amended and Restated Credit Facility was collateralized with cash as well as other assets that were pledged under the former credit facility, excluding those assets sold in connection with the sale of DMSLP, as we were required to post cash collateral in an amount equal to 103% of outstanding letters of credit and borrowings under the Amended and Restated Credit Facility. We earned interest income on the cash on deposit in the cash collateral account.

A letter of credit fee was payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 0.50% of the undrawn amount. We also incurred additional fees for issuing letters of credit. Amounts drawn on letters of credit issued pursuant to the facility, as well as borrowings under the revolving credit component of the facility, bore interest at a base rate plus 0.50% per annum. An unused commitment fee of 0.10% was payable on the unused portion of the Amended and Restated Credit Facility.

On October 31, 2005, we borrowed $600 million under the revolving credit component of the Amended and Restated Credit Facility to repay the term loan and accrued interest associated with the former credit facility. The $600 million outstanding principal balance of the revolving credit component was paid in full on November 1, 2005 without a corresponding reduction in revolving credit commitments. On December 16, 2005, we elected to terminate the revolving credit commitment under the Amended and Restated Credit Facility.

Senior Secured Credit Facility. On March 6, 2006, we entered into a third amended and restated credit agreement (the Senior Secured Credit Facility) with Citicorp USA, Inc. and JPMorgan Chase Bank, N.A., as co-administrative agents, JP Morgan Chase Bank, N.A., as collateral agent, Citigroup Global Markets Inc. and JP Morgan Securities Inc., as joint lead arrangers, and the other financial institutions parties thereto as lenders. The Senior Secured Credit Facility replaces our former cash-collateralized Amended and Restated Credit Facility with a $400 million revolving credit facility, thereby permitting the return to DHI of $335 million plus accrued interest in cash collateral securing the former Amended and Restated Credit Facility. The Senior Secured Credit Facility is secured by substantially all of the assets of DHI, as borrower, and certain of its subsidiaries, as subsidiary guarantors, and certain of the assets of Dynegy, as parent guarantor. Letters of credit issued under the former Amended and Restated Credit Facility will be continued under the Senior Secured Credit Facility.

The revolving credit facility matures March 6, 2009. Borrowings under the revolving credit facility bear interest, at DHI s option, at either the base rate, which is calculated as the higher of Citibank s publicly announced base rate and the federal funds rate in effect from time to time plus 0.50%, or the Eurodollar rate, in each case, plus an applicable margin. The applicable margin is 1% per annum for base rate loans and 2% percent per annum for Eurodollar loans. An unused commitment fee of 0.50% is payable on the unused portion of the revolving credit facility.

The Senior Secured Credit Facility contains mandatory prepayment provisions associated with specified asset sales and dispositions (including as a result of casualty or condemnation) and the receipt of proceeds by DHI and certain of its subsidiaries of any permitted additional non-recourse indebtedness. Commencing in 2008 with respect to the fiscal year ending December 31, 2007, each year DHI will be required to apply toward the prepayment of the loans and the permanent reduction of the commitments under the revolving credit facility (or to posting cash collateral in lieu thereof), a portion of its excess cash flow as calculated under the Senior Secured Credit Facility for the prior fiscal year. This portion will be 50% initially and will fall to 25% when and if DHI s leverage ratio is less than or equal to 3.50 to 1.00.

The Senior Secured Credit Facility contains affirmative covenants and negative covenants and events of default. Subject to certain exceptions, DHI and its subsidiaries are subject to restrictions on incurring additional indebtedness, limitations on capital expenditures and limitations on dividends and other payments in respect of capital stock. The Senior Secured Credit Facility also contains certain financial covenants, including a minimum

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cash equivalents covenant that requires DHI and certain of its subsidiaries to maintain at all times cash equivalents in an aggregate principal amount of no less than $1 billion and a leverage ratio of secured debt to adjusted EBITDA of no greater than 9.0:1 through December 31, 2006, no greater than 7.5:1 during 2007, and no greater than 7.0:1 during 2008 and thereafter.

We have incurred significant debt service obligations in the course of extending our debt maturities. We also are subject to covenants in the related transaction agreements that are substantially more restrictive than those typically found in financing agreements of borrowers with investment grade credit ratings, including covenants limiting our ability to incur additional debt, distribute funds within our corporate structure and sell certain assets. We are currently in compliance with these restrictive covenants, but our future financial condition and results of operations could be materially adversely affected by our ability to comply with these restrictive covenants in the future.

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, 2005 and 2004:

	December 31, 2005	December 31, 2004
	(in millions)	
First Secured Obligations		
Dynegy Holdings Inc.	$ 785	$ 1,551
Sithe Energies (1)	885	
Total First Secured Obligations	1,670	1,551
Second Secured Obligations	1,750	1,750
Unsecured Obligations	1,786	1,831
Subtotal	5,206	5,132
Preferred Obligations	400	400
Total Obligations	$ 5,606	$ 5,532
Less: DNE Lease Financing (2)	(785)	(771)
Less: Preferred Obligations	(400)	(400)
Other (3)	(122)	5
Total Notes Payable and Long-term Debt (4)	$ 4,299	$ 4,366

(1) Please read Note 3 Acquisition Sithe Energies beginning on page F-21 for further discussion.
(2) Represents present value of future lease payments discounted at 10%.
(3) Consists of net discounts on debt of $122 million and net premiums on debt of $5 million at December 31, 2005 and 2004, respectively.
(4) Does not include letters of credit.

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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 March 7, 2006, December 31, 2005 and December 31, 2004:

	March 7, 2006	December 31, 2005	December 31, 2004
		(in millions)	
By Business:			
Generation business	$ 185	$ 280	$ 192
Customer risk management business	76	91	94
Natural gas liquids business			167
Other	8	10	17
Total	$ 269	$ 381	$ 470
By Type:			
Cash (1)	$ 81	$ 122	$ 376
Letters of Credit	188	259	94
Total	$ 269	$ 381	$ 470

(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 decrease in collateral postings from December 31, 2005 to March 7, 2006 is primarily due to a return of collateral postings in our generation business. This decrease is primarily a result of decreases in commodity prices since the end of 2005. The decrease in collateral postings from December 31, 2004 to December 31, 2005 is primarily due to a return of collateral postings related to the natural gas liquids business as a result of the sale of DMSLP, offset by an $88 million increase in postings in our generation business. This increase in our generation business is primarily the result of increases in commodity prices and an increase in the volume of fuel purchased as we no longer purchase gas from DMSLP. In addition, approximately $40 million of the increase is due to cash collateral posted by Dynegy on behalf of West Coast Power. A significant majority of this amount is offset by cash collateral received from West Coast Power. This amount will be eliminated upon the sale of our 50% interest in West Coast Power, currently anticipated to occur in early 2006. The collateral posted in support of our customer risk management business on December 31, 2005 was $3 million less than the amount posted on December 31, 2004. During 2005 the collateral posted on behalf of our customer risk management business decreased primarily due to the expiration of the Gregory tolling agreement and the rolloff of NYMEX positions, which was offset by an increase in volumes of fuel purchased. Finally, Other collateral postings decreased primarily as a result of a refund of collateral related to Illinois Power subsequent to its sale in September 2004.

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. Considering our credit ratings, the sale of DMSLP and current commodity price estimates, specifically as prices relate to fuel purchases and power hedging activity, we estimate that collateral requirements will be approximately $300 million at year-end 2006. We believe that we have sufficient capital resources to satisfy counterparties collateral demands, including those for which no collateral is currently posted, for at least the next twelve months. Over the longer term, we expect to achieve incremental collateral reductions associated with the completion of our exit from the customer risk management business.

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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.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2005. Cash obligations reflected are not discounted and do not include related interest, accretion or dividends.

	Payments Due by Period						
	Total	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**
Long-Term Debt (including Current Portion)	$ 4,299	$ 71	$ 40	$ 269	$ 57	$ 688	$ 3,174
Redeemable Preferred Securities	400						400
Operating Leases	1,546	97	144	162	160	114	869
Capacity Payments	1,509	136	138	140	142	145	808
Conditional Purchase Obligations	123	12	11	13	11	12	64
Pension Funding Obligations	70	17	12	18	14	9	
Other Obligations	86	12	16	16	16	17	9
Total Contractual Obligations	$ 8,033	$ 345	$ 361	$ 618	$ 400	$ 985	$ 5,324

Long-Term Debt (including Current Portion). Total amounts of Long-Term Debt (including Current Portion) are included in the December 31, 2005 Consolidated Balance Sheet. For additional explanation, please read Note 12 Debt beginning on page F-42.

Additionally, we have entered into various joint ventures principally to share risk or optimize existing commercial relationships. These joint ventures maintain independent capital structures and, where necessary, have financed their operations on a non-recourse basis to us. Please read Note 10 Unconsolidated Investments beginning on page F-35 for further discussion of these joint ventures.

Redeemable Preferred Securities. Total amounts of Redeemable Preferred Securities are included in the December 31, 2005 Consolidated Balance Sheet. For additional explanation, please read Note 15 Redeemable Preferred Securities beginning on page F-53.

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 52. 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 $13 million each year for the years 2006 through 2008, and approximately $66 million through lease expiration. The charter party rates payable under the two charter party agreements float in accordance with market based rates for similar shipping services. The $13 million and $66 million numbers 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 are currently in negotiations with the owners of the VLGCs and their lenders to obtain a novation and release of our operating

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subsidiary from the two charter party agreements and partial releases of our parent guarantees. Until such time as the novations and partial releases are granted, 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.

Capacity Payments. Capacity payments include future payments aggregating $1.2 billion under the Sterlington and Kendall power tolling arrangements, as further described in Item 1. Business Segment Discussion Customer Risk Management Segment beginning on page 14. We terminated the Sterlington long-term wholesale power tolling contract with Quachita Power LLC effective March 7, 2006. Accordingly, the capacity payments of approximately $751 million associated with this agreement will be eliminated. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sterlington Contract Termination beginning on page F-23 for further discussion.

In November 2004, we entered into a back-to-back power purchase agreement under which a subsidiary of Constellation Energy receives our rights to capacity and energy under the Kendall tolling arrangement for a four year term expiring effectively in November 2008. Although we are still obligated under the Kendall toll, as of December 31, 2005, we will receive approximately $122 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 beginning on page F-25 below for further discussion.

In addition, capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $302 million.

Conditional Purchase Obligations. Amounts relate to our co-sourcing agreement with Accenture LLP for employee and infrastructure outsourcing. The co-sourcing agreement previously contained a contract termination fee, which ranges from $5 million if terminated in the first quarter of 2006, declining to $2 million if terminated during 2013, and allows for renegotiation, or partial termination , if our purchasing levels fall below minimum levels. As of December 31, 2005, the termination fee was $5 million. In the fourth quarter, as a result of our sale of DMSLP to Targa, we determined our purchasing levels would no longer meet the minimum levels set forth in the co-sourcing agreement and initiated negotiations with Accenture to partially terminate, or amend, the co-sourcing agreement. During the fourth quarter 2005, we recorded a $3 million pre-tax charge to reflect our best estimate of the cost associated with the partial termination of the co-sourcing agreement. The charge is reflected as a reduction in the gain on sale of DMSLP included in income from discontinued operations on our consolidated statements of operations. We recently amended this agreement to reduce our annual rate and to extend the term through October 2015. We agreed to pay $3 million to Accenture in early 2006 in connection with the execution of the amended 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 2006 ($17 million), 2007 ($12 million) and 2008 ($18 million). Although we expect to incur significant funding obligations subsequent to 2008, 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 $66 million as of December 31, 2005. 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 $20 million as of December 31, 2005.

Please read Note 3 Acquisition Sithe Energies beginning on page F-21 for more information on this agreement.

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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 $17 million over the ten year term of the lease.

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2005 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)	$ 259	$ 254	$ 5	$	$
Surety Bonds (2)(3)	34	34			
Guarantees (4)	4		4		
Total Financial Commitments	$ 297	$ 288	$ 9	$	$

(1) Amounts include outstanding letters of credit.
(2) Surety bonds are generally on a rolling 12-month basis.
(3) $31 million of the surety bonds were supported by collateral.
(4) 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 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. 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. For further information, please see Note 17 Commitments and Contingencies Other Commitments and Contingencies Guarantees and Indemnifications.

Off-Balance Sheet Arrangements

DNE Leveraged Lease. We established our presence in the Northeast region by acquiring 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 financing for our acquisition. 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 these 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., who 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.

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As of December 31, 2005, future lease payments are $60 million for 2006, $108 million for 2007, $144 million for 2008, $141 million for 2009, $95 million for 2010 and $112 million for 2011, with $712 million in the aggregate due from 2012 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, 2005, the present value (discounted at 10%) of future lease payments was $785 million.

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

	2005	2004	2003
		(in millions)	
Lease Expense	$ 50	$ 50	$ 50
Lease Payments (Cash Flows)	$ 60	$ 60	$ 60

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, 2005, 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-39.

Capital Expenditures

We continue to tightly manage costs and capital expenditures. We had approximately $195 million in capital expenditures during 2005. Our 2005 capital spending by reportable segment was as follows (in millions):

GEN-MW	$ 113
GEN-NE	21
GEN-SO	9
NGL	45
Other	7

Total	$ 195

Capital spending in our GEN-MW segment primarily consisted of maintenance capital projects, as well as approximately $33 million spent on development capital. Development capital spending primarily related to the conversion of our Havana and Vermilion facilities to PRB coal. Capital spending in our GEN-NE and GEN-SO segments primarily consisted of maintenance and environmental projects. Capital spending in our NGL segment primarily related to maintenance capital projects and wellconnects, as well as approximately $11 million in development capital.

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We expect capital expenditures for 2006 to approximate $189 million. 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. Estimated funds budgeted for the aforementioned items by reportable segment in 2006 are as follows (in millions):

GEN-MW	$ 112
GEN-NE	47
GEN-SO	25
Other	5
Total	$ 189

Our capital expenditures in 2006 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-42 for further discussion of these limitations. Our long term capital expenditures in the GEN-MW segment will also be significantly impacted by the Baldwin 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 $611 million through 2013.

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-55, which is incorporated herein by reference, for a discussion of our commitments and contingencies.

Dividends on Preferred and 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. We do not foresee a declaration of dividends on our common stock in the near term, particularly given our financial condition and the dividend restrictions contained in our financing agreements. Specifically, we have agreed not to pay any dividends on our common stock under the terms of the Senior Secured Credit Facility. We have, however, continued to make the required dividend payments on our outstanding trust preferred securities.

The Series B Preferred Stock issued to Chevron in November 2001 had no dividend requirement. Because of Chevron s discounted conversion option, however, we accreted an implied preferred stock dividend over the redemption period, as required by GAAP. Please read Note 13 Related Party Transactions Series B Preferred Stock beginning on page F-46 for further discussion of this non-cash implied dividend and the Series B Exchange. In conjunction with the Series B Exchange, we recognized a gain of approximately $1.2 billion as a preferred stock dividend during 2003.

We accrue dividends on our Series C preferred stock at a rate of 5.5% per annum. We accrued and made dividend payments on the Series C preferred stock during the year ended December 31, 2005 totaling approximately $22 million. Dividends are payable on the Series C preferred stock in February and August of each year, but we may defer payments for up to 10 consecutive semi-annual periods. Please read Note 15 Redeemable Preferred Securities beginning on page F-53 for further discussion.

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We declared and paid dividends of $11 million in February 2006. Unless we have sufficient liquidity at the parent level, we may be required to defer payment of dividends on the Series C preferred stock beginning in August 2006.

Please read Company Highlights Key Objectives beginning on page 45 for discussion of potential near-term liability management activities, which may include reduction or redemption of debt or preferred stock obligations.

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 March 7, 2006, December 31, 2005 and December 31, 2004:

	March 7, 2006	December 31, 2005	December 31, 2004
		(in millions)	
Total revolver capacity	$ 400(4)	$	$ 700
Total additional letter of credit capacity		325(1)	
Outstanding letters of credit under credit facility	(188)	(254)	(94)
Unused credit facility capacity	212	71	606
Cash	1,528(2)	1,549(2)	628(2)(3)
Total available liquidity	$ 1,740	$ 1,620	$ 1,234

(1) On October 31, 2005, we amended and restated the credit facility to consist of (i) a $400 million letter of credit component and (ii) a $600 million revolving credit component. On December 16, 2005, we elected to terminate the revolving credit commitment. Please read Note 12 Debt Amended and Restated Credit Facility beginning on page F-43 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 March 7, 2006, December 31, 2005 and December 31, 2004 amounts include approximately $3 million, $3 million and $47 million, respectively, of cash that remains in the U.K. only for the year ended December 31, 2005 and both Canada and the U.K. for the year ended December 31, 2004 that is associated primarily with contingent liabilities relating to our former Canadian and U.K. marketing and trading operations.

(3) The December 31, 2004 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-27.

(4) On March 6, 2006, we amended and restated the credit facility. Please see Note 23 Subsequent Events beginning on page F-81.

Cash Flows from Operations. We had operating cash outflows of $30 million for the year ended December 31, 2005. This consisted of $472 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, partially offset by decreases in working capital due to increased accounts receivable. Additionally, this included $288 million in operating cash flows from our discontinued natural gas liquids business. The cash flows from these businesses were offset by $790 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.

For 2006, our estimate of operating cash outflows totals $210 to $100 million. This estimate, which is based on quoted forward commodity prices curves as of February 7, 2006 and is subject to change based on a number

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of factors, many of which are beyond our control, reflects $530 to $630 million in estimated operating cash flows from our generation business, offset by estimated cash outflows of $380 million from our customer risk management business and $360 to $350 million in corporate-level expenses, including $410 million of interest.

On October 31, 2005, cash interest expense associated with the term loan and the generation facility debt were eliminated, as these instruments were repaid in full. However, until the remaining cash proceeds from the sale of DMSLP are re-invested or utilized in a liability management program, as more fully described in Note 12 Debt DMSLP, the interest income from the cash proceeds will be more than offset by the reduction in operating cash flows from the NGL business and may continue to be more than offset depending on the ultimate disposition of the cash.

Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to manage tightly our operating costs, including costs for fuel and maintenance. Our ability to achieve fuel-related and other 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 2006 Outlook for further discussion.

Cash on Hand. At March 7, 2006 and December 31, 2005, we had cash on hand of $1,528 million and $1,549 million, respectively, as compared to $628 million at the end of 2004. This increase in cash on hand at March 7, 2006 and December 31, 2005 as compared to the end of 2004 is primarily attributable to the sale of DMSLP and is offset by cash used for debt repayments, in the Sithe acquisition, shareholder litigation settlement and capital expenditures.

Revolver Capacity. On October 31, 2005, we entered into an Amended and Restated Credit Agreement comprised of (1) a $400 million letter of credit component and (2) a $600 million revolving credit component. On December 16, 2005, we elected to terminate the revolving credit commitment. We were required to post cash collateral in an amount equal to 103% of outstanding letters of credit. Therefore, our capacity to issue letters under the Amended and Restated Credit Facility was dependent upon and limited by the amount of cash collateral on deposit. On March 6, 2006, we entered into the Senior Secured Credit Facility replacing the former Amended and Restated Credit Facility with a $400 million revolving credit facility, thereby providing the return to DHI of $335 million plus accrued interest in cash collateral securing the former Amended and Restated Credit Facility. As of March 7, 2006, $188 million in letters of credit are outstanding but undrawn, and we have no revolving loan amounts drawn under the Senior Secured Credit Facility. Please read Note 12 Debt Amended and Restated Credit Facility beginning on page F-43 for further discussion of our amended credit facility.

External Liquidity Sources

Over the last twelve months, our primary external liquidity source has been proceeds from asset sales. Looking forward, we expect our primary external liquidity sources to be proceeds from asset sales and other types of capital-raising transactions, including public or private equity issuances.

Asset Sale Proceeds. As further discussed in Note 4 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids beginning on page F-27, we sold DMSLP to Targa Resources Inc. on October 31, 2005. The terms of our former $1.3 billion credit facility and the SPN indenture and security agreements govern the use of the proceeds from this sale.

Pursuant to the SPN Indenture, in December 2005, we completed an asset sale offer to purchase at par up to $1.75 billion aggregate principal amount of our SPNs from the holders thereof at a price equal to 100% of the principal amount plus accrued and unpaid interest. We accepted for purchase and redeemed all of the $400,000 in aggregate principal amount of the notes that were validly tendered and not withdrawn. The funds available for this offer to purchase represented net cash proceeds from the sale of DMSLP. Under the terms of the SPN Indenture, Excess Proceeds from the sale of DMSLP were approximately $2.4 billion. After giving effect to the purchase of SPNs pursuant to the asset sale offer, the remaining Excess Proceeds may be used for any purpose not otherwise prohibited by the SPN Indenture.

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Capital-Raising Transactions. As part of our ongoing efforts to develop a capital structure that is more closely aligned with the cash-generating potential of our asset-based business, which is subject to cyclical changes in commodity prices, we are continuing to explore additional capital-raising transactions both in the near- and long-term. 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.

These transactions may include capital markets transactions. Our ability to issue public securities is enhanced by our effective shelf registration statement, under which we have approximately $430 million in remaining availability. This availability was not reduced by the issuance on August 12, 2005 of 17,578,781 shares of Dynegy Class A common stock pursuant to the settlement of the shareholder class action litigation, as such issuance was exempt from registration under the Securities Act of 1933. 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 credit facility. Please read Note 12 Debt Amended and Restated Credit Facility beginning on page F-43 for further discussion.

Conclusion

During 2005, we acquired Sithe Energies, which resulted in a toll obligation becoming an intercompany agreement. Mid-year, we entered into agreements to settle our Baldwin environmental litigation and our shareholder class action litigation. We completed the sale of DMSLP and aligned our corporate cost structure with our single line of business. Further, we replaced our former credit facility with an Amended and Restated Credit Facility comprised of a $400 million letter of credit component, scheduled to mature in October 2008, and a $600 million revolving credit component, which we paid in full in November and elected to terminate on December 16, 2005. In the fourth quarter, we completed an asset sale offer to purchase at par up to $1.75 billion aggregate principal amount of our SPNs under the terms of the indenture governing such notes as well as announced a new executive management team. We ended the year by entering into separate agreements (i) to terminate the Sterlington toll contract in order to eliminate significant future capacity obligation payments, and (ii) to exchange our ownership interest in West Coast Power for NRG s ownership interest in Rocky Road.

We have established key objectives that will govern how we conduct our business and make decisions. Thus, looking forward, we are focused on executing strategies to deploy the proceeds from the sale of DMSLP in a manner that best aligns us with our key objectives. We are considering executing one or more financing transactions in the near-term designed to reduce existing debt or preferred stock obligations or replace certain remaining debt obligations with less restrictive obligations. We further believe that our efficient and scalable operations platform, together with our multi-fuel capabilities and regionally-focused presence, position us to benefit from opportunities that might arise in connection with any growth transactions or industry consolidation activities.

Over the longer term and through the anticipated recovery of the U.S. power markets, we expect to maintain sufficient liquidity to satisfy our debt and commercial obligations and provide collateral support through operating cash flows, cash on hand or capacity under the revolving component of our Senior Secured Credit Facility. Further, over the last twelve months, our primary external liquidity source has been proceeds from asset sales. Looking forward, we expect our primary external liquidity sources to be proceeds from asset sales and other types of capital-raising transactions, including potential equity issuances.

Our desire or ability to pursue any of the opportunities mentioned above is subject to a number of factors beyond our control. As such, we cannot guarantee that any such strategic direction(s) will be available to us, nor can we predict with any degree of certainty the impact of any such strategic direction(s) on our financial condition, results of operations or cash flows. Please read Item 1A. Risk Factors beginning on page 23 for additional factors that could impact our future operating results and financial condition.

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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 2005, 2004 and 2003. At the end of this section, we have included our business outlook for each segment.

As reflected in this report, we have changed our reportable segments. Prior to this report, we reported results for the following segments: GEN, NGL, REG and CRM. Other reported results included corporate overhead and our discontinued business. Following the sale of Illinois Power in September 2004 and DMSLP in October 2005, our current business operations are focused primarily on the power generation sector of the energy industry. Therefore, beginning in the fourth quarter 2005, 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 our two remaining power tolling arrangements (excluding the Sithe toll which is now in GEN-NE and is an intercompany agreement) as well as our physical gas supply contracts, gas transportation contracts and remaining 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, interest and depreciation and amortization. As described below, substantially all of our natural gas liquids 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 regulated energy delivery 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.

In our year-end 2005 earnings news release furnished with our Form 8-K filed on March 8, 2006, we reported loss from continuing operations of $(803) million and net income applicable to common shareholders of $88 million for the year ended December 31, 2005. The difference between those amounts and the amounts reported herein resulted from an error related to the income tax benefit from continuing operations and the income tax expense from discontinued operations that was identified subsequent to the furnishing of our year-end 2005 earnings news release. As a result, the amounts reported herein reflect a $1 million decrease to the income tax benefit from continuing operations and a $6 million increase to the income tax expense from discontinued operations. Although diluted earnings per share from continuing operations was not impacted by this error, diluted earnings per share from discontinued operations was reduced from $2.37 to $2.35.

Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for 2005, 2004 and 2003, respectively.

Year Ended December 31, 2005

	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	REG	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							912
Cumulative effect of change in accounting principle, net of taxes							(5)
Net income							$ 103

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Year Ended December 31, 2004

	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	REG	Other and Eliminations	Total
				(in millions)			
Operating income (loss)	$ 194	$ 21	$ (52)	$ (118)	$ 139	$ (284)	$ (100)
Earnings from unconsolidated investments	80		112				192
Other items, net			1	(3)	3	8	9
Interest expense							(453)
Loss from continuing operations before taxes							(352)
Income tax benefit							172
Loss from continuing operations							(180)
Income from discontinued operations, net of taxes							165
Net loss							$ (15)

Year Ended December 31, 2003

	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	REG	Other and Eliminations	Total
				(in millions)			
Operating income (loss)	$ 196	$ 46	$ (48)	$ (385)	$ (327)	$ (251)	$ (769)
Earnings (losses) from unconsolidated investments	15		113	(2)			126
Other items, net			4	31		2	37
Interest expense							(503)
Loss from continuing operations before taxes							(1,109)
Income tax benefit							296
Loss from continuing operations							(813)
Income from discontinued operations, net of taxes							81
Cumulative effect of change in accounting principle, net of taxes							40
Net loss							$ (692)

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The following table provides summary segmented operating statistics for 2005, 2004 and 2003, respectively:

	Year Ended December 31,		
	2005	**2004**	**2003**
GEN-MW			
Million Megawatt Hours Generated Gross and Net	21.9	22.6	23.7
Average On-Peak Market Power Prices ($/MWh):			
Cinergy	$ 64	$ 43	$ 37
Commonwealth Edison (NI Hub)	$ 62	$ 42	$ 37
GEN-NE			
Million Megawatt Hours Generated Gross and Net	8.3	6.0	5.6
Average On-Peak Market Power Prices ($/MWh):			
New York Zone G	$ 92	$ 62	$ 61
New York Zone A	$ 76	$ 53	$ 51
GEN-SO			
Million Megawatt Hours Generated Gross	6.6	8.5	9.8
Million Megawatt Hours Generated Net	5.3	6.7	7.9
Average On-Peak Market Power Prices ($/MWh):			
Southern	$ 71	$ 49	$ 41
ERCOT	$ 80	$ 51	$ 45
SP-15	$ 73	$ 55	$ 52
Average natural gas price Henry Hub ($/MMBtu) (1)	$ 8.80	$ 5.85	$ 5.28
Natural Gas Liquids (5)			
Gross NGL production (MBbls/d):			
Field plants	56.6	57.3	59.6
Straddle plants	23.7	26.6	25.6
Total gross NGL production	80.3	83.9	85.2
Natural gas (residue) sales (Bbtu/d)	185.0	182.8	174.4
Natural gas inlet volumes (MMCFD):			
Field plants	518.5	535.6	591.0
Straddle plants	1,030.2	990.0	1,103.1
Total natural gas inlet volumes	1,548.7	1,525.6	1,694.1
Fractionation volumes (MBbls/d)	173.8	202.5	185.3
Natural gas liquids sold (MBbls/d)	257.7	282.5	311.7
Average commodity prices:			
Crude oil WTI ($/Bbl)	$ 54.75	$ 41.43	$ 31.01
Natural gas Henry Hub ($/MMbtu) (2)	$ 7.87	$ 6.13	$ 5.38
Natural gas liquids ($/Gal)	$ 0.87	$ 0.71	$ 0.55
Fractionation spread ($/MMBtu) daily	$ 1.91	$ 2.18	$ 0.79
Regulated Energy Delivery (6)			
Electric sales in KWh (millions)			
Residential		4,182	5,309
Commercial		3,389	4,413
Industrial		3,859	6,123
Transportation of customer-owned electricity		2,407	2,382
Other		287	374

Total electric sales		14,124	18,601
Gas sales in Therms (millions)			
Residential		214	337
Commercial		85	145
Industrial		40	70
Transportation of customer-owned gas		171	226
Total gas delivered		510	778
Cooling degree days Actual (3)		932	980
Cooling degree days 10-year rolling average		1,236	1,214
Heating degree days Actual (4)		3,145	5,256
Heating degree days 10-year rolling average		3,190	4,930

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(1) Calculated as the average of the daily gas prices for the period.
(2) Calculated as the average of the first of the month prices for the period.
(3) A Cooling Degree Day (CDD) represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in our region. The CDDs for a period of time are computed by adding the CDDs for each day during the period.
(4) A Heating Degree Day (HDD) represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in our region. The HDDs for a period of time are computed by adding the HDDs for each day during the period.
(5) Operating statistics for NGL for the year ended December 31, 2005 only include statistics through October 31, 2005, the date of the sale of DMSLP to Targa.
(6) Operating statistics for REG for the year ended December 31, 2004 only include statistics through September 30, 2004, the date of the sale of Illinois Power to Ameren.

The following tables summarize significant items on a pre-tax basis, with the exception of the tax items, affecting net income (loss) for the periods presented.

	Year Ended December 31, 2005							
	Power Generation							
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	REG	Other	Total
	(in millions)							
Discontinued operations (1)	$	$	$	$ 6	$ 1,250	$	$	$ 1,256
Sterlington toll settlement				(364)				(364)
Legal and settlement charges				(38)			(249)	(287)
Independence toll settlement charge				(169)				(169)
Asset impairment	(29)							(29)
Impairment of generation investments			(27)					(27)
Restructuring costs							(11)	(11)
Taxes							99	99
Total	$ (29)	$	$ (27)	$ (565)	$ 1,250	$	$ (161)	$ 468

(1) Discontinued operations for NGL includes gain on sale of DMSLP of $1,087 million.

	Year Ended December 31, 2004							
	Power Generation							
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	REG	Other	Total
	(in millions)							
Discontinued operations (1)	$	$	$	$ 19	$ 254	$	$ 3	$ 276
Kendall toll restructuring				(115)				(115)
Legal and settlement charges	(9)		2	(13)		(1)	(92)	(113)
Impairment of West Coast Power			(85)					(85)
Loss on sale of Illinois Power						(58)		(58)
Impairment of Illinois Power						(54)		(54)
Acceleration of financing costs							(14)	(14)

Gas transportation contracts				88				88
Gain on sale of Joppa	75							75
Taxes							24	24
Gain on sale of Oyster Creek			15					15
Total	$ 66	$	$ (68)	$ (21)	$ 254	$ (113)	$ (79)	$ 39

(1) Discontinued operations for NGL includes pre-tax gains on sales of Indian Basin, Hackberry LNG and Sherman totaling $36 million, $17 million and $16 million, respectively.

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	Year Ended December 31, 2003							
	Power Generation							
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	REG	Other	Total
	(in millions)							
Illinois Power goodwill impairment	$	$	$	$	$	$ (311)	$	$ (311)
Illinois Power asset impairment						(218)		(218)
Southern Power tolling settlement				(133)				(133)
Sithe power tolling contract				(121)				(121)
Legal charges							(50)	(50)
Batesville tolling settlement				(34)				(34)
Kroger settlement				(30)				(30)
Impairment of generation investments	$ (5)	$	(21)					(26)
Acceleration of financing costs							(24)	(24)
West Coast Power goodwill impairment			(20)					(20)
Discontinued operations (1)				(30)	148	(3)	7	122
Taxes			(1)				34	33
Gain on sale of Hackberry LNG (1)				2				2
Cumulative effect of change in accounting principles	45	11	(32)	43		(3)		64
Total	$ 40	$ 11	$ (74)	$ (303)	$ 148	$ (535)	$ (33)	$ (746)

(1) Discontinued operations for NGL includes pre-tax gains on the sale of Hackberry LNG totaling $25 million and a $12 million impairment of an equity investment.

Year Ended 2005 Compared to Year Ended 2004

Operating Loss

Operating loss was $838 million for the year ended December 31, 2005, compared to $100 million for the year ended December 31, 2004.

Power Generation Midwest Segment. Operating income for GEN-MW was $194 million for the years ended December 31, 2005 and 2004.

Results from our coal-fired generating units increased from $392 million for the year ended December 31, 2004 to $415 million for 2005. Average on-peak prices in the NI Hub/ComEd pricing region increased from $42 per MWh in 2004 to $62 per MWh for 2005. Additionally, volumes were up 3%, from 20.7 million MWh for 2004 to 21.3 million MWh. Despite the increases in output and price, results from our coal-fired generating units were negatively impacted by the AmerenIP contract, preventing us from recognizing the full benefit of the increase in market prices. Volumes sold pursuant to this contract with IP increased 25% in 2005 compared to 2004, resulting in a reduced supply of power available for sale at prevailing market prices in 2005. During certain peak periods, Ameren took higher volumes than we expected, resulting in a need to purchase power at market prices in order to satisfy our obligations. Please read Item 1. Business Segment Discussion Power

Generation Midwest Segment beginning on page 7 for a discussion of the contractual terms of these agreements. Volumes, excluding those sold under the AmerenIP contract, decreased by 1.7 million MWh from 2004 to 2005. Additionally, GEN-MW s results for 2005 include $23 million of net mark-to-market income. As a result of increased power prices and overall power price volatility, we recognized $9 million of mark-to-market gains during 2005 associated with options sold during the period, and $8 million of mark-to-market gains associated with other financial transactions. Additionally, as of December 31, 2005, we recorded $5 million of income related to FTRs that were not designated as cash flow hedges. For the year ended December 31, 2004, our results included $16 million of mark-to-market losses, primarily related to options and other transactions that economically hedged our generation assets, and were not accounted for as cash flow hedges.

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Results for our gas-fired peaking facilities in GEN-MW were improved by $11 million, from a loss of $4 million for 2004 to earnings of $7 million for 2005. This improvement was a result of favorable power pricing, caused primarily by warm weather and generally higher fuel prices. These factors made it economical to produce substantially more power than our gas-fired facilities produced in 2004. However, our 2005 results also include a lower of cost or market charge of $5 million related to the write-down of spare parts inventory.

General and administrative expense for GEN-MW decreased from $38 million in 2004 to $33 million in 2005 largely due to expenses associated with the Baldwin consent decree in 2004. Depreciation expense increased slightly, from $156 million in 2004 to $157 million in 2005. Improved 2005 results at both our coal and gas-fired facilities were offset by a $29 million charge associated with the impairment of a gas turbine not currently in use, as well as a $7 million charge associated with the write-off of an environmental project.

Power Generation Northeast Segment. Operating income for GEN-NE was $29 million for the year ended December 31, 2005, compared to $21 million for the year ended December 31, 2004.

Results from our Roseton, Danskammer and Independence facilities were $71 million for 2005, compared with $44 million in 2004. Beginning in February 2005, GEN-NE s results include earnings from the Independence facility. See Note 3 Acquisition Sithe Energies beginning on page F-21 for further discussion of the acquisition of Independence. The addition of Independence and increased power prices were the primary driver of earnings in 2005. Average on-peak market prices increased from $62 per MWh in 2004 to $92 per MWh in 2005. Compressed spark spreads for part of the year resulted in lower production at our Roseton facility, where volumes fell by 0.5 million MWh from 2004 to 2005. However, during the times Roseton was running, spark spreads were higher than the previous year. Generated volumes at our Danskammer facility rose by 0.4 million MWh from 2004 to 2005. The benefit of increased spark spreads was partly offset by operating expense, which increased from $120 million in 2004 to $139 million in 2005, primarily as a result of the timing of maintenance projects, as well as an increase in labor costs. GEN-NE s results included $12 million of mark-to-market losses and $17 million of mark-to-market gains in 2005 and 2004 respectively, related to financial transactions not designated as cash flow hedges.

General and administrative expense in GEN-NE increased from $13 million in 2004 to $22 million in 2005, primarily as a result of the addition of our Independence facility. Depreciation expense for GEN-NE increased from $10 million to $21 million, also as the result of the addition of the Independence facility.

Power Generation South Segment. Operating loss for GEN-SO was $21 million for the year ended December 31, 2005, compared to a loss of $52 million for the year ended December 31, 2004.

Results from our ERCOT facility improved by $18 million, from a loss of $12 million for 2004 to income of $6 million for 2005. Power prices increased by 57% from 2004 to 2005, and we were also able to provide additional ancillary services to the market. Results from our peaker assets in the Southeast increased, from a loss of $5 million in 2004 to earnings of $4 million in 2005, as a result of improved spark spreads in the region.

Included in the 2004 results discussed above are $8 million of mark-to-market losses, $3 million of which relates to hedge ineffectiveness in the ERCOT region, and $5 million of which relates to financial transactions not designated as cash flow hedges.

General and administrative expense was $11 million in both 2004 and 2005. Depreciation expense decreased slightly, from $25 million in 2004 to $23 million for 2005.

CRM. Operating loss for the CRM segment was $647 million for 2005, compared to operating loss of $118 million in 2004.

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Results for 2005 were impacted by the following items:

- $364 million charge associated with the agreement to terminate our Sterlington tolling arrangement.
- $169 million charge associated with the Sithe Energies acquisition. Prior to the acquisition, Independence held a power tolling contract and a gas supply agreement with our CRM segment. Upon completion of the purchase, these contracts became intercompany agreements under our GEN-NE segment, and were effectively eliminated on a consolidated basis, resulting in the $169 million charge upon completion of the acquisition.
- $74 million net losses related to our legacy power positions, primarily fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold.
- $26 million net mark-to-market loss from our legacy gas and emissions positions.
- $38 million charge related to increased legal reserves. The increased legal reserves resulted from additional activities during the year that affected management s assessment of the probable and estimable loss associated with the applicable proceedings.

These losses were partly offset by a $21 million gain related to the termination of a contract to sell emissions allowances.

Results for 2004 were impacted by the following items:

- $88 million gain associated with the exit of four natural gas transportation agreements in support of our third party marketing business; and
- $115 million charge associated with our entry into a back-to-back power purchase agreement with a subsidiary of Constellation Energy in November 2004 to mitigate the effect of the Kendall tolling arrangement through 2008.

This segment s results for 2004 also reflect the impact of fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold and include $10 million in gains associated with the mark-to-market value of certain legacy gas contracts which had previously been accounted for on an accrual basis.

REG. Operating income for the REG segment was $139 million in 2004. The 2004 period includes a $58 million charge related to the sale of Illinois Power and a $54 million charge for the impairment of assets associated with this segment.

Other. Other operating loss was $393 million in 2005, compared to a loss of $284 million in 2004. Results for 2005 include a $236 million charge associated with the recent settlement of our shareholder class action litigation and other legal settlement charges totaling $13 million.

Results for 2005 also include an $11 million charge associated with our December 2005 restructuring. Results for 2004 include approximately $92 million of expenses related to legal and settlement charges. The legal charges resulted from additional activities during the period that affected management s assessment of the probable and estimable loss associated with the applicable proceedings. In addition, 2005 results benefited from lower compensation, insurance and external consultant costs compared to the same period in 2004.

Earnings from Unconsolidated Investments

Earnings from unconsolidated investments were $2 million for the year ended December 31, 2005, compared to $192 million for the year ended December 31, 2004.

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Power Generation Midwest Segment. Earnings from unconsolidated investments for GEN-MW were $7 million for the year ended December 31, 2005, compared to $80 million for the year ended December 31, 2004. Both periods included $7 million of earnings related to our Rocky Road investment, which we own jointly with NRG Energy. 2004 earnings also included a gain of $75 million related to our sale of our 20% interest in the Joppa power generation facility. Additionally, 2004 earnings included an $8 million impairment related to the sale of our 50% interest in the Michigan Power generating facility, which, when netted against our earnings from the investment for 2004, resulted in a $2 million net loss.

Power Generation South Segment. Losses from unconsolidated investments for GEN-SO were $5 million for 2005, compared with earnings of $112 million for 2004.

For 2005, our 50% interest in our investment in Black Mountain (Nevada Cogeneration) reported earnings of $5 million; however, these earnings were more than offset by a $13 million impairment charge. This charge is the result of a decline in value of the investment related to the high cost of fuel in relation to a third party power purchase agreement through 2023 for 100% of the output of the facility. This agreement provides that Black Mountain (Nevada Cogeneration) will receive payments that decrease over time. Additionally, in 2005 we recorded a $10 million impairment charge related to our investment in West Coast Power, related to the pending sale of our 50% interest in the investment to our partner, NRG. This charge almost completely offset the $11 million of 2005 earnings from the investment. Finally, 2005 earnings include $6 million of earnings from our investment in a generating facility located in Panama, which were largely offset by a $4 million impairment charge associated with the pending sale of our 50% interest in this facility.

Our West Coast Power investment was the primary driver of equity earnings in this segment during 2004. Total earnings from the investment of $165 million in 2004 were partially offset by an impairment charge of $85 million triggered by the expiration of West Coast Power s CDWR contract, resulting in net earnings of $80 million. Earnings for 2004 also include a gain of $15 million on the sale of our 50% interest in the Oyster Creek facility in Texas. In addition to the gain on sale, we reported $5 million of earnings from the Oyster Creek investment. In September 2004, we sold our 50% interest in the Hartwell facility, resulting in a gain of approximately $2 million. Our 2004 earnings from Hartwell, including this gain, were $4 million. Our 2004 earnings also included approximately $2 million from Commonwealth, which we sold in the fourth quarter 2004. Finally, our 2004 earnings included $5 million from our investment in Black Mountain (Nevada Cogeneration).

Other Items, Net

Other items, net totaled $26 million of income in 2005, compared to $9 million in 2004. The increase is primarily associated with higher interest income in 2005 due to higher cash balances and higher interest rates.

Interest Expense

Interest expense totaled $389 million in 2005, compared to $453 million in 2004. The decrease is primarily attributable to lower average principal balances in 2005, resulting from the sale of Illinois Power in September 2004 partially offset by the acquisition of Sithe in early 2005 and the increases in LIBOR, and decreased amortization of debt issuance costs in 2005.

Income Tax Benefit

We reported an income tax benefit from continuing operations of $395 million in 2005, compared to an income tax benefit from continuing operations of $172 million in 2004. The 2005 effective tax rate was 33%, compared to 49% in 2004. The 2005 tax benefit includes an $18 million expense and $13 million expense related to an increase in the valuation allowance associated with capital losses and foreign NOLs, respectively. The 2004 tax benefit includes a $27 million benefit related to a reduction in a deferred tax capital losses valuation allowance associated with anticipated gains on asset sales and a $9 million benefit primarily related to IRS and state audits and settlements and other items. Excluding these items from the 2005 and 2004 calculations would

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result in effective tax rates of 36% in 2005 and 39% in 2004. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Please read Note 14 Income Taxes beginning on page F-48 for further discussion of our income taxes.

Discontinued Operations

Income From Discontinued Operations Before Taxes. Discontinued operations include our global liquids business and DMSLP in our NGL segment, our U.K. CRM business and U.K. natural gas storage assets in the CRM segment and our communications business in Other and Eliminations. The following summarizes the activity included in income from discontinued operations:

Year Ended December 31, 2005

	U.K. CRM	DGC	NGL	Other	Total
			(in millions)		
Operating income included in income from discontinued operations	$	$	$ 1,320	$	$ 1,320
Earnings from unconsolidated investments included in income from discontinued operations			5		5
Other items, net included in income from discontinued operations	6		(22)		(16)
Interest expense included in income from discontinued operations					(53)
Income from discontinued operations before taxes					1,256
Income tax expense					(344)
Income from discontinued operations					$ 912

Year Ended December 31, 2004

	U.K. CRM	DGC	NGL	Other	Total
			(in millions)		
Operating income included in income from discontinued operations	$ 1	$	$ 293	$	$ 294
Earnings from unconsolidated investments included in income from discontinued operations			10		10
Other items, net included in income from discontinued operations	18	3	(22)		(1)
Interest expense included in income from discontinued operations					(27)

Income from discontinued operations before taxes	276
Income tax expense	(111)
Income from discontinued operations	$ 165

As further discussed in Note 4 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids beginning on page F-27, on October 31, 2005, we completed the sale of DMSLP. As a result of the sale, and as required by Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we have reclassified the operations related to DMSLP, which comprised of the remaining operations of our NGL segment, from continuing operations to discontinued operations.

In 2005, pre-tax income from discontinued operations of $1,256 million ($912 million after-tax) included $1,250 million in pre-tax income attributable to NGL. In 2004, pre-tax income from discontinued operations of

$276 million ($165 million after-tax) included $254 million in pre-tax income attributable to NGL. Included in NGL s 2005 pre-tax income is a pre-tax gain on the sale of DMSLP of $1,087 million and income attributable to ten months of operations. NGL s pre-tax income in 2004 included income attributable to twelve months of operations, as well as pre-tax gains of $17 million, $16 million and $36 million, respectively, from our Hackberry LNG, Sherman processing plant and Indian Basin sales, offset by an impairment of $5 million for our Puckett gas treating plant and gathering system due to rapidly depleting reserves associated with that facility.

In accordance with EITF Issue 87-24, Allocation of Interest to Discontinued Operations, we have allocated interest expense to discontinued operations associated with debt instruments that were required to be paid upon the sale of DMSLP. Interest expense included in income from discontinued operations, which includes interest incurred on our term loan scheduled to mature in 2010 and our Generation facility debt scheduled to mature in 2007, totaled $53 million and $27 million for 2005 and 2004, respectively.

Income Tax Expense From Discontinued Operations. We recorded an income tax expense from discontinued operations of $344 million in 2005, compared to an income tax expense from discontinued operations of $111 million in 2004. These amounts reflect effective rates of 27% and 40%, respectively. The income tax expense in 2005 includes a $134 million benefit associated with reducing a valuation allowance related to our capital loss carryforward, which primarily relates to our third quarter 2002 sale of NNG. We reduced the valuation allowance related to our capital loss carryforward as a result of capital gains recognized from our sale of DMSLP. For further information regarding the sale, please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids beginning on page F-27. The income tax expense in 2004 includes $20 million in tax expenses related to the conclusion of prior year tax audits. Excluding these items, the 2005 and 2004 effective tax rates would be 38% and 33%, respectively. In general, differences between these effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax differences.

Cumulative Effect of Change in Accounting Principle

On December 31, 2005, we adopted FIN No. 47. In connection with its adoption, we realized a cumulative effect loss of approximately $5 million ($7 million pre-tax). For further information, please see Note 2 Accounting Policies Asset Retirement Obligations beginning on page F-14.

Year Ended 2004 Compared to Year Ended 2003

Operating Loss

Operating loss was $100 million for the year ended December 31, 2004, compared to $769 million for the year ended December 31, 2003.

Power Generation Midwest Segment. Operating income for GEN-MW, where we produced approximately 60% of our generated volumes, was $194 million for the year ended December 31, 2004, compared to $196 million for the year ended December 31, 2003. Increased prices contributed $23 million for 2004 compared to 2003. Additionally, we experienced a $28 million reduction in coal transportation costs in GEN-MW, resulting from a transportation contract which took effect at the beginning of 2004. However, improved pricing was partially offset by an increase in operating expenses for GEN-MW of approximately $12 million, resulting from the timing of maintenance expenditures, as well as increases in labor costs. Additionally, we reported $17 million less capacity revenue in 2004 as compared with 2003. Volumes were down slightly, from 21.1 million MWh for 2003 to 20.7 million MWh for 2004. This decrease was largely due to reduced production at our Havana facility, resulting from our management of fuel inventories in anticipation of our switch to PRB coal. Our 2004 results include $16 million of mark-to-market losses, compared with $3 million of losses in 2003. Results from our gas-fired peaking facilities decreased from $2 million in 2003 to a loss of $4 million in 2004. Additionally, results were affected by an $8 million increase in depreciation expense, resulting from the completion of our Rolling Hills generation facility, as well as other capital projects placed into service in 2003. General and administrative expense increased slightly, from $37 million in 2003 to $38 million in 2004.

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Power Generation Northeast Segment. Operating income for GEN-NE was $21 million for the year ended December 31, 2004, compared to $46 million for the year ended December 31, 2003. This decrease was primarily the result of pricing effects year over year, as increased fuel costs more than offset an increase in power prices. This resulted in a $21 million reduction in earnings. Additionally, we realized $11 million less revenue in 2004 under a transitional power purchase agreement, which expired in October 2004. Operating expense in GEN-NE was up $3 million year over year as a result of increased labor and tax expense. However, these reductions in earnings were partially offset by a 7% increase in volumes, which contributed an additional $6 million, largely the result of the dual fuel capabilities of our Roseton unit. GEN-NE results also included $17 million and $20 million of mark-to-market gains in 2004 and 2003, respectively. Depreciation increased slightly, from $9 million in 2003 to $10 million in 2004, while general and administrative expense remained flat at $13 million in both periods.

Power Generation South Segment. Operating loss for GEN-SO was $52 million for the year ended December 31, 2004, compared to a loss of $48 million for the year ended December 31, 2003. Results from our peaking facilities in the Southeast decreased by $25 million, primarily as a result of the loss of capacity revenues related to a contract that expired at the end of 2003. Results from our ERCOT facility improved by $8 million, from a loss of $20 million in 2003 to a loss of $12 million in 2004. Additionally, 2003 results included a charge of $11 million related to a comprehensive settlement agreement with a manufacturer of turbines in which we agreed in principle to forfeit a prepayment in the amount of $11 million. GEN-SO results included mark-to-market losses of $8 million and $6 million in 2004 and 2003, respectively. Depreciation decreased from $30 million in 2003 to $25 million in 2004.

CRM. Operating loss for the CRM segment was $118 million for 2004, compared to operating loss of $385 million in 2003.

Results for 2004 were impacted by the following items:

- $88 million gain associated with the exit of four natural gas transportation agreements in support of our third party marketing business; and
- $115 million charge associated with our entry into a back-to-back power purchase agreement with a subsidiary of Constellation Energy in November 2004 to mitigate the effect of the Kendall tolling arrangement through 2008.

This segment s results for 2004 also reflect the impact of fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold and include $10 million in gains associated with the mark-to-market value of certain legacy gas contracts which had previously been accounted for on an accrual basis.

Results for 2003 were impacted by the following pre-tax losses:

- $133 million charge associated with the settlement of power tolling arrangements with Southern Power, for which we paid $155 million;
- $121 million mark-to-market loss on contracts associated with the Independence power tolling arrangement;

$34 million charge associated with the cash settlement of the Batesville tolling arrangement; and

$30 million charge associated with the settlement of power supply agreements with Kroger, for which we received approximately $110 million.

Additionally, 2003 results include gains from the sale of natural gas inventories offset by changes in the value of our remaining marketing and trading activity, and fixed payments on our power tolling arrangements in excess of realized margins on power generated and sold.

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REG. Operating income for the REG segment was $139 million in 2004, which included income prior to our sale of Illinois Power to Ameren on September 30, 2004, compared to a loss of $327 million in 2003. The 2004 period includes a $58 million charge related to the loss on the sale of Illinois Power and a $54 million impairment of Illinois Power assets. We also stopped depreciating our Illinois Power assets on February 1, 2004, as they were classified as held for sale, which resulted in a benefit to operating income of $111 million compared to the 2003 period. The 2003 period includes an operating loss for the fourth quarter 2003 of $485 million, which was not experienced in 2004, due to the September 2004 sale of Illinois Power. Included in the fourth quarter 2003 activity is a $529 million charge for the impairment of goodwill and other assets associated with this segment, as further described in Note 11 Goodwill and Intangible Assets beginning on page F-41 and $30 million of depreciation expense.

Operationally, residential and commercial electric sales volumes for the first nine months of 2004 were negatively impacted by warmer than average winter weather compared to 2003. Industrial electric sales were negatively affected by customers choosing alternate energy providers. These decreases were more than offset by lower overall operating costs, which were primarily due to the reimbursement of MISO exit fees and RTO development costs totaling approximately $10 million and lower departmental spending, partially offset by higher employee benefit costs. Residential and commercial electric sales volumes were relatively flat in 2004 as compared to 2003 due to cooler summer weather offset by warmer spring weather.

Other. Other operating loss was $284 million in 2004, compared to $251 million in 2003. The losses in 2004 and 2003 primarily relate to general and administrative expenses and depreciation and amortization expenses which are incurred at a corporate level. The higher loss in 2004 related primarily to increased legal and settlement charges, costs related to compliance with Section 404 of the Sarbanes-Oxley Act and higher professional fees.

Operating loss for 2004 includes approximately $92 million of expenses related to legal and settlement charges. Operating loss for 2003 includes legal charges of $50 million. The legal charges in both periods resulted from additional activities during each period that affected management s assessment of the probable and estimable loss associated with the applicable proceedings.

Earnings from Unconsolidated Investments.

Earnings from unconsolidated investments were $192 million for the year ended December 31, 2004, compared to $126 million for the year ended December 31, 2003.

Power Generation Midwest Segment. Earnings from unconsolidated investments for GEN-MW were $80 million for the year ended December 31, 2004, compared to $15 million for the year ended December 31, 2003. Both periods included $7 million of earnings related to our Rocky Road investment, which we own jointly with NRG Energy. 2004 earnings also included a gain of $75 million related to our sale of our 20% interest in the Joppa power generation facility. Additionally, 2004 earnings included an $8 million impairment related to the sale of our 50% interest in the Michigan Power generating facility, which when netted against our earnings from the investment for 2004, resulted in a $2 million net loss. 2003 earnings include $5 million and $3 million from Michigan Power and Joppa, respectively.

Power Generation South Segment. Earnings from unconsolidated investments for GEN-SO were $112 million for 2004, compared with earnings of $113 million for 2003.

Our West Coast Power investment was the primary driver of equity earnings for 2004. Total earnings from the investment of $165 million in 2004 were partially offset by an impairment charge of $85 million triggered by the expiration of West Coast Power s CDWR contract, resulting in net earnings of $80 million. Earnings for 2004 also include a gain $15 million on the sale of our 50% interest in the Oyster Creek facility in Texas. In addition

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to the gain on sale, we reported $5 million of earnings from the Oyster Creek investment. In September 2004, we sold our 50% interest in the Hartwell facility, resulting in a gain of approximately $2 million. Our 2004 earnings from Hartwell, including this gain, were $4 million. Our 2004 earnings also included approximately $2 million from Commonwealth and $5 million from our investment in Black Mountain (Nevada Cogeneration).

West Coast Power s Earnings of $137 million for 2003 were partially offset by a $20 million charge associated with our 50% share of a goodwill impairment charge recorded by West Coast Power in the fourth quarter 2003. Earnings of $22 million from our remaining U.S. and international investments were more than offset by a $26 million impairment.

CRM. CRM s losses from unconsolidated investments were zero during 2004 compared to $2 million in 2003. As of December 31, 2003, CRM has no material unconsolidated investments. As such, future results are expected to be immaterial.

Other Items, Net

Other items, net consists of other income and expense items, net, minority interest income (expense) and accumulated distributions associated with trust preferred securities. Other items, net totaled $9 million and $37 million for 2004 and 2003, respectively.

The 2004 results included $12 million in interest income.

The 2003 results included the following items:

- $17 million in interest income;
- $20 million in minority interest income;
- $11 million gain on foreign currency transactions; offset by
- $8 million charge for accumulated distributions associated with trust preferred securities.

Interest Expense

Interest expense totaled $453 million for 2004, compared with $503 million for 2003.

The decrease in 2004, as compared to 2003, is primarily attributable to the following:

- Lower average principal balances in the 2004 period (approximately $69 million of the decrease);
- Decreased amortization of debt issuance costs (approximately $28 million of the decrease);
- Lower letter of credit fees (approximately $12 million of the decrease). The lower letter of credit fees resulted from the restructuring of our credit facility in May 2004, with respect to which such fees are lower than those contained in our previous facility.

These items were offset by higher average interest rates on borrowings (approximately $61 million), including the new notes issued in connection with our August 2003 refinancing.

Income Tax Benefit

We reported an income tax benefit from continuing operations of $172 million in 2004, compared to an income tax benefit from continuing operations of $296 million in 2003. These amounts reflect effective rates of 49% and 27%, respectively. The 2004 tax benefit includes a $27 million benefit related to a reduction in a deferred tax capital losses valuation allowance associated with gains on asset sales and a $9 million benefit primarily related to IRS and state audits and settlements and other items. The 2003 effective rate was impacted significantly by the $311 million goodwill impairment relating to the REG segment. As there was no tax basis in

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the goodwill impaired in 2003, there were no tax benefits associated with the charge. Additionally, the 2003 tax benefit includes a $21 million reduction in a valuation allowance associated with our capital loss carryforward as a result of capital gains recognized in 2003 or anticipated to be recognized in early 2004 related to various dispositions. Excluding these items from the 2004 and 2003 calculations would result in effective tax rates of 39% and 34%, respectively. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Please read Note 14 Income Taxes beginning on page F-48 for further discussion of our income taxes.

Discontinued Operations

Income From Discontinued Operations Before Taxes. Discontinued operations include our global liquids business and DMSLP in our NGL segment, our U.K. CRM business and U.K. natural gas storage assets in the CRM segment and our communications business in Other and Eliminations. The following summarizes the activity included in income from discontinued operations:

Year Ended December 31, 2004

	U.K. CRM	DGC	NGL	Other	Total
			(in millions)		
Operating income included in income from discontinued operations	$ 1	$	$ 293	$	$ 294
Earnings from unconsolidated investments included in income from discontinued operations			10		10
Other items, net included in income from discontinued operations	18	3	(22)		(1)
Interest expense included in income from discontinued operations					(27)
Income from discontinued operations before taxes					276
Income tax expense					(111)
Income from discontinued operations					$ 165

Year Ended December 31, 2003

	U.K. CRM	DGC	NGL	Other	Total
			(in millions)		
Operating income included in income from discontinued operations	$ (10)	$ 7	$ 173	$ (2)	$ 168
Earnings from unconsolidated investments included in income from discontinued operations			(2)		(2)

Other items, net included in income from discontinued operations	(21)	(17)	(38)
Interest expense included in income from discontinued operations			(6)
Income from discontinued operations before taxes			122
Income tax expense			(41)
Income from discontinued operations			$ 81

As further discussed in Note 4 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids beginning on page F-27, on October 31, 2005, we completed the sale of DMSLP which comprised the NGL segment prior to the sale. As a result of the sale and as required by SFAS No. 144, we have reclassified the operations of the remaining NGL segment, primarily related to DMSLP, from continuing operations to discontinued operations.

In 2004, pre-tax income from discontinued operations of $276 million ($165 million after-tax income) included $254 million in pre-tax income attributable to NGL. In 2003, pre-tax income from discontinued operations of $122 million ($81 million after-tax) included $148 million in pre-tax income attributable to NGL.

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Included in NGL s 2004 pre-tax income are pre-tax gains of $17 million, $16 million and $36 million, respectively, from our Hackberry LNG, Sherman processing plant and Indian Basin sales, offset by an impairment of $5 million at our Puckett gas processing facility. NGL s pre-tax income for 2003 included a $25 million gain on sale of our ownership interest in the Hackberry LNG facility and a $3 million gain associated with the expiration of an environmental indemnity obligation. Additionally, NGL s 2003 results were negatively impacted by a $12 million pre-tax impairment on our minority investment in GCF related to the difference between our book value and indicative bids received related to the possible sale of our minority investment.

In accordance with EITF Issue 87-24, Allocation of Interest to Discontinued Operations, we have allocated interest expense to discontinued operations associated with debt instruments that were required to be paid upon the sale of DMSLP. Interest expense included in income from discontinued operations, which includes interest incurred on our term loan scheduled to mature in 2010 and our Generation facility debt scheduled to mature in 2007, totaled $27 million and $6 million for 2004 and 2003, respectively.

Income Tax Expense From Discontinued Operations. We reported an income tax expense from discontinued operations of $111 million in 2004, compared to an income tax expense from discontinued operations of $41 million in 2003. These amounts reflect effective rates of 40% and 34%, respectively. The 2004 tax expense includes $20 million in tax expenses related to the conclusion of prior year tax audits partially offset by translation gains recognized on the repatriation of cash from the U.K. Please read Note 14 Income Taxes beginning on page F-48 for further discussion. Excluding this item from the 2004 calculations would result in an effective tax rate of 33%. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Cumulative Effect of Change in Accounting Principles

We reflected EITF Issue 02-03 s rescission of EITF Issue 98-10 effective January 1, 2003 as a cumulative effect of change in accounting principle. The net impact was a pre-tax benefit of $33 million ($21 million after-tax), of which a benefit of $43 million was recognized in our CRM segment and a charge of $10 million was recognized in our Generation business. We also adopted SFAS No. 143 effective January 1, 2003 and recognized a pre-tax benefit of $54 million ($34 million after-tax) associated with its implementation. The $54 million benefit was split between our power generation business ($57 million) and our REG segment ($(3) million). Finally, we adopted certain provisions of FIN No. 46R in the fourth quarter 2003 and recognized a pre-tax charge of $23 million ($15 million after-tax) in our GEN-SO segment related to our CoGen Lyondell facility.

Please read Note 2 Accounting Policies beginning on page F-11 for further discussion of our adoption of recent accounting policies.

2006 Outlook

The following summarizes our 2006 outlook for our power generation business and our customer risk management business.

Power Generation Business. Generally, we expect that future financial results of the generation business will continue to reflect sensitivity to underlying fuel commodity prices and market prices for energy, ancillary services and capacity, transportation and transmission logistics, weather conditions and in-market asset availability. Although we will continue our efforts to manage price risk through the optimization of fuel procurement, we expect to limit long-term forward sales of power and related transactions in order to capture short-term market pricing opportunities. Adverse changes in prices will expose us to lower earnings.

GEN- MW. We expect our results to continue to be impacted by power prices in the market and fuel availability. Although we expect prices to continue to remain high in the Midwest, we will not be able to fully

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realize these prices, due to volume options held by AmerenIP in our power purchase agreement with them. Under the terms of our power purchase agreement, which expires at the end of 2006, AmerenIP can take up to 2800 MW of energy and ancillary services in each hour at $30/MWh from May-September and up to 2300 MW of energy and ancillary services in each hour at $30/MWh during the other months. However, the PPA contains quarterly and annual limitations on the amount of MWhs that AmerenIP can take. Additionally, AmerenIP may request up to another 150 MW in each hour at a market based price. Beyond 2006, results in the Midwest will be affected by expiration of this power purchase agreement. Expiration of this contract will result in increased exposure to volatility in market prices, and could allow us to realize additional benefits in a strong price environment.

Another factor impacting our results in the Midwest beyond 2006 will be the regulatory environment in Illinois. In January 2006, the Illinois Commerce Commission approved proposals by the two major Illinois electric utilities to hold an auction as the means by which they will procure capacity and energy necessary to serve load after 2006. While the ICC issued orders approving a reverse auction process, there remains a possibility of substantial challenges to these orders and the power of the ICC to issue them. Thus it is difficult to predict (i) whether an auction or some other mechanism(s), if any, will be approved in advance of 2007, and (ii) what impact an auction or lack thereof will have on our results.

Operation of our Midwest generation facilities is dependent on our ability to procure coal. Power generators have experienced significant pressures on available coal supplies that are either transportation or supply related. Our long-term supply and transportation agreements for our Midwest fleet largely mitigate these concerns; however, railroad maintenance has resulted in decreased delivery certainty since May 2005, especially in the month of October. Should this situation persist at levels similar to those experienced in 2005, we may re-implement a program to selectively conserve coal during off-peak periods, foregoing the revenue associated with this off-peak production to ensure adequate coal supply for on-peak load during 2006. A similar approach was successful in the fourth quarter of 2005. As a result, we expect we will be able to maintain an adequate level of coal inventories throughout 2006.

During 2005, our results reflected increases in the market for capacity-related products from our peaking and intermediate generation facilities. We benefited from operation of all of our peaking plants at certain times during the summer months of 2005. Based on increased demand and market design changes, including the implementation of a fully-functioning market in MISO in 2005, we continue to expect a contribution from our peaking and intermediate generation facilities in the summer months of 2006. This will be largely subject to the market demand and will therefore be heavily impacted by weather.

GEN-NE. We expect commodity fuel prices and market prices for energy and capacity to continue to be high, although these prices are off of the highs seen in the forward markets in the fall of 2005. Spreads are expected to remain volatile as fuel prices change. Warmer than normal temperatures at the start of 2006 have resulted in lower than expected demand in January. As a result, we expect year-to-year decreased runtime in the first half of 2006, particularly at our Roseton facility. Our results are also dependent on our ability to maintain coal and oil deliveries to the facilities. We continue to maintain sufficient coal and oil inventories and contractual commitments to provide us with a stable fuel supply. Additionally, our results could be affected by potential changes in New York state environmental regulations, as well as our ability to obtain permits necessary for the operation of our facilities. For further discussion of these matters, please see Note 18 Regulatory Issues Roseton State Pollutant Discharge Elimination System Permit beginning on page F-65 and Note 18 Regulatory Issues Danskammer State Pollutant Discharge Elimination System Permit beginning on page F-66, respectively.

GEN-SO. We entered into an agreement on September 6, 2005 to extend the steam and energy sales component of an ongoing relationship to sell up to approximately 80 MW of energy and 1.5 million pounds per hour of steam from our CoGen Lyondell cogeneration facility to Lyondell Chemical Company (LCC) for an initial term from January 2007 through December 2021 and subsequent automatic rollover terms of two years

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each thereafter through December 2046. Expected incremental annual operating income of approximately $30 million for the ERCOT region beyond 2006 is associated primarily with this contract, which allows us to recover our operating costs. However, we retain our ability to capture market upside in the Texas region for the excess generation from Lyondell.

Our peaking facilities in the South continue to contribute revenue from sales of capacity to mainly the local load-serving entities or wholesale buyers. We currently have a substantial portion of our portfolio committed on an annual basis through 2015. Where we have uncommitted capacity and energy, we believe opportunities to sell additional capacity from these facilities will develop at times during the year. Due to the regulated, non-liquid market available in this region, our results will be impacted by our ability to complete additional sales to a limited pool of buyers for these products.

West Coast Power (our 50/50 joint venture co-owned with NRG Energy) was only a modest contributor to our 2005 profitability, and we expect mixed results for this business to continue until California s efforts to re-formulate their wholesale electric market come to fruition. As a result, on December 27, 2005, we entered an agreement to sell our 50% interest to NRG Energy for $205 million. We expect this sale to close by early 2006; thus, West Coast Power will not materially contribute to our 2006 results. Please read Item 1. Business Segment Discussion Power Generation South Segment South Fleet Equity Investments West Coast Power beginning on page 14 for a discussion of West Coast Power s current contractual arrangements.

CRM. Our CRM business segment s future results of operations will be significantly impacted by our ability to complete our exit from this business. Our CRM business remains a party to certain legacy gas and power transactions, most of which have been hedged. However, we expect to continue to incur cash outflows associated with the legacy transactions. In 2006, based on our current pricing forecasts, cash outflow from our CRM business, exclusive of the Sterlington settlement which closed on March 7, 2006, would be approximately $10 million, however this expectation would change with changes in commodity prices. We are proactively working with our customers to exit the remainder of our obligations on economically favorable terms.

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CASH FLOW DISCLOSURES

The following table includes data from the operating section of the consolidated statements of cash flows and include cash flows from our discontinued operations, which are disclosed on a net basis in loss on discontinued operations, net of tax, in the consolidated statements of operations:

	Years Ended December 31,		
	2005	2004	2003
		(in millions)	
Operating cash flows from our generation businesses	$ 472	$ 421	$ 428
Operating cash flows from our customer risk management business	(21)	(371)	496
Operating cash flows from our natural gas liquids business	288	278	186
Operating cash flows from Illinois Power		213	67
Other operating cash flows	(769)	(536)	(301)
Net cash provided by (used in) operating activities	$ (30)	$ 5	$ 876

Operating Cash Flow. Our cash flow used in operations totaled $30 million for the twelve months ended December 31, 2005. During the period, our power generation business provided positive cash flow from operations of $472 million, due primarily to positive earnings for the period as well as the return of cash collateral of approximately $66 million during 2005. This was offset by increased accounts receivable balances due to higher prices at December 31, 2005 as compared to December 31, 2004. Our customer risk management business had cash outflows of approximately $21 million, due primarily to fixed payments associated with the Sterlington and Gregory power tolling arrangements and our final payment of $26 million related to our exit from four long-term natural gas transportation contracts. This was offset partially by the return of approximately $43 million of cash collateral during 2005. Our discontinued natural gas liquids business provided cash flow from operations of $288 million due primarily to positive earnings for the period as well as the return of cash collateral. Other and Eliminations includes a use of approximately $769 million in cash due primarily to our payments of $255 million in connection with the settlement of the shareholder class action litigation, interest payments to service debt, pension plan contributions of approximately $31 million, state tax payments and general and administrative expenses.

Our cash flow provided by operations totaled $5 million for the 12 months ended December 31, 2004. During the period, our power generation business provided positive cash flow from operations of $421 million due primarily to positive earnings for the period and increased business activity, partially offset by increased cash collateral posted in lieu of letters of credit. Our customer risk management business used approximately $371 million in cash due primarily to fixed payments associated with the power tolling arrangements and related gas transportation agreements, a $117.5 million payment related to the restructuring of the Kendall toll, increased cash collateral posted in lieu of letters of credit and our exit from four long-term natural gas transportation contracts. Our discontinued natural gas liquids business provided cash flow from operations of $278 million due primarily to positive earnings, partially offset by increased prepayments due to higher sales. Illinois Power provided cash flow from operations of $213 million due primarily to positive earnings for the period. Other & Eliminations includes a use of approximately $536 million in cash due primarily to interest payments to service debt, settlement payments and general and administrative expenses.

Cash provided in 2003 relates primarily to collateral returns, settlements of risk management assets and sales of natural gas storage of approximately $500 million from our customer risk management business, a $110 million income tax refund and solid operational performances from our power generation business, our discontinued natural gas liquids business and Illinois Power. Despite a relatively weak commodity price environment, our power generation business provided cash flows in excess of $400 million, due largely to effective commercial and operational management and our coal- and dual-fired generation assets. Similarly, our discontinued natural gas liquids business contributed cash flows from operations in excess of $180 million due to a strong commodity price environment, particularly in the upstream business, offset by increases in prepayments

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and lower downstream results due to industry-wide reductions in volumes available for fractionation. Illinois Power contributed operating cash flows in excess of $60 million, primarily from normal operating conditions, offset by working capital outflows due to increased injection of gas into storage, as well as an increase in prepayments. General and administrative costs, a $45 million litigation settlement and continued extinguishment of liabilities during our exit from our communications business offset these positive operational cash flows during 2003.

Capital Expenditures and Investing Activities. Cash provided by investing activities during the twelve months ended December 31, 2005 totaled $1,824 million. Capital spending of $195 million was primarily comprised of $113 million, $21 million, $9 million and $45 million in the GEN-MW, GEN-NE, GEN-SO and NGL segments, respectively. The capital spending for our GEN-MW segment primarily related to maintenance capital projects, as well as $17 million and $10 million in development capital associated with the completion of the Vermilion and Havana PRB conversions, respectively. Capital spending for our GEN-NE and GEN-SO segments primarily related to maintenance and environmental projects. Capital spending in our NGL segment primarily related to maintenance capital projects and wellconnects.

The cost to acquire Sithe Energies, net of cash proceeds, totaled $120 million. The increase in restricted cash of $353 million related primarily to a $335 million deposit associated with our cash collaterized facility, as well as an $18 million increase in the Independence restricted cash balance.

Net cash proceeds from asset sales of $2,488 million consisted of the following items:

- $2,382 million, net of transaction costs, from the sale of DMSLP;
- a $100 million return of funds held in escrow offset by a $5 million payment to Ameren associated with a working capital adjustment, both of which related to the sale of Illinois Power; and
- $10 million from the sale of land at our Port Everglades facility.

Net cash provided by investing activities during 2004 totaled $262 million. Capital spending of $311 million was comprised primarily of $113 million, $17 million, $15 million, $61 million and $92 million in the GEN-MW, GEN-NE, GEN-SO, NGL and REG segments, respectively. The capital spending for our GEN-MW segment primarily related primarily to maintenance capital projects, as well as approximately $41 million related to developmental projects. Capital spending for our GEN-NE and GEN-SO primarily related to maintenance and environmental projects. Capital spending in our NGL segment related primarily to maintenance capital projects and wellconnects, as well as approximately $21 million on developmental projects. Capital spending in our REG segment related primarily to projects intended to maintain system reliability and new business services.

Net cash proceeds from asset sales of $576 million consisted of the following items:

- $217 million from the sale of Illinois Power, net of cash retained by Illinois Power of $52 million;

$152 million from the sale of our equity investments in the Oyster Creek, Hartwell, Michigan Power, Jamaica and Commonwealth generating facilities;

$99 million from the sale of Joppa;

$48 million from the sale of Indian Basin;

$34 million from the sale of Sherman;

$17 million from the sale of our remaining financial interest in the Hackberry LNG project; and

$9 million from the sale of PESA.

The cash proceeds were partially offset by $3 million of capitalized business acquisition costs incurred in connection with the Sithe Energies acquisition.

Cash used in investing activities for 2003 totaled $266 million. Our capital spending totaled $333 million and was primarily comprised of routine capital maintenance of our existing asset base. Of this amount, we spent approximately $40 million on the construction of Rolling Hills, which began commercial operations in June

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2003. Our proceeds from asset sales totaled approximately $72 million and primarily relate to our sale of Hackberry LNG Terminal LLC ($35 million), SouthStar ($20 million), and generation equity investments ($25 million), which were offset by $10 million in cash outflows associated with the sale of our European communications business.

Financing Activities. Cash used in financing activities during the twelve months ended December 31, 2005 totaled $873 million. Repayments of long-term debt totaled $1,432 million for the twelve months ended December 31, 2005 and consisted of the following payments:

- $600 million aggregate principal outstanding revolver due May 2007 in November 2005;
- $597 million on the term loan;
- $183 million on the Riverside facility debt;
- $34 million on the Independence Senior Notes due 2007; and
- $18 million on a maturing series of DHI senior notes.

The repayments were partially offset by proceeds from the October 2005 draw-down on the $600 million aggregate principal outstanding revolver due May 2007. Cash used in financing activities also includes semi-annual dividend payments totaling $22 million on our Series C preferred stock and distributions of $25 million to minority interest owners.

Net cash used in financing activities during the 2004 totaled $115 million. Our financing cash outflows were primarily related to repayments of long-term debt totaling $650 million and consisted primarily of the following payments:

- $223 million to redeem the outstanding Chevron junior notes;
- $185 million under our ABG Gas Supply financing;
- $95 million for a maturing series of Illinova senior notes;
- $78 million on the Tilton capital lease; and
- $65 million on Illinois Power s transitional funding trust notes.

These repayments of long-term debt were offset by proceeds from our $600 million aggregate principal outstanding secured term loan, net of issuance costs of $19 million. We made semi-annual dividend payments totaling $22 million on our Series C preferred stock and made distributions to minority interest owners totaling $32 million.

During 2003, cash used for financing activities totaled $900 million. The following summarizes significant items:

Repayments of $128 million, net, under our revolving credit facilities.

Long-term debt proceeds, net of issuance costs, for 2003 totaled $2.2 billion and consisted of: (1) $311 million associated with the October 2003 follow-on offering of the DHI notes; (2) $1,607 million associated with our August 2003 refinancing transaction, (3) $142 million from the delayed issuance of $150 million in Illinois Power 11.5% Mortgage Bonds due 2010 and (4) $159 million from the Term A loan drawn in connection with the April 2003 credit facility restructuring.

In connection with the Series B Exchange, we made a $225 million cash payment to Chevron.

Repayments of long-term debt totaled $2.7 billion and consisted of: (1) $696 million prepayment of the outstanding balance under the Black Thunder financing; (2) $609 million purchase of DHI s previously outstanding 2005/2006 senior notes; (3) $360 million prepayment of the Term B loan outstanding under DHI s April 2003 restructured credit facility; (4) $200 million prepayment of the Term A loan

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outstanding under DHI s April 2003 restructured credit facility; (5) $200 million in payments under the Renaissance and Rolling Hills interim financing; (6) $190 million in payments of Illinois Power mortgage bond maturities; (7) $100 million payment on Illinois Power s term loan; (8) $165 million payment in full for the GEN facility capital lease; (9) $86 million in payments on Illinois Power s transitional funding trust notes; (10) $74 million in payments under the ABG Gas Supply financing; (11) $62 million in payments under the Black Thunder secured financing prior to its prepayment; (12) $5 million purchase of Illinova senior notes on the open market; and (13) $2 million in payments on the Chevron junior notes.

Distributions to minority interest owners totaling $21 million.

SEASONALITY

Our revenues and operating income are subject to fluctuations during the year, primarily due to the impact seasonal factors have on sales volumes and the prices of power and natural gas. Power marketing operations and generating facilities have higher volatility and demand, respectively, in the summer cooling months. This trend may change over time as demand for natural gas increases in the summer months as a result of increased gas-fired electricity generation.

CRITICAL ACCOUNTING POLICIES

Our Accounting Department is responsible for the development and application of accounting policy and control procedures. This department conducts these activities independent of any active management of our risk exposures, is independent of our business segments and reports to the Chief Financial Officer.

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments. It is possible that materially different amounts could be recorded if these estimates and judgments change or if actual results differ from these estimates and judgments. We have identified the following six critical accounting policies that require a significant amount of estimation and judgment and are considered to be important to the portrayal of our financial position and results of operations:

Revenue Recognition;

Valuation of Tangible and Intangible Assets;

Estimated Useful Lives;

Accounting for Contingencies, Guarantees and Indemnifications;

Accounting for Income Taxes; and

Valuation of Pension Assets and Liabilities.

Revenue Recognition

We utilize two comprehensive accounting models in reporting our consolidated financial position and results of operations as required by GAAP an accrual model and a fair value model. We determine the appropriate model for our operations based on guidance provided in applicable accounting standards and positions adopted by the FASB or the SEC.

The accrual model has historically been used to account for substantially all of the operations conducted in our GEN-MW, GEN-NE and GEN-SO segments. These segments consist largely of the ownership and operation of physical assets that we use in various generation operations. We earn revenue from our facilities in three primary ways: (1) sale of energy generated by our facilities; (2) sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time

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changes in load, and provide emergency reserves for major changes to the balance of generation and load; and (3) sale of capacity. We recognize revenue from these transactions when the product or service is delivered to a customer.

Additionally, the accrual model was used to account for substantially all of the operations conducted in our NGL and REG segments. These segments consisted largely of processing and delivery operations. The business of these segments included the separation of natural gas liquids into their component parts from a stream of natural gas and the transportation or transmission or commodities through pipelines or over transmission lines. End sales from these businesses resulted in physical delivery of commodities to our wholesale, commercial, industrial and retail customers. We recognized revenue from these transactions when the product or service was delivered to a customer.

The fair value model has historically been used to account for forward physical and financial transactions, occurring primarily in the CRM segment and the power generation business, which meet the definition of a derivative contract as defined by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The criteria are complex, but generally require these contracts to relate to future periods, to contain fixed price and volume components and to have terms that require or permit net settlement of the contract in cash or the equivalent. The FASB determined that the fair value model is the most appropriate method for accounting for these types of contracts. In part, this conclusion is based on the cash settlement provisions in these agreements, as well as the volatility in commodity prices, interest rates and, if applicable, foreign exchange rates, which impact the valuation of these contracts. Since these transactions may be settled in cash or the equivalent, the value of the assets and liabilities associated with these transactions is reported at estimated settlement value based on current forward prices and rates as of each balance sheet date.

Typically, derivative contracts can be accounted for in three different ways: (1) as an accrual contract, if the criteria for the normal purchase normal sale exemption are met and documented; (2) as a cash flow or fair value hedge, if the criteria are met and documented or (3) as a mark-to-market contract with changes in fair value recognized in current period earnings. Generally, we only mark-to-market through earnings our derivative contracts if they do not qualify for the normal purchase normal sale exemption or as a cash flow hedge. Because derivative contracts can be accounted for in three different ways, and as the normal purchase normal sale exemption and cash flow and fair value hedge accounting are elective, the accounting treatment used by another party for a similar transaction could be different than the accounting treatment we use.

In order to estimate the fair value of our portfolio of transactions which meet the definition of a derivative and do not qualify for the normal purchase normal sale exemption, we use a liquidation value approach assuming that the ability to transact business in the market remains at historical levels. The estimated fair value of the portfolio is computed by multiplying all existing positions in the portfolio by estimated prices, reduced by a time value of money adjustment and deduction of reserves for credit and price. The estimated prices in this valuation are based either on (1) prices obtained from market quotes, when there are an adequate number of quotes to consider the period liquid, or, if market quotes are unavailable, or the market is not considered to be liquid, (2) prices from a proprietary model which incorporates forward energy prices derived from market quotes and values from previously executed transactions. The amounts recorded as revenue change as these estimates are revised to reflect actual results and changes in market conditions or other factors, many of which are beyond our control.

Valuation of Tangible and Intangible Assets

We evaluate long-lived assets, such as property, plant and equipment, investments and goodwill, when events or changes in circumstances lead to a reduction in the estimated useful lives or estimated future cash flows sufficient to indicate that the carrying value of such assets may not be recoverable. Factors we consider important, which could trigger an impairment analysis, include, among others:

significant underperformance relative to historical or projected future operating results;

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- significant changes in the manner of our use of the assets or the strategy for our overall business;
- significant negative industry or economic trends; and
- significant declines in stock value for a sustained period.

We assess the carrying value of our property, plant and equipment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the related discounted cash flows of the assets and recording a loss if the resulting estimated fair value is less than the book value. For assets identified as held for sale, the book value is compared to the estimated fair value, which may also include estimates based upon comparables or quoted market prices, to determine if an impairment loss is required. Please read Note 5 Restructuring and Impairment Charges beginning on page F-29 for discussion of impairment charges we recognized for 2005, 2004 and 2003.

We follow the guidance of APB 18, The Equity Method of Accounting for Investments in Common Stock, SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities, and EITF No. 02-14, Whether an Investor Should Apply the Equity Method of Accounting to Investments Other Than Common Stock, when reviewing our investments. The book value of the investment is compared to the estimated fair value, based either on discounted cash flow projections or quoted market prices, if available, to determine if an impairment is required. We record a loss when the decline in value is considered other than temporary.

Our assessments regarding valuation of tangible and intangible assets are subject to estimates and judgment of management. Market conditions, energy prices, estimated useful lives of the assets, discount rate assumptions and legal factors impacting our business may have a significant effect on the estimates and judgment of management. If different judgments were applied, estimates could differ significantly. Actual results could vary materially from these estimates.

Estimated Useful Lives

The estimated useful lives of our long-lived assets are used to compute depreciation expense, future asset retirement obligations and are also used in impairment testing. Estimated useful lives are based, among other things, on the assumption that we provide an appropriate level of capital expenditures while the assets are still in operation. Without these continued capital expenditures, the useful lives of these assets could decrease significantly. Estimated lives could be impacted by such factors as future energy prices, environmental regulations, various legal factors and competition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future asset retirement obligations may be insufficient and impairments in carrying values of tangible and intangible assets may result.

Accounting for Contingencies, Guarantees and Indemnifications

We are involved in numerous lawsuits, claims, proceedings, joint venture audits and tax-related audits in the normal course of our operations. In accordance with SFAS No. 5, Accounting for Contingencies, we record a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an ongoing basis to ensure that we have appropriate reserves recorded on the balance sheet. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant. Our estimates and judgment could change based on new information, changes in laws or regulations, changes in management s plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from these reserves.

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Liabilities are recorded when environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability. These assumptions involve the judgments and estimates of management and any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

We follow the guidance of FIN No. 45 Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others for disclosure and accounting of various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification subject of FIN No. 45 is entered into, an estimated fair value of the underlying guarantee or indemnification is recorded. Some guarantees and indemnifications could have significant financial impact under certain circumstances, however management also considers the probability of such circumstances occurring when estimating the fair value. Actual results may materially differ from the estimated fair value of such guarantees and indemnifications.

Under the provisions of SFAS No. 143, Asset Retirement Obligations and FIN No. 47 Accounting for Conditional Asset Retirements, we are required to record legal obligations to retire tangible, long-lived assets on our balance sheet as liabilities, which are recorded at a discount, when the liability is incurred. Significant judgment is involved in estimating our future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. If our estimates on the amount or timing of the cash flow change, the change may have a material impact on our results of operations.

Accounting for Income Taxes

We follow the guidance in SFAS No. 109, Accounting for Income Taxes, which requires that we use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our consolidated balance sheets.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and, to the extent we believe that it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

Management believes future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize assets for which no reserve has been established. While we have considered these factors in assessing the need for a valuation allowance, there is no assurance that a valuation allowance would not need to be established in the future if information about future years change. Any change in the valuation allowance would impact our income tax provision and net income in the period in which such a determination is made.

Please read Note 14 Income Taxes beginning on page F-48 for further discussion of our accounting for income taxes and any change in our valuation allowance.

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Valuation of Pension and Other Post-Retirement Plans Assets and Liabilities

Our pension and other post-retirement benefit costs are developed from actuarial valuations. Inherent in these valuations are key assumptions including the discount rate and expected long-term rate of return on plan assets. Material changes in our pension and other post-retirement benefit costs may occur in the future due to changes in these assumptions, changes in the number of plan participants and changes in the level of benefits provided.

The discount rate is subject to change each year, consistent with changes in applicable high-quality, long-term corporate bond indices. Long-term interest rates declined during 2005. Accordingly, at December 31, 2005, we used a discount rate of 5.52% for pension plans and 5.53% for other retirement plans, a decline of 23 and 22 basis points, respectively, from the 5.75% rate used as of December 31, 2004. This decline in the discount rate increased the underfunded status of the plans by $7 million.

Effective December 31, 2005, we changed to a yield curve approach for determining the discount rate. Projected benefit payments were matched against the discount rates in the Citigroup Pension Discount Curve to produce a weighted-average equivalent discount rate of 5.52% for the pension plans and 5.53% for the other post-retirement plans. In prior years, the discount rate we used was based on Moody s Aa Corporate Bond Rate. We changed our methodology because we feel the yield curve approach is a more accurate estimate of plan liabilities particularly due to the significant change in the composition of the participants in our pension and other retirement plans as a result of the sales of DMSLP and Illinois Power.

The expected long-term rate of return on pension plan assets is selected by taking into account the asset mix of the plans and the expected returns for each asset category. Based on these factors, our expected long-term rate of return as of January 1, 2006 is 8.25%, the same as 2005. We expect 2006 pension expense to be lower than 2005 pension expense by approximately $3 million, primarily due to the sale of DMSLP. The decrease will be partially offset by the discount rate discussed above and the passage of time.

On December 31, 2005, our annual measurement date, the accumulated benefit obligation related to our pension plans exceeded the fair value of the pension plan assets (such excess is referred to as an unfunded accumulated benefit obligation). In accordance with SFAS No. 87, Employers Accounting for Pensions, as of December 31, 2005, we have recognized a charge to accumulated other comprehensive loss of $8 million (net of taxes of $5 million), which decreases stockholders equity. The charge to stockholders equity for the excess of additional pension liability over the unrecognized prior service cost represents a net loss not yet recognized as pension expense.

A relatively small difference between actual results and assumptions used by management may have a material effect on our financial statements. Assumptions used by another party could be different than our assumptions. The following table summarizes the sensitivity of pension expense and our projected benefit obligation, or PBO, to changes in the discount rate and the expected long-term rate of return on pension assets:

	Impact on PBO, December 31, 2005	Impact on 2006 Expense

	(in millions)	
Increase in Discount Rate 50 basis points	$ (15.5)	$ (1.7)
Decrease in Discount Rate 50 basis points	17.3	1.8
Increase in Expected Long-term Rate of Return 50 basis points		(0.6)
Decrease in Expected Long-term Rate of Return 50 basis points		0.6

We expect to make $17 million in cash contributions related to our pension plans during 2006. In addition, it is likely that we will be required to continue to make contributions to the pension plans beyond 2006. Although it is difficult to estimate these potential future cash requirements due to uncertain market conditions, we currently expect that the cash requirements would be approximately $12 million in 2007 and $18 million in 2008.

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Please read Note 20 Employee Compensation, Savings and Pension Plans beginning on page F-71 for further discussion of our pension related assets and liabilities.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 2 Accounting Policies Accounting Principles Adopted beginning on page F-20 for a discussion of recently issued accounting pronouncements affecting us. Specifically, we adopted FIN No. 47 on December 31, 2005. We adopted EITF Issue 04-8, EITF Issue 02-14 and certain provisions of FIN No. 46R on January 1, 2004, and we adopted other portions of FIN No. 46R effective December 31, 2003. We adopted SFAS No. 150 and EITF Issue 03-11 effective July 1, 2003. We adopted FIN No. 45 and SFAS No. 143 effective January 1, 2003.

RISK-MANAGEMENT DISCLOSURES

The following table provides a reconciliation of the risk-management data on the consolidated balance sheets:

	As of and for the Year Ended December 31, 2005 (in millions)
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at January 1, 2005	$ (133)
Risk-management losses recognized through the income statement in the period, net	(23)
Cash paid related to risk-management contracts settled in the period, net	103
Changes in fair value as a result of a change in valuation technique (1)	
Non-cash adjustments and other (2)	(59)
Fair value of portfolio at December 31, 2005	$ (112)

(1) Our modeling methodology has been consistently applied.
(2) This amount consists of changes in value associated with cash flow hedges on forward power sales and fair value hedges on debt, which were partially offset by the $62 million risk-management asset acquired in connection with the Sithe Energies transaction.

The net risk-management liability of $112 million is the aggregate of the following line items on the consolidated balance sheets: Current Assets Assets from risk-management activities, Other Assets Assets from risk-management activities, Current Liabilities Liabilities from risk-management activities and Other Liabilities Liabilities from risk-management activities.

Risk-Management Asset and Liability Disclosures

The following table depicts the mark-to-market value and cash flow components, based on contract terms, of our net risk-management assets and liabilities at December 31, 2005. As opportunities arise to monetize positions that we believe will result in an economic benefit to us, we may receive or pay cash in periods other than those depicted below.

Net Risk-Management Asset and Liability Disclosures

	Total	2006	2007	2008	2009	2010	Thereafter
				(in millions)			
Mark-to-Market (1)(3)	$ (84)	$ (5)	$ (65)	$ (19)	$ 2	$	$ 3
Cash Flow (2)	(78)	1	(64)	(21)	2		4

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(1) Mark-to-market reflects the fair value of our risk-management asset position, which considers time value, credit, price and other reserves necessary to determine fair value. These amounts exclude the fair value associated with certain derivative instruments designated as hedges. The net risk-management liabilities at December 31, 2005 of $112 million on the consolidated balance sheets includes the $84 million herein as well as hedging instruments. Cash flows have been segregated between periods based on the delivery date required in the individual contracts.

(2) Cash flow reflects undiscounted cash inflows and outflows by contract based on the tenor of individual contract position for the remaining periods. These anticipated undiscounted cash flows have not been adjusted for counterparty credit or other reserves. These amounts exclude the cash flows associated with certain derivative instruments designated as hedges.

(3) Our mark-to-market values at December 31, 2005 were derived solely from market quotations instead of the combination of long-term valuation models and market quotations used in prior years. Following our Sithe Energies acquisition and the resulting restructuring of the Independence toll, we no longer use long-term valuation models, as our risk-management portfolio can be fully valued based on market quotations.

Derivative Contracts

The absolute notional contract amounts associated with our commodity risk-management, interest rate and foreign currency exchange contracts are discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 85.

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

We are exposed to commodity price variability related to our power generation business and legacy trading portfolio. In addition, fuel requirements at our power generation facilities represent additional commodity price risks to us. In order to manage these commodity price risks, we routinely utilize various fixed-price forward purchase and sales contracts, futures and option contracts traded on the New York Mercantile Exchange and swaps and options traded in the over-the-counter financial markets to:

- manage and hedge our fixed-price purchase and sales commitments;
- reduce our exposure to the volatility of cash market prices; and
- hedge our fuel requirements for our generating facilities.

The potential for changes in the market value of our commodity, interest rate and currency portfolios is referred to as market risk. A description of each market risk category is set forth below:

- Commodity price risks result from exposures to changes in spot prices, forward prices and volatilities in commodities, such as electricity, natural gas, coal, fuel oil, emissions and other similar products;
- Interest rate risks primarily result from exposures to changes in the level, slope and curvature of the yield curve and the volatility of interest rates; and
- Currency rate risks result from exposures to changes in spot prices, forward prices and volatilities in currency rates.

In the past, we have attempted to manage these market risks through diversification, controlling position sizes and executing hedging strategies. The ability to manage an exposure may, however, be limited by adverse changes in market liquidity, our credit capacity or other factors.

VaR. In addition to applying business judgment, senior management uses a number of quantitative tools to monitor our exposure to market risk. These tools include stress and scenario analyses performed periodically that measure the potential effects of various market events.

The modeling of the risk characteristics of our mark-to-market portfolio involves a number of assumptions and approximations. We estimate VaR using a JP Morgan RiskMetrics approach assuming a one-day holding period. Inputs for the VaR calculation are prices, positions, instrument valuations and the variance-covariance matrix. VaR does not account for liquidity risk or the potential that adverse market conditions may prevent liquidation of existing market positions in a timely fashion. While management believes that these assumptions and approximations are reasonable, there is no uniform industry methodology for estimating VaR, and different assumptions and/or approximations could produce materially different VaR estimates.

We use historical data to estimate our VaR and, to better reflect current asset and liability volatilities, this historical data is weighted to give greater importance to more recent observations. Given our reliance on historical data, VaR is effective in estimating risk exposures in markets in which there are not sudden fundamental changes or shifts in market conditions. An inherent limitation of VaR is that past changes in market risk factors, even when weighted toward more recent observations, may not produce accurate predictions of future market risk. VaR should be evaluated in light of this and the methodology s other limitations.

VaR represents the potential loss in value of our mark-to-market portfolio due to adverse market movements over a defined time horizon within a specified confidence level. For the VaR numbers reported below, a one-day time horizon and a 95% confidence level were used. This means that there is a one in 20 statistical chance that the daily portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR. Thus, a change in portfolio value greater than the expected change in portfolio value on a single trading day would be anticipated to occur, on average, about once a month. Gains or losses on a single day can exceed reported VaR by significant amounts. Gains or losses can also accumulate over a longer time horizon such as a number of consecutive trading days.

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In addition, we have provided our VaR using a one-day time horizon and a 99% confidence level. The purpose of this disclosure is to provide an indication of earnings volatility using a higher confidence level. Under this presentation, there is a one in 100 statistical chance that the daily portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR. We have also disclosed a two-year comparison of daily VaR in order to provide context for the one-day amounts.

The following table sets forth the aggregate daily VaR and average VaR of the mark-to-market portion of our generation business and legacy trading portfolios.

Daily and Average VaR for Mark-to-Market Portfolios

	December 31, 2005	December 31, 2004
	(in millions)	
One Day VaR 95% Confidence Level	$ 5	$ 5
One Day VaR 99% Confidence Level	$ 6	$ 7
Average VaR for the Year-to-Date Period 95% Confidence Level	$ 7	$ 4

Credit Risk. Credit risk represents the loss that we would incur if a counterparty fails to perform pursuant to the terms of its contractual obligations. To reduce our credit exposure, we execute agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to further reduce credit risk with certain counterparties by obtaining third party guarantees or collateral as well as the right of termination in the event of default.

Our Credit Department, based on guidelines approved by the Board of Directors, establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical delivery and financial contracts. Our credit risk system provides current credit exposure to counterparties on a daily basis.

The following table represents our credit exposure at December 31, 2005 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary

	Investment Grade Quality	Non-Investment Grade Quality	Total
		(in millions)	
Type of Business:			
Financial Institutions	$ 106	$	$ 106

Commercial/Industrial/End Users	50	29	79
Utility and Power Generators	133		133
Total	$ 289	$ 29	$ 318

Of the $29 million in credit exposure to non-investment grade counterparties, approximately 64% ($18 million) is collateralized or subject to other credit exposure protection.

Interest Rate Risk. Interest rate risk primarily results from variable rate debt obligations. Although changing interest rates impact the discounted value of future cash flows, and therefore the value of our risk management portfolios, the relative near-term nature and size of our risk management portfolios minimizes the impact. Management continues to monitor our exposure to fluctuations in interest rates and may execute swaps or other financial instruments to change our risk profile for this exposure.

We are exposed to fluctuating interest rates related to variable rate financial obligations. As of December 31, 2005, our fixed rate debt instruments as a percentage of total debt instruments was 87%. Based on

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sensitivity analysis of the variable rate financial obligations in our debt portfolio as of December 31, 2005, it is estimated that a one percentage point interest rate movement in the average market interest rates (either higher or lower) over the 12 months ended December 31, 2006 would either decrease or increase income before taxes by approximately $8 million. Hedging instruments that impact such interest rate exposure are included in the sensitivity analysis. Over time, we may seek to reduce the percentage of fixed rate financial obligations in our debt portfolio through the use of swaps or other financial instruments.

Foreign Currency Exchange Rate Risk. Foreign currency risk arises from our investments in affiliates and subsidiaries owned and operated in foreign countries. Such risk is also a result of risk management transactions with customers in countries outside the United States. Management monitors our exposure to fluctuations in foreign currency exchange rates. When possible, contracts are denominated in or indexed to the U.S. dollar.

At December 31, 2005, our primary foreign currency exchange rate exposures were the Canadian Dollar and European Euro. Additionally, as further discussed in Liquidity and Capital Resources Internal Liquidity Sources Current Liquidity beginning on page 55, at December 31, 2005, approximately $40 million cash denominated in the U.K. Pound, the Euro and the Canadian Dollar remains in the U.K. and Canada.

Derivative Contracts. The absolute notional financial contract amounts associated with our commodity risk-management and interest rate contracts accounted for on a mark-to-market basis were as follows at December 31, 2005 and December 31, 2004, respectively:

Absolute Notional Contract Amounts

	December 31, 2005	December 31, 2004
Natural Gas (Trillion Cubic Feet)	0.374	1.084
Electricity (Million Megawatt Hours) (1)	30.479	11.652
Emission Credits (Million Tons) (2)	0.043	0.119
Fair Value Hedge Interest Rate Swaps (In Millions of U.S. Dollars)	$ 525	$ 525
Fixed Interest Rate Received on Swaps (%)	4.331	4.331
Interest Rate Risk-Management Contract (In Millions of U.S. Dollars)	$ 25	$ 25
Fixed Interest Rate Paid (%)	5.998	5.998

(1) At December 31, 2005, this amount includes notional volumes related to Financial Transmission Rights (FTRs) that we acquired in various ISOs during 2005.

(2) These amounts represent emission credit contracts that we are required to account for as derivatives under SFAS No. 133. These amounts do not include the emission credits that we have recorded in our inventory related to allowances that we utilize in running our power generation fleet

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

Our financial statements and financial statement schedules are set forth at pages F-1 through F-107 inclusive, found at the end of this annual report, and are incorporated herein by reference.

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

Not applicable.

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

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of our management, including our

Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified by the SEC. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002, which is further described below.

Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2005, as a result of the material weakness discussed below, our disclosure controls and procedures were not effective to ensure that the information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the requisite time periods and that such information is accumulated and communicated to management, including our CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure. Due to the material weakness discussed below, in preparing our financial statements at and for the year ended December 31, 2005, we performed additional procedures relating to the income tax provision in an attempt to ensure that such financial statements were fairly presented in all material respects in accordance with generally accepted accounting principles.

Management s Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including the CEO and CFO, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2005. In making this assessment, we used the criteria set forth in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements would not be prevented or detected. As of December 31, 2005, we did not maintain effective controls over the completeness and accuracy of the tax provision and deferred income tax balances in accordance with generally accepted accounting principles. Specifically, our processes, procedures and controls related to the preparation, analysis and recording of the income tax provision were not effective to ensure that the deferred tax provision and deferred tax balances were recorded in accordance with generally accepted accounting principles. This control deficiency resulted in the restatement of our 2004 and 2003 annual consolidated financial statements, as well as audit adjustments to the 2005 income tax provision. Further, this control deficiency could result in a misstatement of the income tax provision and related deferred tax accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Therefore, we have concluded that this control deficiency constitutes a material weakness.

Because of the material weakness described above management has concluded that, as of December 31, 2005, we did not maintain effective internal control over our financial reporting based on the criteria set forth in *Internal Control Integrated Framework* issued by the COSO.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which appears on page F-2.

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Changes in Internal Control over Financial Reporting. We made no changes in our internal control over financial reporting during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act).

Remediation of Material Weakness. We previously reported in our 2004 Form 10-K that we did not maintain effective internal control over financial reporting as of December 31, 2004 due to the same material weakness discussed above. During 2005, actions were taken to remediate the material weakness reported in our 2004 Form 10-K, including: (i) increased levels of review in the preparation of the quarterly and annual tax provisions; (ii) formalized processes, procedures and documentation standards relating to the income tax provision; and (iii) restructured our Tax Department to ensure appropriate segregation of duties regarding preparation and review of the quarterly and annual tax provision. Despite these efforts, when making management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, we determined that those controls were still not operating effectively.

In addition to continuing the enhanced processes implemented in 2004 and 2005 and described above, during 2006, we plan to take the following steps in an attempt to remediate the material weakness as of December 31, 2005: (i) implement new processes around the analysis of the income tax provision, including detailed reconciliations between book basis and tax basis of significant tax sensitive balance sheet accounts; (ii) implement additional procedures around the identification, analysis and recording of the tax effects of significant transactions; and (iii) further formalize and document the procedures around the preparation and review of the tax provision and tax accounts. We will not be able to conclude that the material weakness has been successfully remediated, and we cannot assure you we will be able to make such conclusion, until the testing of controls demonstrates that such controls have operated effectively for a sufficient period of time.

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

Not applicable.

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PART III

Item 10. *Directors and Executive Officers of the Registrant*

Executive Officers

Set forth below are the names and positions of our executive officers as of March 1, 2006, together with their ages and years of service with us.

Name	Age	Position(s)	Served With the Company Since
Bruce A. Williamson	45	Chief Executive Officer and Chairman of the Board	2002
Stephen A. Furbacher	58	President and Chief Operating Officer	1996
Holli C. Nichols	35	Executive Vice President and Chief Financial Officer	2000
J. Kevin Blodgett	34	General Counsel and Executive Vice President, Administration	2000
Lynn A. Lednicky	45	Executive Vice President of Strategic Planning and Corporate Business Development	1991

The executive officers named above will serve in such capacities until the next annual meeting of our Board of Directors, or until their respective successors have been duly elected and have been qualified, or until their earlier death, resignation, disqualification or removal from office.

Bruce A. Williamson has served as CEO and as a director of Dynegy since October 2002 and as Chairman of the Board of Dynegy since May 2004. Prior to joining Dynegy, Mr. Williamson served in various capacities with Duke Energy and its affiliates, most recently serving as President and Chief Executive Officer of Duke Energy Global Markets. In this capacity, he was responsible for all Duke Energy business units with global commodities and international business positions. Mr. Williamson joined PanEnergy Corporation in June 1995, which then merged with Duke Power in June 1997. Prior to the Duke-PanEnergy merger, he served as PanEnergy s Vice President of Finance. Before joining PanEnergy, he held positions of increasing responsibility at Shell Oil Company, advancing over a 14-year period to Assistant Treasurer.

Stephen A. Furbacher has served as President and Chief Operating Officer since August 2005 and as Executive Vice President of the NGL segment from September 1996 to August 2005. Mr. Furbacher is responsible for overseeing Power Generation and, until October 31, 2005, the Midstream operations. He joined us in May 1996, just prior to our acquisition of Chevron s midstream business. Before joining us, he served as President of Warren Petroleum Company, the natural gas liquids division of Chevron U.S.A. He began his career with Chevron in August 1973 and served in positions of increasing responsibility before being named President of Warren Petroleum Company in July 1994.

Holli C. Nichols has served as Executive Vice President and Chief Financial Officer since November 2005. Ms. Nichols is responsible for our financial affairs, including finance and accounting, treasury, risk management, internal audit and investor and credit agency relationships. Ms. Nichols previously served as Senior Vice President and Treasurer since May 2004 and served as our Senior Vice President and Controller from June 2003 to May 2004. Ms. Nichols joined Dynegy from PricewaterhouseCoopers LLP in May 2000.

J. Kevin Blodgett has served as General Counsel and Executive Vice President, Administration since November 2005. Mr. Blodgett is responsible for our legal and administrative affairs, including legal services supporting our operational, commercial and corporate areas, as well as ethics and compliance, human resources, information technology, building services, real estate and procurement management. Mr. Blodgett previously served as Senior Vice President, Human Resources from August 2004 to November 2005 and served as Group General Counsel Corporate Finance & Securities and Corporate Secretary from May 2003 to August 2004. Mr. Blodgett joined Dynegy from Baker Botts LLP in October 2000.

Lynn A. Lednicky has served as Executive Vice President of Strategic Planning and Corporate Business Development since November 2005 and as Senior Vice President of Strategic Planning and Corporate Business Development since July 2003. Mr. Lednicky is responsible for identifying opportunities and strategies for building value at both the corporate level and within our power generation business. In addition, Mr. Lednicky has previously served as Senior Vice President of Power Origination from December 2000 to July 2003. Mr. Lednicky joined Dynegy s predecessor Destec Energy, Inc. in July 1991.

Code of Ethics. We have adopted a Code of Ethics within the meaning of Item 406(b) of Regulation S-K. This Code of Ethics applies to our chief executive officer, chief financial officer, controller and other persons performing similar functions designated by the chief financial officer, and is incorporated as an exhibit to this Form 10-K.

Other Information. The other information required by this Item 10 will be contained in our definitive proxy statement for our 2006 annual meeting of shareholders under the headings Proposal 1 Election of Directors and Executive Compensation Section 16(a) Beneficial Ownership Reporting Compliance and is incorporated herein by reference. The proxy statement will be filed with the SEC not later than 120 days after December 31, 2005.

Item 11. *Executive Compensation*

Information with respect to executive compensation will be contained in the upcoming proxy statement under the heading Executive Compensation and is incorporated herein by reference.

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

Information regarding ownership of our outstanding securities will be contained in the upcoming proxy statement under the heading Principal Shareholders and is incorporated herein by reference.

Item 13. *Certain Relationships and Related Transactions*

Information regarding related party transactions will be contained in the upcoming proxy statement under the headings Principal Stockholders, Proposal 1 Election of Directors and Executive Compensation Employment Agreements and Change-in-Control Agreements and Certain Relationships and Related Transactions and is incorporated herein by reference.

Item 14. *Principal Accountant Fees and Services*

Information regarding principal accountant fees and services will be contained in the upcoming proxy statement under the heading Independent Auditors and is incorporated herein by reference.

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PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) The following documents, which we have filed with the SEC pursuant to the Securities Exchange Act of 1934, as amended, are by this reference incorporated in and made a part of this annual report:

1. Financial Statements Our consolidated financial statements are incorporated under Item 8. of this annual report.

2. Financial Statement Schedules Financial Statement Schedules are incorporated under Item 8. of this annual report.

3. Exhibits The following instruments and documents are included as exhibits to this annual report. All management contracts or compensation plans or arrangements set forth in such list are marked with a .

Exhibit Number	Description
2.1	Purchase Agreement dated February 2, 2004 among Dynegy Inc., Illinova Corporation, Illinova Generating Company and Ameren Corporation (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 4, 2004, File No. 1-15659).
3.1	Amended and Restated Articles of Incorporation of Dynegy Inc. (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 25, 2001).
3.2	Statement of Resolution Establishing Series of Series C Convertible Preferred Stock of Dynegy Inc. (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
3.3	Amended and Restated Bylaws of Dynegy Inc. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on November 21, 2005, File No. 1-15659).
4.1	Indenture, dated as of December 11, 1995, by and among NGC Corporation, the Subsidiary Guarantors named therein and the First National Bank of Chicago, as Trustee (incorporated by reference to exhibits to the Registration Statement on Form S-3 of NGC Corporation, Registration No. 33-97368).
4.2	First Supplemental Indenture, dated as of August 31, 1996, by and among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156).
4.3	Second Supplemental Indenture, dated as of October 11, 1996, by and among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156).
4.4	

Fourth Supplemental Indenture among NGC Corporation, Destec Energy, Inc. and The First National Bank of Chicago, as Trustee, dated as of June 30, 1997, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.12 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1997 of NGC Corporation, File No. 1-11156).

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Exhibit Number	Description
4.5	Fifth Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of September 30, 1997, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.18 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.6	Sixth Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of January 5, 1998, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.19 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.7	Seventh Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of February 20, 1998, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.20 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156).
4.8	Eighth Supplemental Indenture dated July 25, 2003 that certain Indenture, dated as of December 11, 1995, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659).
4.9	Subordinated Debenture Indenture between NGC Corporation and The First National Bank of Chicago, as Debenture Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.10	Amended and Restated Declaration of Trust among NGC Corporation, Wilmington Trust Company, as Property Trustee and Delaware Trustee, and the Administrative Trustees named therein, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.11	Series A Capital Securities Guarantee Agreement executed by NGC Corporation and The First National Bank of Chicago, as Guarantee Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.12	Common Securities Guarantee Agreement of NGC Corporation dated as of May 28, 1997 (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.13	Registration Rights Agreement, dated as of May 28, 1997, among NGC Corporation, NGC Corporation Capital Trust I, Lehman Brothers, Salomon Brothers Inc. and Smith Barney Inc. (incorporated by reference to Exhibit 4.11 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.14	Indenture, dated as of September 26, 1996, restated as of March 23, 1998, and amended and restated as of March 14, 2001, between Dynegy Holdings Inc. and Bank One Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2000 of Dynegy Holdings Inc., File No. 0-29311).

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4.15	First Supplemental Indenture dated July 25, 2003 to that certain Indenture, dated as of September 26, 1996, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659).
4.16	Exchange and Registration Rights Agreement (Preferred Stock) dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.17	Amended and Restated Registration Rights Agreement (Common Stock) dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.18	Amended and Restated Shareholder Agreement dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.19	Indenture dated as of August 11, 2003 among Dynegy Holdings Inc., the guarantors named therein, Wilmington Trust Company, as trustee, and Wells Fargo Bank Minnesota, N.A., as collateral trustee, including the form of promissory note for each series of notes issuable pursuant to the Indenture (incorporated by reference to Exhibit 4.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.20	Indenture dated August 11, 2003 between Dynegy Inc., Dynegy Holdings Inc. and Wilmington Trust Company, as trustee, including the form of debenture issuable pursuant to the Indenture (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.21	Registration Rights Agreement dated August 11, 2003 among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
4.22	Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
4.23	First Supplemental Indenture dated as of January 1, 1993 to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.23 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
4.24	Second Supplemental Indenture dated as of October 23, 2001 to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.24 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
4.25	Global Note representing the 8.50% Secured Bonds due 2007 of Sithe/Independence Power Partners, L.P. (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).

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4.26	Global Note representing the 9.00% Secured Bonds due 2013 of Sithe/Independence Power Partners, L.P. (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).
	There have not been filed or incorporated as exhibits to this annual report, other debt instruments defining the rights of holders of our long-term debt, none of which relates to authorized indebtedness that exceeds 10% of our consolidated assets. We hereby agree to furnish a copy of any such instrument not previously filed to the SEC upon request.
10.1	Dynegy Inc. Amended and Restated 1991 Stock Option Plan (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156).
10.2	Dynegy Inc. 1998 U.K. Stock Option Plan (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156).
10.3	Dynegy Inc. Amended and Restated Employee Equity Option Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156).
10.4	Dynegy Inc. 1999 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156).
10.5	Dynegy Inc. 2000 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156).
10.6	Dynegy Inc. 2001 Non-Executive Stock Incentive Plan (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.7	Dynegy Inc. 2002 Long Term Incentive Plan (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 9, 2002).
10.8	Extant, Inc. Equity Compensation Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-47422).
10.9	Employment Agreement, dated October 18, 2002, between Bruce A. Williamson and Dynegy Inc. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2002 of Dynegy Inc., File No. 1-15659).
10.10	First Amendment to October 18, 2002 Employment Agreement dated August 17, 2005 between Bruce A. Williamson and Dynegy Inc. (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.11	Second Amendment to October 18, 2002 Employment Agreement dated September 15, 2005 between Bruce A. Williamson and Dynegy Inc. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2005, File No. 1-15659).
10.12	Contract for Consulting Services dated March 19, 2004 between Dynegy Inc. and Daniel L. Dienstbier (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2004 of Dynegy Inc., File No. 1-15659).
10.13	Severance Agreement and Release dated December 31, 2005 between Dynegy Inc. and Carol F. Graebner (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 6, 2006, File No. 1-15659).

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10.14	Severance Agreement and Release dated December 31, 2005 between Dynegy Inc. and R. Blake Young (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on January 6, 2006, File No. 1-15659).
10.15	Dynegy Inc. 401(k) Savings Plan, as amended and restated effective January 1, 2002 (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 383-76570).
10.16	First Amendment to the Dynegy Inc. 401(k) Savings Plan, effective February 11, 2002 (incorporated by reference to Exhibit 10.19 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.17	Second Amendment to the Dynegy Inc. 401(k) Savings Plan, effective January 1, 2002 (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.18	Third Amendment to the Dynegy Inc. 401(k) Savings Plan, effective October 1, 2003 (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.19	Amendment to the Dynegy Inc. 401(k) Savings Plan, effective January 1, 2004 (incorporated by reference to Exhibit 10.18 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.20	Dynegy Inc. 401(k) Savings Plan Trust Agreement (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76570).
10.21	Dynegy Inc. Deferred Compensation Plan (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.22	Dynegy Inc. Deferred Compensation Plan Trust Agreement (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.23	Dynegy Inc. Short-Term Executive Stock Purchase Loan Program (incorporated by reference to Exhibit 10.19 to the Annual Report on Form 10-K for the Year Ended December 31, 2001 of Dynegy Inc., File No. 1-15659).
10.24	Dynegy Inc. Deferred Compensation Plan for Certain Directors (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.25	First Amendment to the Dynegy Inc. Deferred Compensation Plan for Certain Directors dated September 15, 2005 (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2005, File No. 1-15659).
10.26	Second Amendment to the Dynegy Inc. Deferred Compensation Plan for Certain Directors dated December 16, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 22, 2005, File No. 1-15659).
10.27	Dynegy Inc. Executive Severance Pay Plan as amended and restated effective as of February 1, 2005 (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659).
10.28	First Amendment to the Dynegy Inc. Executive Severance Pay Plan dated September 15, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2005, File No. 1-15659).

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10.29	Second Amendment to the Dynegy Inc. Executive Severance Pay Plan dated October 31, 2005 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659).
10.30	Second Supplement to the Dynegy Inc. Executive Severance Pay Plan dated November 20, 2003 (incorporated by reference to Exhibit 99.4 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659).
10.31	First Amendment to the Second Supplement to the Dynegy Inc. Executive Severance Pay Plan dated June 22, 2005 (incorporated by reference to Exhibit 99.5 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659).
10.32	Second Amendment to the Second Supplement to the Dynegy Inc. Executive Severance Pay Plan dated September 15, 2005 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2005, File No. 1-15659).
10.33	Third Amendment to the Second Supplement to the Dynegy Inc. Executive Severance Pay Plan dated October 31, 2005 (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659).
10.34	Dynegy Inc. Mid-Term Incentive Performance Award Program (incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
**10.35	Termination of the Dynegy Inc. Mid-Term Incentive Performance Award Program effective January 1, 2006.
**10.36	Dynegy Inc. Incentive Compensation Plan, as amended and restated effective January 1, 2006.
10.37	Dynegy Northeast Generation, Inc. Savings Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-111985).
10.38	Amendment to the Dynegy Northeast Generation, Inc. Savings Incentive Plan, effective January 1, 2004 (incorporated by reference to Exhibit 10.31 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659).
10.39	Dynegy Inc. Severance Pay Plan, as amended and restated effective February 1, 2005 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659).
10.40	First Amendment to the Dynegy Inc. Severance Pay Plan dated October 31, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659).
**10.41	Second Amendment to the Dynegy Inc. Severance Pay Plan dated December 14, 2005.
10.42	First Supplemental Plan to the Dynegy Inc. Severance Pay Plan dated June 22, 2005 (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on June 28, 2005, File No. 1-15659).
10.43	First Amendment to the First Supplemental Plan to the Dynegy Inc. Severance Pay Plan dated October 31, 2005 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659).
10.44	Lease Agreement entered into on June 12, 1996 between Metropolitan Life Insurance Company and Metropolitan Tower Realty Company, Inc., as landlord, and NGC Corporation, as tenant (incorporated by reference to Exhibit 10.69 to the Registration Statement on Form S-4 of Midstream Combination Corp., Registration No. 333-09419).

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10.45	First Amendment to Lease Agreement entered into on June 12, 1996 between Metropolitan Life Insurance Company and Metropolitan Tower Realty Company, Inc., as landlord, and NGC Corporation, as tenant (incorporated by reference to Exhibit 10.70 to the Registration Statement on Form S-4 of Midstream Combination Corp., Registration No. 333-09419).
10.46	Amended and Restated Credit Agreement dated as of May 28, 2004 among Dynegy Holdings Inc., as Borrower, Dynegy Inc., as Parent Guarantor, the Other Guarantors Party Thereto, the Lenders Party Thereto and Various Other Parties Thereto (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 1, 2004, File No. 1-15659).
10.47	Second Amended and Restated Credit Agreement dated as of October 31, 2005 among Dynegy Holdings Inc., as Borrower, and Dynegy Inc., as Parent Guarantor (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on November 4, 2005, File No. 1-15659).
10.48	Third Amended and Restated Credit Agreement dated as of March 6, 2006 among Dynegy Holdings Inc., as Borrower, and Dynegy Inc., as Parent Guarantor (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 9, 2006, File No. 1-15659).
10.49	Shared Security Agreement, dated April 1, 2003, among Dynegy Holdings, Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.32 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.50	Non-Shared Security Agreement, dated April 1, 2003, among Dynegy Inc., various grantors named therein and Bank One, N.A. as collateral agent (incorporated by reference to Exhibit 10.33 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.51	Collateral Trust and Intercreditor Agreement, dated as of April 1, 2003, among Dynegy Holdings Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.34 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.52	Amendment No. 1 to Collateral Trust and Intercreditor Agreement, dated as of May 28, 2004, among Dynegy Holdings Inc., various grantors named therein, JPMorgan Chase Bank, as collateral agent, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2004 of Dynegy Inc., File No. 1-15659).
10.53	Series B Preferred Stock Exchange Agreement dated as of July 28, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.54	Indemnity Agreement dated August 11, 2003 among Dynegy Inc., Dynegy Holdings Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.55	Intercreditor Agreement dated August 11, 2003 among Dynegy Holdings Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, John M. Beeson, Jr., as individual trustee, Bank One, NA, as collateral agent, and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).

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10.56	Second Lien Shared Security Agreement dated August 11, 2003 among Dynegy Holdings Inc., various grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.57	Second Lien Non-Shared Security Agreement dated August 11, 2003 among Dynegy Inc., various grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.58	Purchase Agreement dated August 1, 2003 among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.59	Purchase Agreement dated August 1, 2003 among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.60	Purchase Agreement dated September 30, 2003 among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 15, 2003, File No. 1-15659).
10.61	Power Purchase Agreement dated September 30, 2004 between Illinois Power Company and Dynegy Power Marketing, Inc. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2004 of Dynegy Inc., File No. 1-15659).
10.62	Escrow Agreement dated as of September 30, 2004 among Illinova Corporation, Ameren Corporation and JPMorgan Chase Bank, as escrow agent (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2004 of Dynegy Inc., File No. 1-15659).
10.63	Stock Purchase Agreement dated as of November 1, 2004 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.48 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659)
10.64	Amendment to Stock Purchase Agreement (Special Payroll Payment) dated as of January 28, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659)
10.65	Amendment to Stock Purchase Agreement dated as of January 31, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659)
10.66	Amendment to Stock Purchase Agreement (Luz Sale) dated as of January 31, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659)
10.67	Tenth Amendment to Amended and Restated Base Gas Sales Agreement, dated as of June 29, 2001, by and between Enron North America Corp. and Sithe/Independence Power Partners, L.P. (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659)
10.68	Power Purchase Agreement dated November 17, 2004 between Dynegy Power Marketing, Inc. as seller, and Constellation Energy Commodities Group, Inc., as purchaser. (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659)

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10.69	Assignment and Assumption Agreement dated as of November 17, 2004 between Dynegy Power Marketing, Inc. and Constellation Energy Commodities Group, Inc. (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659)
10.70	Partnership Interest Purchase Agreement dated as of August 2, 2005 among Dynegy Inc, Dynegy Holdings Inc., Dynegy Midstream Holdings, Inc., and Dynegy Midstream G.P., Inc. as Sellers and Targa Resources, Inc., Targa Resources Partners OLP LP, and Targa Midstream GP, LLC as Buyers (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.71	Steam and Electric Power Sales Agreement dated as of September 6, 2005 between Cogen Lyondell, Inc. and Lyondell Chemical Company (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.72	Services Agreement for CLI Facility dated as of September 6, 2005 between Cogen Lyondell, Inc. and Lyondell Chemical Company (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.73	Amended and Restated Lease and Easement Agreement dated as of September 6, 2005 between Cogen Lyondell, Inc. and Lyondell Chemical Company (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.74	Guaranty Agreement dated as of September 6, 2005 by Dynegy Holdings Inc. on behalf of Cogen Lyondell, Inc. in favor of Lyondell Chemical Company (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2005 of Dynegy Inc., File No. 1-15659).
10.75	Termination Agreement and Release dated as of December 23, 2005 between Quachita Power, LLC and Dynegy Power Marketing, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 28, 2005, File No. 1-15659).
10.76	Purchase Agreement (Rocky Road Power) dated December 27, 2005 between NRG Rocky Road LLC, NRG Energy, Inc., Termo Santander Holding, L.L.C. and Dynegy Inc. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on December 28, 2005, File No. 1-15659).
10.77	Purchase Agreement (West Coast Power) dated December 27, 2005 between NRG West Coast LLC, NRG Energy, Inc., DPC II Inc. and Dynegy Inc. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on December 28, 2005, File No. 1-15659).
10.78	Stipulation of Settlement dated May 2, 2005 (Shareholder Class Action Litigation) (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).
10.79	Stipulation of Settlement dated April 29, 2005 (Shareholder Derivative Litigation) (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).
10.80	Baldwin Consent Decree approved May 27, 2005 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 31, 2005, File No. 1-15659).
10.81	Director Compensation Summary (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 24, 2005, File No. 1-15659).

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14.1	Dynegy Inc. Code of Ethics for Senior Financial Professionals (incorporated by reference to Exhibit 14.1 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1- 15659).
**21.1	Subsidiaries of the Registrant.
**23.1	Consent of PricewaterhouseCoopers LLP.
**23.2	Consent of PricewaterhouseCoopers LLP (West Coast Power LLC).
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

** Filed herewith

Pursuant to Securities and Exchange Commission Release No. 33-8238, this certification will be treated as accompanying this report and not filed as part of such report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or the Exchange Act, or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act.

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SIGNATURES

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

DYNEGY INC.

Date: March 14, 2006

By: /s/ Bruce A. Williamson

Bruce A. Williamson

Chief Executive Officer and

Chairman of the Board

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

/s/ Bruce A. Williamson **Bruce A. Williamson**	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 14, 2006
/s/ Stephen A. Furbacher **Stephen A. Furbacher**	President and Chief Operating Officer	March 14, 2006
/s/ Holli C. Nichols **Holli C. Nichols**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 14, 2006
/s/ Carolyn J. Stone **Carolyn J. Stone**	Senior Vice President and Controller (Principal Accounting Officer)	March 14, 2006
/s/ Charles E. Bayless **Charles E. Bayless**	Director	March 14, 2006
/s/ David W. Biegler **David W. Biegler**	Director	March 14, 2006
/s/ Linda W. Bynoe **Linda W. Bynoe**	Director	March 14, 2006

/s/ THOMAS D. CLARK, JR.	Director	March 14, 2006
Thomas D. Clark, Jr.		
/s/ BARRY J. GALT	Director	March 14, 2006
Barry J. Galt		
/s/ PATRICIA A. HAMMICK	Director	March 14, 2006
Patricia A. Hammick		
/s/ GEORGE L. MAZANEC	Director	March 14, 2006
George L. Mazanec		
/s/ ROBERT C. OELKERS	Director	March 14, 2006
Robert C. Oelkers		

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/s/ Rebecca B. Roberts **Rebecca B. Roberts**	Director	March 14, 2006
/s/ Howard B. Sheppard **Howard B. Sheppard**	Director	March 14, 2006
/s/ Joe J. Stewart **Joe J. Stewart**	Director	March 14, 2006
/s/ William L. Trubeck **William L. Trubeck**	Director	March 14, 2006

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DYNEGY INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

* West Coast Power s consolidated financial statements are included herein pursuant to Rule 3-09 of Regulation S-X.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Dynegy Inc:

We have completed integrated audits of Dynegy Inc. s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedules

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Dynegy Inc. and its subsidiaries at December 31, 2005 and December 31, 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the Explanatory Note, the 2004 and 2003 consolidated financial statements have been restated.

As discussed in Note 17, the Company is the subject of substantial litigation. The Company s ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, Accounting for Contingencies, that might result from the ultimate resolution of such matters.

As discussed in Note 2, the Company adopted the provisions of Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, and Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, as of December 31, 2005. As discussed in Note 2, the Company adopted the provisions of Emerging Issues Task Force Issue No. 04-8, The Effect of Contingently Convertible Instruments on Diluted Earnings per Share, as of January 1, 2004. As discussed in Note 2, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2003. As discussed in Note 2, the Company adopted the net presentation provisions of Emerging Issues Task Force Issue No. 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, as of January 1, 2002 and the provision related to the rescission of Emerging Issues Task Force Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, as of January 1, 2003. As discussed in Note 2, the Company adopted Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation, using the prospective method of transition prescribed by Statement of Financial Accounting

Standards No. 148, Accounting for Stock-Based Compensation - Transition and Disclosure, as of January 1, 2003.

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Internal control over financial reporting

Also, we have audited management s assessment, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A, that Dynegy Inc. did not maintain effective internal control over financial reporting as of December 31, 2005, because the Company did not maintain effective controls over the completeness and accuracy of the tax provision and deferred income tax balances in accordance with generally accepted accounting principles, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management s assessment. As of December 31, 2005, the Company did not maintain effective controls over the completeness and accuracy of the tax provision and deferred income tax balances in accordance with generally accepted accounting principles. Specifically, the Company s processes, procedures and controls related to the preparation, analysis and recording of the income tax provision were not effective to ensure that the deferred tax provision and deferred tax balances were recorded in accordance with generally accepted accounting principles. This control deficiency resulted in the restatement of the Company s 2004 and 2003 annual consolidated financial statements as well as audit adjustments to the 2005 income tax provision. Further, this control deficiency could result in a misstatement of the income tax provision and related deferred tax accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Therefore, the Company concluded that this control deficiency constitutes a material weakness. This material weakness was considered in determining the nature, timing, and extent of audit tests

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applied in our audit of the 2005 consolidated financial statements, and our opinion regarding the effectiveness of the Company s internal control over financial reporting does not affect our opinion on those consolidated financial statements.

In our opinion, management s assessment that Dynegy Inc. did not maintain effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. Also, in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Dynegy Inc. has not maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the COSO.

PricewaterhouseCoopers LLP

Houston, Texas

March 14, 2006

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DYNEGY INC.

CONSOLIDATED BALANCE SHEETS

See Explanatory Note

(in millions, except share data)

	December 31, 2005	December 31, 2004
		(Restated)
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,549	$ 628
Restricted cash	397	
Accounts receivable, net of allowance for doubtful accounts of $103 and $159, respectively	611	810
Accounts receivable, affiliates	29	14
Inventory	214	221
Assets from risk-management activities	665	565
Deferred income taxes	14	62
Prepayments and other current assets	227	428
Total Current Assets	3,706	2,728
Property, Plant and Equipment	6,515	7,822
Accumulated depreciation	(1,192)	(1,692)
Property, Plant and Equipment, Net	5,323	6,130
Other Assets		
Unconsolidated investments	270	421
Restricted investments	85	
Assets from risk-management activities	165	313
Goodwill		15
Intangible assets	392	
Deferred income taxes	3	15
Other long-term assets	182	221
Total Assets	$ 10,126	$ 9,843
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 504	$ 557
Accounts payable, affiliates	46	23
Accrued interest	159	118
Accrued liabilities and other current liabilities	649	454
Liabilities from risk-management activities	687	616
Notes payable and current portion of long-term debt	71	34
Total Current Liabilities	2,116	1,802
Long-term debt	4,028	4,132

Long-term debt to affiliates	200	200
Long-Term Debt	4,228	4,332
Other Liabilities		
Liabilities from risk-management activities	255	395
Deferred income taxes	545	499
Other long-term liabilities	429	353
Total Liabilities	7,573	7,381
Minority Interest		106
Commitments and Contingencies (Note 17)		
Redeemable Preferred Securities, redemption value of $400 at December 31, 2005 and December 31, 2004 (Note 15)	400	400
Stockholders Equity		
Class A Common Stock, no par value, 900,000,000 shares authorized at December 31, 2005 and December 31, 2004; 305,129,052 and 285,012,203 shares issued and outstanding at December 31, 2005 and December 31, 2004, respectively	2,949	2,859
Class B Common Stock, no par value, 360,000,000 shares authorized at December 31, 2005 and December 31, 2004; 96,891,014 shares issued and outstanding at December 31, 2005 and December 31, 2004	1,006	1,006
Additional paid-in capital	51	41
Subscriptions receivable	(8)	(8)
Accumulated other comprehensive income (loss), net of tax	4	(13)
Accumulated deficit	(1,780)	(1,861)
Treasury stock, at cost, 1,714,026 and 1,679,183 shares at December 31, 2005 and December 31, 2004, respectively	(69)	(68)
Total Stockholders Equity	2,153	1,956
Total Liabilities and Stockholders Equity	$ 10,126	$ 9,843

See the notes to the consolidated financial statements.

DYNEGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Year Ended December 31,		
	2005	**2004**	**2003**
Revenues	$ 2,313	$ 2,451	$ 2,599
Cost of sales, exclusive of depreciation shown separately below	(2,416)	(1,850)	(2,150)
Depreciation and amortization expense	(220)	(235)	(373)
Goodwill impairment			(311)
Impairment and other charges	(46)	(78)	(225)
Gain (loss) on sale of assets, net	(1)	(58)	6
General and administrative expenses	(468)	(330)	(315)
Operating loss	(838)	(100)	(769)
Earnings from unconsolidated investments	2	192	126
Interest expense	(389)	(453)	(503)
Other income and expense, net	26	12	25
Minority interest income (expense)		(3)	20
Accumulated distributions associated with trust preferred securities			(8)
Loss from continuing operations before income taxes	(1,199)	(352)	(1,109)
Income tax benefit	395	172	296
Loss from continuing operations	(804)	(180)	(813)
Income from discontinued operations, net of tax expense of $344, $111 and $41, respectively (Note 4)	912	165	81
Income (loss) before cumulative effect of change in accounting principles	108	(15)	(732)
Cumulative effect of change in accounting principles, net of tax benefit (expense) of $2, zero and $(24), respectively (Note 2)	(5)		40
Net income (loss)	103	(15)	(692)
Less: preferred stock dividends (gain) (Note 13)	22	22	(1,013)
Net income (loss) applicable to common stockholders	$ 81	$ (37)	$ 321
Earnings (Loss) Per Share (Note 16):			
Basic earnings (loss) per share:			
Earnings (loss) from continuing operations	$ (2.13)	$ (0.53)	$ 0.53
Income from discontinued operations	2.35	0.43	0.22
Cumulative effect of change in accounting principles	(0.01)		0.11
Basic earnings (loss) per share	$ 0.21	$ (0.10)	$ 0.86

Diluted earnings (loss) per share:			
Earnings (loss) from continuing operations	$ (2.13)	$ (0.53)	$ 0.50
Income from discontinued operations	2.35	0.43	0.19
Cumulative effect of change in accounting principles	(0.01)		0.09
Diluted earnings (loss) per share	$ 0.21	$ (0.10)	$ 0.78
Basic shares outstanding	387	378	374
Diluted shares outstanding	513	504	423

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31,		
	2005	**2004**	**2003**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 103	$ (15)	$ (692)
Adjustments to reconcile income (loss) to net cash flows from operating activities:			
Depreciation and amortization	284	356	525
Goodwill impairment			311
Impairment and other charges	46	83	225
(Earnings) losses from unconsolidated investments, net of cash distributions	73	(66)	33
Risk-management activities	46	(50)	382
(Gain) loss on sale of assets, net	(1,096)	(11)	(57)
Deferred taxes	(86)	(74)	(258)
Cumulative effect of change in accounting principles (Note 2)	5		(40)
Reserve for doubtful accounts	1		19
Liability associated with gas transportation contracts (Note 4)		(148)	
Independence toll settlement charge (Note 3)	169		
Legal and settlement charges	119	104	58
Sterlington toll settlement charge (Note 4)	364		
Other	22	(40)	(67)
Changes in working capital:			
Accounts receivable	(134)	4	1,683
Inventory	(91)	(36)	93
Prepayments and other assets	148	(107)	726
Accounts payable and accrued liabilities	(2)	(13)	(2,017)
Changes in non-current assets	(15)	(22)	(24)
Changes in non-current liabilities	14	40	(24)
Net cash provided by (used in) operating activities	(30)	5	876
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(195)	(311)	(333)
Investments in unconsolidated affiliates			(5)
Business acquisitions, net of cash acquired	(120)	(3)	
Increase in restricted cash	(353)		
Proceeds from asset sales, net	2,488	576	72
Other investing, net	4		
Net cash provided by (used in) investing activities	1,824	262	(266)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	600	581	2,219

Repayments of borrowings	(1,432)	(650)	(2,749)
Net cash flow from commercial paper and revolving lines of credit			(128)
Payment to Chevron for Series B preferred stock restructuring			(225)
Proceeds from issuance of capital stock	2	5	6
Dividends and other distributions, net	(22)	(22)	
Other financing, net	(21)	(29)	(23)
Net cash used in financing activities	(873)	(115)	(900)
Effect of exchange rate changes on cash		(1)	10
Net increase (decrease) in cash and cash equivalents	921	151	(280)
Cash and cash equivalents, beginning of period	628	477	757
Cash and cash equivalents, end of period	$ 1,549	$ 628	$ 477

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

See Explanatory Note

(in millions)

	Common Stock	Additional Paid-In Capital	Subscriptions Receivable	Accumulated Other Comprehensive Loss	Retained Earnings (Accumulated Deficit)	Treasury Stock	Total
December 31, 2002 (Restated)	$ 3,831	$ 705	$ (12)	$ (55)	$ (2,145)	$ (68)	$ 2,256
Net loss					(692)		(692)
Other comprehensive income, net of tax				35			35
Series B Preferred Stock restructuring		(660)			1,224		564
Subscriptions receivable			4				4
Options exercised	15	(6)					9
Dividends and other distributions					(211)		(211)
401(k) plan and profit sharing stock	8						8
Options granted		2					2
December 31, 2003 (Restated)	$ 3,854	$ 41	$ (8)	$ (20)	$ (1,824)	$ (68)	$ 1,975
Net loss					(15)		(15)
Other comprehensive income, net of tax				7			7
Options exercised	5	(6)					(1)
Dividends and other distributions					(22)		(22)
401(k) plan and profit sharing stock	6						6
Options and restricted stock granted		6					6
December 31, 2004 (Restated)	$ 3,865	$ 41	$ (8)	$ (13)	$ (1,861)	$ (68)	$ 1,956
Net income					103		103
Other comprehensive income, net of tax				17			17
Options exercised	4	1				(1)	4
Dividends and other distributions					(22)		(22)
401(k) plan and profit sharing stock	5						5
Options and restricted stock granted		9					9
Shareholder litigation settlement	81						81
December 31, 2005	$ 3,955	$ 51	$ (8)	$ 4	$ (1,780)	$ (69)	$ 2,153

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions)

	Year Ended December 31,		
	2005	**2004**	**2003**
Net income (loss)	$ 103	$ (15)	$ (692)
Cash flow hedging activities, net:			
Unrealized mark-to-market gains (losses) arising during period, net	(70)	(62)	39
Reclassification of mark-to-market (gains) losses to earnings, net	84	36	(37)
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $(8), $16 and $(1), respectively)	14	(26)	2
Foreign currency translation adjustments	8	(11)	24
Minimum pension liability (net of tax benefit (expense) of $3, $(26) and $(5), respectively)	(5)	44	9
Other comprehensive income, net of tax	17	7	35
Comprehensive income (loss)	$ 120	$ (8)	$ (657)

See the notes to the consolidated financial statements.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Explanatory Note

Our Annual Report on Form 10-K for the fiscal year ended December 31, 2005 includes a restatement of our consolidated balance sheet and our consolidated statement of stockholders equity as of December 31, 2004 and periods prior to 2004. The restatement relates to our deferred income tax accounts. As previously disclosed in our 2004 Form 10-K, we undertook an evaluation of our tax accounting and reconciliation controls and processes, including a tax basis balance sheet review, which resulted in an adjustment to our deferred tax liability balance. We have since identified mistakes in the tax basis balance sheet review, which totaled an $89 million overstatement of the deferred tax liability balance. Although these mistakes were not considered material, either individually or in the aggregate, to the period to which they related, the mistakes are material, in the aggregate, to our 2005 results. We are required to restate prior periods in accordance with APB 20, Accounting Changes.

Summary. This restatement has no effect on our reported net income or reported cash provided by (used in) operating activities, investing activities or financing activities for any periods presented. A synopsis of the aggregate financial impact of this restatement on the amounts originally reported in our 2004 Form 10-K is as follows:

RESTATED SELECTED BALANCE SHEET DATA

	December 31, 2004
	(in millions)
Current Assets Deferred income taxes	
As previously reported	$ 74
Restatement	(12)
As restated	$ 62
Total Current Assets	
As previously reported	$ 2,740
Restatement	(12)
As restated	$ 2,728
Other Assets Deferred income taxes	
As previously reported	$ 12
Restatement	3

As restated	$	15
Total Assets		
As previously reported	$	9,852
Restatement		(9)
As restated	$	9,843
Other Liabilities Deferred income taxes		
As previously reported	$	597
Restatement		(98)
As restated	$	499
Total Liabilities		
As previously reported	$	7,479
Restatement		(98)
As restated	$	7,381
Stockholders Equity		
As previously reported	$	1,867
Restatement		89
As restated	$	1,956

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In addition, we have restated Stockholders Equity by $89 million at December 31, 2003 from $1,886 million to $1,975 million and at December 31, 2002 from $2,167 million to $2,256 million.

Note 1 Organization and Operations of the Company

Dynegy Inc. (together with our subsidiaries, we , us or our) is a holding company and conducts substantially all of its business through its 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 our Kendall and Sterlington power tolling arrangements (and does not include the Sithe toll which is now in GEN-NE and is an intercompany agreement) as well as our physical gas supply contracts, gas transportation contracts and remaining 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, interest and depreciation and amortization. As described below, our natural gas liquids business, which was conducted through DMSLP and its subsidiaries, was sold to Targa on October 31, 2005. Additionally, as described below, our former regulated energy delivery business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation on September 30, 2004.

Note 2 Accounting Policies

Our accounting policies conform to GAAP. Our most significant accounting policies are described below. The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and judgments that affect our reported financial position and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) developing fair value assumptions, including estimates of future cash flows and discount rates, (2) analyzing tangible and intangible assets for possible impairment, (3) estimating the useful lives of our assets, (4) assessing future tax exposure and the realization of tax assets, (5) determining amounts to accrue for contingencies, guarantees and indemnifications and (6) estimating various factors used to value our pension assets and liabilities. Actual results could differ materially from our estimates.

Principles of Consolidation. The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries, VIE s for which we are the primary beneficiary and our proportionate share of assets, liabilities, revenues and expenses of undivided interests in certain gas processing facilities. Intercompany accounts and transactions have been eliminated. The revenues and expenses of these undivided interests are included in income from continued operations, net in our consolidated statement of operations. Certain reclassifications have been made to prior-period amounts to conform with current-period financial statement classifications.

Cash and Cash Equivalents**.** Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid short-term investments with original maturities of three months or less.

Restricted Cash**.** Restricted cash represents cash that is not readily available for general purpose cash needs. Restricted cash at December 31, 2005 includes cash posted to support the letter of credit component of our

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amended and Restated Credit Facility. We are required to post cash collateral in an amount equal to 103% of outstanding letters of credit. We included this balance at December 31, 2005 in current assets due to the expected replacement of the cash collateralized facility in the next 12 months. Restricted cash at December 31, 2005 also includes amounts related to the terms of the indenture governing the Independence senior debt, which among other things, prohibit cash distributions by Independence to its affiliates, including Dynegy, unless certain project reserve accounts are funded to specified levels and the required debt service coverage ratio is met. Independence also has restricted investment balances which are included in prepayments and other current assets and restricted investments on our consolidated balance sheets. In our Forms 10-Q for the periods ended March 31, 2005, June 30, 2005 and September 30, 2005, we included $(17) million, $8 million and $(26) million, respectively, of decreases (increases) in restricted cash associated with the Independence senior debt in financing cash flows on the consolidated statements of cash flows. We have included all changes in restricted cash, including those associated with the Independence senior debt, in investing cash flows on the consolidated statements of cash flows in this Form 10-K.

Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivable if it becomes probable we will not collect all or part of outstanding balances. We review collectibility and establish or adjust our allowance as necessary primarily using a percent of balance methodology and methodologies involving historical levels of write-offs. The specific identification method is also used in certain circumstances.

Investment in Unconsolidated Affiliates. Investments in affiliates over which we exercise significant influence, generally occurring in ownership interests of 20% to 50%, and also occurring in lesser ownership percentages due to voting rights or other factors, are accounted for using the equity method. Our share of net income from these affiliates is reflected in the consolidated statements of operations as earnings from unconsolidated investments. Any excess of our investment in affiliates, as compared to our share of the underlying equity that is not recognized as goodwill, is amortized over the estimated economic service lives of the underlying assets. Other investments over which we may not exercise significant influence and that have readily determinable fair values are considered available-for-sale and are recorded at quoted market values. Investments over which we may not exercise significant influence and that do not have readily determinable fair values are recorded at the lower of cost or net realizable value. For securities with readily determinable fair values, the change in the unrealized gain or loss, net of deferred income tax, is recorded as a separate component of accumulated other comprehensive loss in the consolidated statements of comprehensive income (loss). Realized gains and losses on investment transactions are determined using the specific identification method. All investments in unconsolidated affiliates are periodically assessed for other-than-temporary declines in value, with write-downs recognized in earnings from unconsolidated investments in the consolidated statements of operations.

Concentration of Credit Risk. We sell our energy products and services to customers in the electric and gas distribution industries and to entities engaged in industrial and petrochemical businesses. These industry concentrations have the potential to impact our overall exposure to credit risk, either positively or negatively, because the customer base may be similarly affected by changes in economic, industry, weather or other conditions.

At December 31, 2005, our credit exposure as it relates to the mark-to-market portion of our risk management portfolio totaled $318 million. To reduce our credit exposure, we execute agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to further reduce credit risk with certain counterparties by obtaining third party guarantees or collateral as well as the right of termination in the event of default.

Our Credit Department, based on guidelines approved by the Board of Directors, establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical delivery and financial contracts. Our credit risk system provides current credit exposure to counterparties on a daily basis.

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We enter into master netting agreements both to mitigate credit exposure and to reduce collateral requirements. In general, the agreements include our risk management subsidiaries and allow the aggregation of credit exposure, margin and set-off. As a result, we decrease a potential credit loss arising from a counterparty default.

We include cash collateral deposited with counterparties in Prepayments and other current assets and Other long-term assets on our consolidated balance sheets. We include cash collateral due to counterparties in accrued liabilities and other current liabilities on our consolidated balance sheets.

Inventory. Our natural gas, coal, emission allowances and fuel oil inventories are carried at the lower of weighted average cost or at market. Our materials and supplies inventory is carried at the lower of cost or market using the specific identification method.

We adopted EITF 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, in the fourth quarter 2005. Accordingly, we account for exchanges of inventory with the same counterparty as one transaction.

If we have more emissions allowances on hand than are required to operate our facilities, we may sell these allowances. In the past, we have sold emissions allowances that relate to future periods. To the extent the proceeds received from the sale of such allowances exceeds our cost, we defer the associated gain until the period to which the allowance relates. As of December 31, 2005, we had aggregate deferred gains of $22 million, consisting of $11 million included as other accrued liabilities and $11 million included as other long-term liabilities, respectively, on our consolidated balance sheets. As of December 31, 2004, we had aggregate deferred gains of $16 million, consisting of $11 million included as other accrued liabilities and $5 million included as other long-term liabilities, respectively, on our consolidated balance sheets.

Property, Plant and Equipment. Property, plant and equipment, which has consisted principally of power generating facilities, gas gathering, processing, fractionation, terminalling and storage facilities, natural gas transportation lines and pipelines, is recorded at historical cost. Expenditures for major replacements, renewals and major maintenance are capitalized. We consider major maintenance to be expenditures incurred on a cyclical basis to maintain and prolong the efficient operation of our assets. Expenditures for repairs and minor renewals to maintain assets in operating condition are expensed. Depreciation is provided using the straight-line method over the estimated economic service lives of the assets, ranging from 3 to 40 years. Composite depreciation rates (which we refer to as composite rates) are applied to functional groups of assets having similar economic characteristics. The estimated economic service lives of our functional asset groups are as follows:

Asset Group	Range of Years

Power Generation Facilities	20 to 40
Transportation Equipment	5 to 10
Buildings and Improvements	10 to 39
Office and Miscellaneous Equipment	3 to 20

Gains and losses on sales of individual assets are reflected in gain (loss) on sale of assets, net in the consolidated statements of operations. We assess the carrying value of our property, plant and equipment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the related discounted cash flows of the assets and recording a loss if the resulting estimated fair value is less than the book value. For assets identified as held for sale, the book value is compared to comparable market prices, or the estimated fair value if comparable market prices are not readily available, to determine if an impairment loss

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is required. Please read Note 5 Restructuring and Impairment Charges beginning on page F-29 for a discussion of impairment charges we recognized in 2005, 2004 and 2003.

Asset Retirement Obligations. We adopted SFAS No. 143, Asset Retirement Obligations, effective January 1, 2003. Under the provisions of SFAS No. 143, we are required to record legal obligations to retire tangible, long-lived assets on our balance sheets as liabilities, which are recorded at a discount when the liability is incurred. Significant judgment is involved in estimating future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. If our estimates on the amount or timing of the cash flow change, the change may have a material impact on our results of operations.

As part of the transition adjustment in adopting SFAS No. 143, existing environmental liabilities in the amount of $73 million were reversed in the first quarter 2003. The fair value of the remediation costs estimated to be incurred upon retirement of the respective assets is included in the ARO and was recorded upon adoption of SFAS No. 143. Since the previously accrued liabilities exceeded the fair value of the future retirement obligations, the impact of adopting SFAS No. 143 was an increase in earnings, net of tax, of $34 million in the first quarter 2003, which is included in cumulative effect of change in accounting principles in the consolidated statements of operations. In addition to these liabilities, we also have potential retirement obligations for dismantlement of power generation facilities. Our current intent is to maintain these facilities in a manner such that they will be operated indefinitely. As such, we cannot estimate any potential retirement obligations associated with these assets. Liabilities will be recorded in accordance with SFAS No. 143 at the time we are able to estimate any new AROs.

In March 2005, the FASB issued Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, which is an interpretation of SFAS No. 143. FIN No. 47 defines a conditional ARO as an ARO for which the timing and/or method of settlement are conditional upon future events that may or may not be within the control of the entity. Uncertainty about the timing and method of settlement for a conditional ARO should be considered in estimating the ARO when sufficient information exists. FIN No. 47 clarifies when sufficient information exists to reasonably estimate the fair value of an ARO. We adopted the provisions of FIN No. 47 effective December 31, 2005. Under the provisions of this interpretation, we recorded additional asset retirement obligations in order to provide for the future removal of asbestos containing materials from certain of our generating facilities. As a result, we recorded an after-tax charge of $5 million, which is included in the consolidated statements of operations as a cumulative effect of change in accounting principles. FIN No. 47, if it had been adopted as of January 1, 2003, would have had no material effect on our results of operations or earnings per share, and would have resulted in an additional $14 million of AROs included in our long-term liabilities at December 31, 2004.

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In addition to the AROs discussed above, our AROs relate to activities such as ash pond and landfill capping, dismantlement of power generation facilities, closure and post-closure costs, environmental testing, remediation, monitoring and land and equipment lease obligations. Annual amortization of the assets associated with the AROs was $2 million, $2 million and $7 million in 2005, 2004 and 2003, respectively. A summary of changes in our AROs by reportable segment is as follows:

	GEN-MW	GEN-NE	GEN-SO	NGL	REG	Total
	(in millions)					
Balance at December 31, 2003	$ 29	$ 1	$	$ 10	$ 1	$ 41
Accretion expense	4			1		5
Other (1)	1				(1)	
Balance at December 31, 2004	34	1		11		46
Accretion expense	4					4
Sale of DMSLP				(11)		(11)
Implementation of FIN No. 47	10	6				16
Other (2)		1				1
Balance at December 31, 2005	$ 48	$ 8	$	$	$	$ 56

(1) During 2004, a land lease, and the related ARO, formerly held by our REG segment was transferred to our GEN-MW segment. In addition, AROs totaling less than $1 million were removed following our sales of Sherman and our interest in Indian Basin. There were no additional AROs recorded or settled, nor were there any revisions to estimated cash flows associated with existing AROs, during 2004.

(2) During 2005, we determined we would be obligated to dismantle our Danskammer generating facility upon its retirement. Therefore, we recorded an ARO in the amount of $1 million. There were no additional AROs, other than those recorded under the provisions of FIN No. 47, recorded or settled during 2005. There were no revisions to estimated cash flows associated with existing AROs during 2005.

Contingencies, Commitments, Guarantees and Indemnifications. We are involved in numerous lawsuits, claims, proceedings, joint venture audits and tax-related audits in the normal course of our operations. In accordance with SFAS No. 5, Accounting for Contingencies, we record a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an ongoing basis to ensure that we have what we believe are appropriate reserves recorded on the consolidated balance sheets. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant. Our estimates and judgment could change based on new information, changes in laws or regulations, changes in management s plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from these estimates and judgments.

Liabilities for environmental contingencies are recorded when environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability. These assumptions involve the judgments and estimates of management and any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

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We follow the guidance of FIN No. 45 Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others for disclosures and accounting of various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification subject to FIN No. 45 is entered into, an estimated fair value of the underlying guarantee or indemnification is recorded. Some guarantees and indemnifications could have significant financial impact under certain circumstances, however management also considers the probability of such circumstances occurring when estimating the fair value. Actual results may materially differ from the estimated fair value of such guarantees and indemnifications.

Goodwill and Other Intangible Assets. Goodwill represents, at the time of an acquisition, the amount of purchase price paid in excess of the fair value of net assets acquired. We follow the guidance set forth in SFAS No. 142, Goodwill and Other Intangible Assets, when assessing the carrying value of our goodwill. Accordingly, we evaluate our goodwill for impairment on an annual basis and when events warrant an assessment. Our evaluation is based, in part, on our estimate of future cash flows. The estimation of fair value is highly subjective, inherently imprecise and can change materially from period to period based on, among other things, an assessment of market conditions, projected cash flows and discount rate. As a result of our sale of DMSLP to Targa, we currently have no remaining goodwill. Were we to have goodwill, we would perform our annual impairment test in the fourth quarter after our annual budgetary process, and we may record further impairment losses in future periods as a result of such test. Please read Note 11 Goodwill and Intangible Assets Goodwill beginning on page F-41 for discussion of impairment charges we recognized for 2003.

Intangible assets represent the fair value of assets, apart from goodwill, that arise from contractual rights or other legal rights. In accordance with SFAS No. 141, Business Combinations , we record only those intangible assets that are distinctly separable from goodwill and can be sold, transferred, licensed, rented, or otherwise exchanged in the open market. Additionally, we recognize intangible assets for those assets that can be exchanged in combination with other rights, contracts, assets or liabilities.

In accordance with SFAS No. 142, we initially record and measure intangible assets based on the fair value of those rights transferred in the exchange transaction in which the asset was acquired. Those measurements are based on quoted market prices for the asset, if available, or measurement techniques based on the best information available such as a present value of future cash flows measurement. Present value measurement techniques involve judgments and estimates made by management about prices, cash flows, discount factors and other variables and the actual value realized from those assets could vary materially from these judgments and estimates. We amortize intangible assets based on the useful life of the respective asset as measured by either the life of the contract or right that the asset is derived from. If the intangible asset does not have a finite life based on the contractual or legal right, an estimate is made of the useful life based on the pattern in which the economic benefits of the asset are expected to be consumed. Intangible assets are also subjected to impairment testing on a regular basis and an impairment loss is recognized if the carrying amount of an intangible exceeds its fair value.

Revenue Recognition. We utilize two comprehensive accounting models in reporting our consolidated financial position and results of operations as required by GAAP an accrual model and a fair value model. We determine the appropriate model for our operations based on guidance provided in applicable accounting standards and positions adopted by the FASB or the SEC. We have applied these accounting policies on a consistent basis during the three years in the period ended December 31, 2005.

The accrual model has historically been used to account for substantially all of the operations conducted in our GEN-MW, GEN-NE and GEN-SO segments. These segments consist largely of the ownership and operation of physical assets that we use in various generation operations. We earn revenue from our facilities in three

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primary ways: (1) sale of energy generated by our facilities; (2) sale of ancillary services, which 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; and (3) sale of capacity. We recognize revenue from these transactions when the product or service is delivered to a customer.

Additionally, the accrual model was used to account for substantially all of the operations conducted in our NGL and REG segments. These segments consisted largely of processing and delivery operations. The business of these segments included the separation of natural gas liquids into their component parts from a stream of natural gas and the transportation or transmission or commodities through pipelines or over transmission lines. End sales from these businesses resulted in physical delivery of commodities to our wholesale, commercial, industrial and retail customers. We recognized revenue from these transactions when the product or service was delivered to a customer.

The fair value model has historically been used to account for forward physical and financial transactions, occurring primarily in the CRM segment and the power generation business, which meet the definition of a derivative contract as defined by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The criteria are complex, but generally require these contracts to relate to future periods, to contain fixed price and volume components and to have terms that require or permit net settlement of the contract in cash or the equivalent. The FASB determined that the fair value model is the most appropriate method for accounting for these types of contracts. In part, this conclusion is based on the cash settlement provisions in these agreements, as well as the volatility in commodity prices, interest rates and, if applicable, foreign exchange rates, which impact the valuation of these contracts. Since these transactions may be settled in cash or the equivalent, the value of the assets and liabilities associated with these transactions is reported at estimated settlement value based on current forward prices and rates as of each balance sheet date.

Typically, derivative contracts can be accounted for in three different ways: (1) as an accrual contract, if the criteria for the normal purchase normal sale exemption are met and documented; (2) as a cash flow or fair value hedge, if the criteria are met and documented or (3) as a mark-to-market contract with changes in fair value recognized in current period earnings. Generally, we only mark-to-market through earnings our derivative contracts if they do not qualify for the normal purchase normal sale exemption or as a cash flow hedge. Because derivative contracts can be accounted for in three different ways, and as the normal purchase normal sale exemption and cash flow and fair value hedge accounting are elective, the accounting treatment used by another party for a similar transaction could be different than the accounting treatment we use.

In order to estimate the fair value of our portfolio of transactions which meet the definition of a derivative and do not qualify for the normal purchase normal sale exemption, we use a liquidation value approach assuming that the ability to transact business in the market remains at historical levels. The estimated fair value of the portfolio is computed by multiplying all existing positions in the portfolio by estimated prices, reduced by a time value of money adjustment and deduction of reserves for credit and price. The estimated prices in this valuation are based either on (1) prices obtained from market quotes, when there are an adequate number of quotes to consider the period liquid, or, if market quotes are unavailable, or the market is not considered to be liquid, (2) prices from a proprietary model which incorporates forward energy prices derived from market quotes and values from previously executed transactions. The amounts recorded as revenue change as these estimates are revised to reflect actual results and changes in market conditions or other factors, many of which are beyond our control.

In October 2002, as a component of EITF Issue 02-03, the EITF rescinded EITF Issue 98-10, which previously required use of mark-to-market accounting for our energy trading contracts. While the rescission of

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EITF Issue 98-10 reduced the number of contracts accounted for on a mark-to-market basis, it did not eliminate mark-to-market accounting. All derivative contracts that either do not qualify, or are not designated, as hedges or as normal purchases or sales continue to be marked-to-market in the consolidated statements of operations in accordance with SFAS No. 133. Any earnings or losses previously recognized under EITF Issue 98-10 that would not have been recognized under SFAS No. 133 were reversed in 2003 pursuant to adopting the provisions of EITF Issue 02-03. The cumulative effect of this change in accounting principle resulted in after-tax earnings of $21 million in 2003 and comprised the following items that are no longer required to be recorded using mark-to-market accounting (in millions):

Removal of net risk-management assets representing the value of natural gas storage contracts	$ (176)
Removal of other net risk-management assets	(24)
Removal of net risk-management liabilities representing the value of power tolling arrangements	103
Net change in risk-management assets and liabilities	(97)
Addition of inventory previously included in risk-management assets (1)	130
Pre-tax gain recorded from change in accounting principle	33
Income tax expense	(12)
After-tax gain recorded in the consolidated statements of operations	$ 21

(1) All of the natural gas inventory was sold during 2003.

Cash inflows and cash outflows associated with the settlement of risk management activities are recognized in net cash provided by (used in) operating activities on the consolidated statements of cash flows.

Income Taxes. We follow the guidance in SFAS No. 109, Accounting for Income Taxes, which requires that we use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our consolidated balance sheets.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and, to the extent we believe that it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

Management believes future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize assets for which no reserve has been established. While we have considered these factors in assessing the need for a valuation allowance, there is no assurance that a valuation

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allowance would not need to be established in the future if information about future years change. Any change in the valuation allowance would impact our income tax expense and net income in the period in which such a determination is made.

Please read Note 14 Income Taxes beginning on page F-48 for further discussion of our accounting for income taxes and any change in our valuation allowance.

Earnings Per Share. Basic earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period. Diluted earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period plus each share that would have been outstanding assuming the issuance of common shares for all potentially dilutive common shares outstanding during the period.

EITF Issue 04-8, The Effect of Contingently Convertible Instruments on Diluted Earnings per Share, became effective for all reporting periods ending after December 15, 2004. EITF Issue 04-8 requires virtually all dilutive financial instruments, including contingently convertible instruments, be included in the calculation of fully diluted earnings per share. For purposes of this issue, contingently convertible instruments are instruments that have embedded conversion features that contingently convert based on market price triggers settled based on specified market conditions. None of our convertible instruments meet such conditions, and as such, the adoption of EITF Issue 04-8 resulted in no additional inclusion of potentially dilutive shares in the calculation of diluted earnings per share and did not change our diluted earnings per share for any of the periods presented.

Foreign Currency. For subsidiaries whose functional currency is not the U.S. Dollar, assets and liabilities are translated at year-end rates of exchange and revenues and expenses are translated at monthly average exchange rates. Translation adjustments for the asset and liability accounts are included as a separate component of accumulated other comprehensive loss in stockholders equity. Currency transaction gains and losses are recorded in other income and expense, net on the consolidated statements of operations and totaled losses of approximately $4 million for the year ended December 31, 2005 and gains of approximately $1 million and $12 million for the years ended December 31, 2004 and 2003, respectively.

Employee Stock Options. On January 1, 2003, we adopted the fair-value based method of accounting for stock-based employee compensation under SFAS No. 123, Accounting for Stock-Based Compensation, and used the prospective method of transition as described under SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. Under the prospective method of transition, all stock options granted after January 1, 2003 are accounted for on a fair value basis. Options granted prior to January 1, 2003 continued to be accounted for using the intrinsic value method. Accordingly, for options granted prior to January 1, 2003, compensation expense is not reflected for employee stock options unless they were granted at an exercise price lower than market value on the grant date. We granted in-the-money options in the past and recognized compensation expense over the applicable vesting periods. No in-the-money stock options have been granted since 1999.

Please read Note 19 Capital Stock beginning on page F-67 for discussion of stock options and expense recognized for 2005, 2004 and 2003.

Had compensation cost for all stock options granted prior to 2003 been determined on a fair value basis consistent with SFAS No. 123, our net income (loss) and basic and diluted earnings (loss) per share amounts would have approximated the following pro forma amounts for the years ended December 31, 2005, 2004 and 2003, respectively.

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	Years Ended December 31,		
	2005	2004	2003
	(in millions, except per share data)		
Net income (loss) as reported	$ 103	$ (15)	$ (692)
Add: Stock-based employee compensation expense included in reported net loss, net of related tax effects	6	4	2
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(8)	(27)	(53)
Pro forma net income (loss)	$ 101	$ (38)	$ (743)
Earnings (loss) per share:			
Basic as reported	$ 0.21	$ (0.10)	$ 0.86
Basic pro forma	$ 0.20	$ (0.16)	$ 0.72
Diluted as reported	$ 0.21	$ (0.10)	$ 0.78
Diluted pro forma	$ 0.20	$ (0.16)	$ 0.66

Minority Interest. Minority interest on the consolidated balance sheets includes third party investments in entities that we consolidate, but do not wholly-own. The net pre-tax results attributed to minority interest holders in consolidated entities are included in minority interest income (expense) in the consolidated statements of operations. As of December 31, 2005, we no longer had any minority interest obligations. The minority interest investments were held in DMSLP which was sold to Targa on October 31, 2005. The related minority interest income (expense) was reclassed to Income from discontinued operations, net on our consolidated statements of operations.

Accounting Principles Adopted

EITF Issue 04-8. EITF Issue 04-8 became effective for all reporting periods ending after December 15, 2004. For further discussion, please read Earnings Per Share beginning on page F-19.

FIN No. 47. FIN No. 47 became effective for all for fiscal years ending after December 15, 2005. For further discussion, please read Asset Retirement Obligations beginning on page F-14.

EITF 04-13. We early adopted EITF 04-13 in the fourth quarter 2005. For further discussion, please read Inventory beginning on page F-13.

Accounting Principles Not Yet Adopted

SFAS No. 123(R). In December 2004, the FASB issued SFAS No. 123(R), Share-Based Payment, which revises SFAS No. 123. SFAS No. 123(R) is effective January 1, 2006 for all calendar year-end companies and requires companies to expense the fair value of employee stock options and other forms of stock-based compensation. This expense will be recognized over the period during which an employee is required to provide services in exchange for the award.

As noted in Employee Stock Options above, we transitioned to a fair value based method of accounting for stock-based compensation in the first quarter 2003. Our share-based payments primarily consist of stock options and restricted stock awards. For stock options, we determine the fair value of each stock option at the grant date using a Black-Scholes model. For restricted stock awards, we consider the fair value to be the closing price of the stock on the grant date. We recognize the fair value of our share based payments over the vesting periods of the awards, which is typically a three-year service period.

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When we adopt SFAS No. 123(R) effective January 1, 2006, we intend to use the modified prospective transition method permitted under this pronouncement. We have estimated our cumulative effect of implementing this standard, which consists entirely of a forfeiture adjustment, to be less than $1 million after tax. Upon adoption, we will calculate our windfall tax benefits using the short-cut method as allowed under SFAS No. 123(R).

SFAS No. 153. In December 2004, the FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets An Amendment of APB Opinion No. 29 . The guidance in APB Opinion No. 29, Accounting for Nonmonetary Transactions , is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in that Opinion, however, included certain exceptions to that principle. SFAS No. 153 amends Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of SFAS No. 153 are effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Early application is permitted and companies must apply the standard prospectively. The adoption of this standard is not expected to have a material effect on our results of operations, financial position or cash flows.

SFAS No. 154. In May 2005, the Financial Accounting Standards Board (FASB) issued SFAS No. 154, Accounting Changes and Error Corrections A Replacement of APB Opinion No. 20 and SFAS No. 3 . SFAS 154 changes the requirements for the accounting for and reporting of a change in accounting principle and applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS 154 requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. The provisions of SFAS No. 154 are effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. The adoption of this standard is not expected to have a material effect on our results of operations, financial position or cash flows.

FSP FIN No. 45-3. In November 2005, the FASB issued FASB Staff Position No. 45-3, Application of FASB Interpretation No. 45 to Minimum Revenue Guarantees Granted to a Business or Its Owners (FSP FIN No. 45-3). It served as an amendment to FASB Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others by adding minimum revenue guarantees to the list of examples of contracts to which FIN No. 45 applies. Under FSP FIN No. 45-3, a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. FSP FIN No. 45-3 is effective for new minimum revenue guarantees issued or modified on or after January 1, 2006.

EITF Issue 05-6. In June 2005, the EITF reached consensus on Issue No. 05-6, Determining the Amortization Period for Leasehold Improvements . EITF Issue 05-6 provides guidance on determining the amortization period for leasehold improvements acquired in a business combination or acquired subsequent to lease inception. The guidance in EITF Issue 05-6 will be applied prospectively and is effective for periods beginning after June 29, 2005. The adoption of this standard is not expected to have a material effect on our results of operations, financial position or cash flows.

Note 3 Acquisition

Sithe Energies. On January 31, 2005, we acquired 100% of the outstanding common shares of ExRes, the parent company of Sithe Energies and Independence. The results of the operations of ExRes have been included in our consolidated financial statements since that date. Through this acquisition, we acquired the 1,021 MW

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Independence power generation facility located near Scriba, New York, as well as four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. We have not consolidated the entities that own these four natural gas-fired facilities and four hydroelectric generation facilities, in accordance with the provisions of FIN No. 46R. See Note 10 Unconsolidated Investments Variable Interest Entities beginning on page F-39 for additional discussion of these facilities. In addition to these power plants, we acquired the 740 MW firm capacity sales agreement between Independence and Con Edison, a subsidiary of Consolidated Edison, Inc. This agreement, which runs through 2014, will provide us with annual cash receipts of approximately $100 million, subject to the restrictions on distribution under Independence s indebtedness. 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. Independence holds power tolling, financial swap and other contracts with other Dynegy subsidiaries. As a result of the acquisition, these contracts have become intercompany agreements, and their financial statement impact has been substantially eliminated. This transaction enabled us to address one of our outstanding power tolling arrangements and to expand our generation capacity in a market where we have an existing presence.

The aggregate purchase price was comprised of (i) $135 million cash, which was reduced by a purchase price adjustment of approximately $2 million; (ii) transaction costs of approximately $16 million, approximately $3 million of which were paid in 2004 and (iii) the assumption of $919 million of face value project debt, which was recorded at its fair value of $797 million as of January 31, 2005. Please read Note 12 Debt Independence Debt beginning on page F-45 for additional information regarding the debt assumed.

The allocation of purchase price to specific assets and liabilities is based, in part, upon outside appraisals using customary valuation procedures and techniques. That allocation changed during the fourth quarter 2005 after receiving information related to investment valuations and tax basis balances. The acquisition resulted in an excess of the fair value of assets acquired over cost of the acquisition. This excess was then allocated to property plant and equipment and intangible assets acquired, including intangibles arising from contracts with us, on a pro-rata basis**.** The following table summarizes the fair values of the assets and liabilities acquired at the date of acquisition, January 31, 2005 (in millions):

Other current assets	$ 88
Restricted cash and investments	132
Property, plant and equipment	353
Assets from risk-management activities	62
Intangible assets	657
Other assets	4
Total assets acquired	$ 1,296
Current liabilities	$ (98)
Deferred income taxes	(193)
Other long-term liabilities	(59)
Long-term debt	(797)
Total liabilities assumed	$ (1,147)

Net assets acquired	$	149

Included in the assets acquired are restricted cash and investments of approximately $132 million. The restricted investments include Federal Home Loan Bank Bonds, U.S. Treasury Bonds, and high-grade short-term commercial paper. The restricted cash and investments are related to a sinking fund required by Independence s debt instruments, including a major overhaul reserve, a debt service reserve, a principal payment reserve, an

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interest reserve and a project restoration reserve. Restrictions on the cash and investments are scheduled to be lifted at the end of the project financing term in 2014. For further discussion, please read Note 12 Debt Independence Debt beginning on page F-45.

Of the $657 million of acquired intangible assets, $488 million was allocated to the firm capacity sales agreement with Con Edison. This asset will be amortized on a straight-line basis over the remaining life of the contract as a reduction to revenue in our consolidated statements of operations, through October 2014. In addition, Independence holds a power tolling contract, and a gas supply agreement with another of our subsidiaries, which were valued at $153 million and $16 million, respectively, as of January 31, 2005. Upon completion of our purchase of Independence, the power tolling agreement and the gas supply agreement were effectively settled, which resulted in a 2005 charge equal to their fair values, in accordance with EITF Issue 04-01, Accounting for Pre-existing Contractual Relationships Between the Parties to a Purchase Business Combination. As a result, we recorded a 2005 pre-tax charge of $169 million, which is included in cost of sales on our consolidated statements of operations. Upon settlement of the power tolling and gas supply agreements, the firm capacity sales agreement with Con Edison is the only remaining intangible asset associated with the acquisition of ExRes, which is included in intangibles and prepaids and other current assets on our consolidated balance sheets.

We have exercised our right to require Exelon to decommission, sell, or otherwise dispose of all four natural gas-fired merchant facilities owned by ExRes. Under the terms of the purchase agreement, Exelon will direct the disposition of these facilities, and will indemnify us with respect to all past and present operations. On June 1 and August 4, 2005 we entered into agreements, as directed by Exelon, to sell our ownership and operating interests in the four natural gas-fired power generation peaking facilities in upstate New York, which includes our 80% interest in an 84 MW plant in Massena and our 85% interest in an 83 MW plant in Ogdensburg to Alliance Energy Group LLC. The transactions, which were approved by the FERC and the New York Public Service Commission, closed on October 31, 2005 and had no impact on our consolidated financial statements as Exelon received the proceeds from the sale. Further, Exelon is entitled to cause us to decommission, sell, or bankrupt any or all of the four hydroelectric facilities owned by ExRes, for which we have been indemnified for any losses.

Note 4 Dispositions, Contract Terminations and Discontinued Operations

Dispositions and Contract Terminations

Sterlington Contract Termination. In December 2005, we announced that we had agreed to terminate the Sterlington long-term wholesale power tolling contract with Quachita Power LLC. Under the terms of the agreement, which closed on March 7, 2006, we paid Quachita Power LLC, a joint venture of GE Energy Financial Services and Cogentrix Energy, Inc., approximately $370 million to eliminate approximately $456 million in capacity payment obligations through 2012 and approximately $295 million in additional capacity payment obligations that would arise if Quachita exercised its option to extend the contract through 2017. We recognized a pre-tax charge of approximately $364 million ($229 million after-tax) in the fourth quarter 2005 related to this transaction. The charge is included in cost of sales on the consolidated statements of operations.

Sale of Illinois Power. On September 30, 2004, we sold all of our outstanding common and preferred shares of Illinois Power Company, which formerly comprised our REG segment, as well as our 20% interest in the Joppa power generation facility, to Ameren Corporation for $2.3 billion.

During the first quarter 2005, we paid approximately $5 million to Ameren for a final working capital purchase price adjustment. As a result of an adjustment to the contingent liabilities identified as part of the Illinois Power sale, we recorded a $12 million charge in the second quarter of 2005. On July 27, 2005, we paid $8 million in partial satisfaction of such contingent liabilities. For further discussion, please read Note 17

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Commitments and Contingencies Other Commitments and Contingencies Guarantees and Indemnification beginning on page F-63. The adjustment to the contingent liabilities resulted in an increase to our capital loss carryforward, and a corresponding increase to the deferred tax valuation allowance of $4 million.

During the first quarter 2004, Illinois Power met the held for sale classification requirements of SFAS No. 144, and continued to meet the requirements through the closing of the sale on September 30, 2004. SFAS No. 144 requires that long-lived assets not be depreciated or amortized while they are classified as held for sale. As such, we discontinued depreciation and amortization of Illinois Power s property, plant and equipment and regulatory assets, effective February 1, 2004. Depreciation and amortization expense related to Illinois Power totaled $10 million and $121 million in the years ended December 31, 2004 and 2003, respectively. In addition, SFAS No. 144 requires a loss to be recognized by the amount Assets held for sale less Liabilities held for sale are in excess of fair value less costs to sell. Accordingly, we recorded a pre-tax loss on the sale of $112 million in the year ended December 31, 2004. $58 million of the charge is reflected in gain on sale of assets, net and $54 million of the charge is reflected in impairment and other charges on our consolidated statements of operations.

Further, pursuant to SFAS No. 144, we are not reporting the results of Illinois Power s operations as a discontinued operation. If we were to account for Illinois Power as a discontinued operation, its results of operations would be condensed into loss from discontinued operations, net of taxes, on our consolidated statements of operations, and prior periods would be required to be restated to conform to this presentation. To qualify for discontinued operations classification, SFAS No. 144 and subsequent interpretations, specifically EITF Issue 03-13, Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations, require that the seller have no significant continuing involvement with the business being sold. However, we sell capacity and energy to Illinois Power under a two-year power purchase agreement which began in January 2005. Consequently, because we still have significant continuing involvement with Illinois Power, we will continue to include the historical results of Illinois Power s operations as part of our continuing operations. Additionally, power sales to Illinois Power occurring subsequent to the disposition will be reported in our consolidated statements of operations as third party sales. Approximately $459 million and $109 million of revenues, derived from power sales to Illinois Power occurring subsequent to the disposition, are reflected in our continuing operations for the period ending December 31, 2005 and 2004, respectively.

Had the results of Illinois Power been excluded from our comparative results as though the sale had occurred at the beginning of each respective period noted below, our revenues; loss before cumulative effect of changes in accounting principles, net of tax; net income (loss) applicable to common stockholders; and associated basic and diluted earnings (loss) per share would have approximated the following pro forma amounts for the years ended December 31, 2004 and 2003, respectively.

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	Years Ended December 31,	
	2004	2003
	(in millions, except per share data)	
Revenues:		
As reported	$ 2,451	$ 2,599
Pro forma	1,658	1,579
Loss before cumulative effect of change in accounting principles, net of tax:		
As reported	$ (15)	$ (732)
Pro forma	(32)	(478)
Net income (loss) applicable to common stockholders:		
As reported	$ (37)	$ 321
Pro forma	(54)	576
Earnings (loss) per share Income (loss) before cumulative effect of change in accounting principles, net of tax:		
Basic as reported	$ (0.10)	$ 0.75
Basic pro forma	$ (0.14)	$ 1.43
Diluted as reported	$ (0.10)	$ 0.69
Diluted pro forma	$ (0.14)	$ 1.29
Earnings (loss) per share Net income (loss) applicable to common stockholders:		
Basic as reported	$ (0.10)	$ 0.86
Basic pro forma	$ (0.14)	$ 1.54
Diluted as reported	$ (0.10)	$ 0.78
Diluted pro forma	$ (0.14)	$ 1.39

Joppa. In September 2004, we recorded a pre-tax gain of $75 million upon closing of the sale of our 20% interest in the Joppa power generating facility. This gain is included in earnings from unconsolidated investments on our consolidated statements of operations.

Sherman. In November 2004, we sold our Sherman natural gas processing facility located in Sherman, Texas. This sale resulted in a pre-tax gain of approximately $16 million. This gain is included in income from discontinued operations on our consolidated statements of operations.

Indian Basin. In April 2004, we sold our 16% interest in the Indian Basin Gas Processing Plant for approximately $48 million, and we recognized a pre-tax gain on the sale of approximately $36 million. This gain is included in income from discontinued operations on our consolidated statements of operations.

PESA. In April 2004, we sold our interest in the Plantas Eolicas, S.A. de R.L. 20 MW wind-powered electric generation facility located in Costa Rica for approximately $11 million. We recognized a pre-tax loss of approximately $1 million on the sale. This loss is included in gain (loss) on sale of assets, net on our consolidated statements of operations.

Kendall. In November 2004, DPM entered into a back to back power purchase agreement with Constellation Energy Commodities Group, Inc., or Constellation, under which Constellation will effectively receive DPM s rights to purchase approximately 570 MW of capacity and energy arising under DPM s tolling contract with LSP-Kendall Energy, LLC for a four-year term from December 2004 through November 2008.

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DPM will remain the primary obligor under the Kendall tolling contract, but will receive offsetting payments from Constellation during the four-year term.

In connection with this transaction, DPM paid to Constellation $117.5 million in cash and effectively eliminated approximately $161 million in our future fixed payment obligations under the Kendall tolling contract through November 2008. We recognized a pre-tax charge of approximately $115 million ($72 million after-tax) related to this transaction. The charge is included in cost of sales on the consolidated statements of operations.

Gas Transportation Contracts. In June 2004, we agreed to exit four long-term natural gas transportation contracts whose purpose was to secure firm pipeline capacity through 2014 in support of our former third party marketing and trading business. In exchange for exiting these obligations, we paid $20 million in June 2004, $16 million in December 2004 and $26 million in March 2005. This payment obligation was recorded at its fair value of $40 million and was accreted to $42 million over the period July 1, 2004 through March 31, 2005. Additionally, we reversed an aggregate liability of $148 million associated with the transportation contracts that was originally established in 2001 and recognized a pre-tax gain of $88 million related to these transactions. This gain is included in revenues on our consolidated statements of operations and is included in the results of our CRM segment. This agreement eliminated our obligation to make approximately $295 million in aggregate fixed capacity payments from April 2005 through 2014.

Batesville Tolling Arrangement. In December 2003, we reached an agreement with Virginia Electric and Power Company, a subsidiary of Dominion Resources, to terminate a wholesale power tolling contract totaling approximately 110 MW. Under the terms of the agreement, we paid Virginia Power $34 million to end the arrangement. As a result, we eliminated approximately $63 million in future capacity payments as well as collateral obligations of $12.5 million. We recognized a pre-tax loss of approximately $34 million ($22 million after-tax) in connection with this agreement. The charge is included in cost of sales on the consolidated statements of operations.

Kroger Company Settlement. In July 2003, we reached a settlement with Kroger related to four power supply contracts. Under the terms of the settlement agreement, which was approved by the FERC, Kroger paid us approximately $110 million to terminate two of the four power contracts and to restructure at current market prices the remaining two contracts through which we provided electricity to Kroger subsidiary stores in California. We also resolved an outstanding FERC dispute related to contract pricing as part of the settlement.

The four contracts were derivatives under SFAS No. 133 and were carried at their fair value on the consolidated balance sheets, with changes in fair value recognized in earnings. Our net risk-management asset related to these contracts was approximately $140 million at June 30, 2003. Therefore, the $30 million difference between the settlement of $110 million and the carrying value of the net risk-management asset was recorded as a pre-tax charge ($19 million after-tax). The two restructured contracts were carried at fair value with changes in fair value recognized in earnings through August 2003, when such contracts were terminated. The charge is included in revenues on the consolidated statements of operations.

Southern Power Tolling Arrangements. In the second quarter 2003, we reached an agreement with Southern Power to terminate three power tolling arrangements among Dynegy, Southern Power and our respective affiliates covering an aggregate of 1,100 MW. Under the terms of the agreement, we paid Southern Power $155 million to terminate these arrangements. The terminations resulted in $89 million of net collateral being returned to us and eliminated our obligation to make $1.7 billion of capacity payments to Southern Power over the next 30 years. The transaction closed in May 2003, and we recognized a pre-tax loss of approximately $133 million ($84 million after-tax). The charge is included in cost of sales on the consolidated statements of operations.

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Hackberry LNG Project. During the first quarter 2003, we entered into an agreement to sell our interest in Hackberry LNG Terminal LLC, the entity we formed in connection with our proposed LNG terminal/gasification project in Hackberry, Louisiana, to Sempra LNG Corp., a subsidiary of San Diego-based Sempra Energy. The transaction closed in April 2003. At closing, we received an initial payment of $20 million and recognized a pre-tax gain of approximately $12 million ($8 million after-tax). We retained the right to receive additional contingent payments based upon project development milestones. In October 2003, we received a $15 million payment associated with the completion of a project milestone and recognized a pre-tax gain of $15 million ($9 million after-tax). In March 2004, we sold our remaining financial interest in this project, which interest included rights to receive future contingent payments under the 2003 agreement, for $17 million and recognized a pre-tax gain of $17 million. These gains are included in income from discontinued operations on our consolidated statements of operations.

SouthStar Energy Services. During the first quarter 2003, we completed the sale of our 20% equity investment in SouthStar Energy Services LLC. We received approximately $20 million cash and recognized a pre-tax gain of approximately $1 million ($1 million after-tax). The gain is included in gain (loss) on sale of assets, net on our consolidated statements of operations.

Discontinued Operations

As part of our restructuring plan, we sold or liquidated our communications business and our U.K. CRM business in 2003. During 2005, we sold DMSLP, which comprised substantially all of the operations of our NGL segment. These transactions have been accounted for as discontinued operations under SFAS No. 144, as further described below.

Natural Gas Liquids. On October 31, 2005, we completed the sale of DMSLP, which comprised substantially all of the remaining operations of our NGL segment, to Targa Resources Inc. and two of its subsidiaries, which we refer to as Targa , for $2.441 billion in cash. At closing, we received $2.35 billion in cash proceeds. Prior to December 31, 2005, we received a substantial majority of the balance of the sales proceeds from Targa, which represented our cash collateral related to DMSLP. Targa assumed responsibility for approximately $47 million in letters of credit provided by us for the benefit of DMSLP, and those letters of credit had all been replaced by December 31, 2005.

DMSLP qualified as held for sale under SFAS No. 144 beginning in the second quarter 2005. SFAS No. 144 requires that long-lived assets not be depreciated or amortized while they are classified as held for sale. As such, we discontinued depreciation and amortization of NGL s property, plant and equipment, effective June 1, 2005. Depreciation and amortization expense related to NGL totaled $38 million, $88 million and $81 million during the years ended December 31, 2005, 2004 and 2003, respectively. Also during 2005, as a result of the anticipated sale of DMSLP, we reduced the valuation allowance on our deferred tax asset. For further discussion, please read Note 14 Income Taxes Change in Valuation Allowance beginning on page F-52. We recorded a pre-tax gain of approximately $1.1 billion ($675 million after-tax), subject to post-closing adjustments, upon closing of the transaction.

Pursuant to SFAS No. 144, we are reporting the results of NGL s operations as a discontinued operation. Accordingly, the results of operations of our NGL segment have been included in discontinued operations for all periods presented. EITF Issue 87-24, Allocation of Interest to Discontinued Operations, requires that interest expense on debt that is required to be repaid upon the sale of DMSLP should be reclassified to discontinued operations. Therefore, interest expense on our term loan scheduled to mature in 2010 and our generation facility debt scheduled to mature in 2007 has been allocated to discontinued operations, as the respective debt instruments were required to be paid upon the sale of DMSLP. Such interest expense, inclusive of amortization of debt issuance costs, totaled \$53 million, \$27 million and \$6 million for the years ended December 31, 2005, 2004 and 2003, respectively.

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Additionally, results from NGL s operations include revenues and cost of sales arising from intersegment transactions, which, other than the short term arrangement described below, will cease after the sale of DMSLP. NGL processes natural gas and sells this natural gas to CRM for resale to third parties. NGL also purchases natural gas from CRM and electricity from GEN. As the intersegment revenues and cost of sales included in NGL s results were reclassified to discontinued operations, the effects of these intersegment transactions eliminated in consolidation, including the ultimate third party settlement, previously recorded in other segments, have also been reclassified to discontinued operations.

In conjunction with the sale of DMSLP, certain natural gas sales and purchase agreements between DMSLP and CRM were extended through November 30, 2005. Under these agreements, which until the sale were intersegment agreements, CRM purchased natural gas from DMSLP field processing plants or sold natural gas for use as fuel or plant thermal reduction (PTR) replacement in certain of DMSLP s fractionation and non-operated Gulf Coast processing facilities. DMSLP has paid CRM essentially all costs it incurred in the sale, procurement and provisioning of natural gas under these agreements.

Global Liquids. We sold our global liquids business, included in our NGL segment, in 2002.

U.K. CRM. We substantially completed our exit from the U.K. CRM business during the first quarter 2003. For the year ended December 31, 2003, we recognized an after-tax loss of $21 million, primarily as a result of selling and terminating all of our U.K. gas and power positions, as well as administrative expenses, depreciation and amortization, shut-down costs and currency translation losses. Collateral postings totaling $98 million were eliminated with the selling/terminations of these positions. We do not expect the U.K. CRM business to have a material impact on our future results.

Global Communications. During January 2003, we disposed of Dynegy Europe Communications to an affiliate of Klesch & Company, a London-based private equity firm. We recognized an after-tax gain on the sale of approximately $19 million in the first quarter 2003.

During May 2003, we disposed of our U.S. communications network held by DynegyConnect, L.P. to an affiliate of 360 networks Corporation. During the second quarter 2003, we recognized an after-tax gain on the sale of approximately $2 million. Approximately $12 million of undiscounted obligations with respect to this business remain following these sales.

Other. Other includes Northern Natural and our U.K. natural gas storage business. We sold our ownership interest in these businesses in 2002.

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The following table summarizes information related to our discontinued operations:

	U.K. CRM	DGC	NGL	Other	Total
			(in millions)		
2005					
Revenue	$	$	$ 4,125	$	$ 4,125
Income (loss) from operations before taxes	6		163		169
Income (loss) from operations after taxes	(1)	2	236		237
Gain on sale before taxes			1,087		1,087
Gain on sale after taxes			675		675
2004					
Revenue	$	$	$ 3,753	$	$ 3,753
Income (loss) from operations before taxes	19	3	254		276
Income (loss) from operations after taxes	(7)	2	170		165
2003					
Revenue	$ 21	$ 5	$ 3,252	$	$ 3,278
Income (loss) from operations before taxes	(31)	(26)	148		91
Income (loss) from operations after taxes	(21)	(21)	98		56
Gain (loss) on sale before taxes		33		(2)	31
Gain (loss) on sale after taxes		26		(1)	25

In the year ending December 31, 2005, we recognized $3 million of pre-tax income primarily associated with U.K. CRM s receipt of a third party bankruptcy settlement offset by foreign currency exchange losses.

In the first quarter 2004, we recognized $17 million of pre-tax income related to translation gains on foreign currency in the U.K. Please read Note 6 Risk Management Activities and Financial Instruments Accounting for Derivative Instruments and Hedging Activities Net Investment Hedges in Foreign Operations beginning on page F-32 for further discussion. Also in the first quarter 2004, we recognized $3 million of pre-tax income associated with DGC s receipt of $3 million from a third party in settlement of a prior contractual claim. In the second quarter 2004, we recognized a tax expense of $20 million related to charges resulting from the conclusion of prior year tax audits.

Note 5 Restructuring and Impairment Charges

In 2005, we recorded $13 million, $10 million and $4 million in pre-tax impairments of our investments in Black Mountain, West Coast Power and Panama, respectively. For further information, please read Note 10 Unconsolidated Investments Power Generation South Investments beginning on page F-35. Also in 2005, we recorded in GEN-MW an impairment of an unused turbine totaling $29 million. We determined the fair value of the turbine based on market prices of similar assets available for sale. Also in 2005, we recorded severance and restructuring charges totaling $11 million. For further information, please read 2005 Restructuring below. Finally, in connection with our sale of DMSLP and included in discontinued operations were charges of $3 million and $2 million for cancellation fees and operating leases, respectively.

In 2004, we recorded pre-tax charges in impairment and other charges relating to our interest in Illinois Power totaling $112 million. For further discussion, please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23. In addition, during 2004, we recorded a $5 million pre-tax charge related to the impairment of one of our NGL assets. Also during 2004, we recorded $85 million in pre-tax impairments of our investment in West

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Coast Power. For further discussion please read Note 10 Unconsolidated Investments Power Generation South Investments beginning on page F-35.

In 2003, we recorded a goodwill impairment totaling $311 million and a pre-tax asset impairment totaling $218 million relating to our interest in Illinois Power. For further discussion, please read Note 11 Goodwill and Intangible Assets Goodwill beginning on page F-41 In addition, during 2003, we recorded a $26 million pre-tax charge related to the impairment of some of our generation investments. For further discussion, please read Note 10 Unconsolidated Investments Power Generation South Investments beginning on page F-35. Also, during 2003, we recorded a $12 million pre-tax charge related to the impairment of our investment in GCF. For further discussion, please read Note 10 Unconsolidated Investments NGL Investments beginning on page F-37.

2005 Restructuring. In December 2005 in order to better align our corporate cost structure with a single line of business and as part of a comprehensive effort to reduce on-going operating expenses, we announced a restructuring plan (the 2005 Restructuring Plan). The 2005 Restructuring Plan resulted in a reduction of approximately 40 positions and will be substantially complete by the end of the first quarter 2006. We recognized a pre-tax charge primarily in our Other and Eliminating segment of $11 million in the fourth quarter 2005, which is included in Impairment and other charges on our consolidated statement of operations and deferred approximately $1 million of charges until such time as transitional services are completed by certain affected employees. No cash payments associated with this restructuring had been made as of December 31, 2005.

2002 Restructuring. In October 2002, we announced a restructuring plan (the 2002 Restructuring Plan) designed to improve operational efficiencies and performance across our lines of business. The following is a schedule of 2005, 2004 and 2003 activity for the 2002 Restructuring Plan liabilities recorded associated with the cancellation fees, operating leases and severance:

	Severance	Cancellation Fees and Operating Leases	Total
		(in millions)	
Balance at December 31, 2003	$ 23	$ 30	$ 53
2004 adjustments to liability	18	7	25
2004 cash payments	(38)	(12)	(50)
Balance at December 31, 2004	$ 3	$ 25	$ 28
2005 cash payments		(9)	(9)

Balance at December 31, 2005	$ 3	$ 16	$ 19

During 2004, the adjustment to the accrued liability primarily reflects increases in the severance accrual due to changes in our estimate of the probable loss associated with the severance claims of our former chief executive officer and our former president. Cash payments during 2004 reflect payments made to our former chief executive officer and our former president.

Including the $2 million accrual for operating leases made in connection with the sale of DMSLP (for further information, please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids beginning on page F-27), we have an aggregate accrual of $18 million as of December 31, 2005 associated with operating leases. We expect this amount to be paid by the end of 2007 when the leases expire.

Note 6 Risk Management Activities and Financial Instruments

Our operations are impacted by several factors, some of which may not be mitigated by risk management methods. These risks include, but are not limited to, commodity price, interest rate and foreign exchange rate

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fluctuations, weather patterns, counterparty credit risks, changes in competition, operational risks, environmental risks and changes in regulations.

We define market risk as changes to our earnings and cash flow resulting from changes in market conditions, including changes in commodity prices, interest rates and currency rates as well as the impact of volatility and market liquidity on such prices. We seek to manage market risk through diversification, controlling position sizes and executing hedging strategies.

Accounting for Derivative Instruments and Hedging Activities

We follow the accounting and disclosure requirements of SFAS No. 133, as amended. Under SFAS No. 133, all derivative instruments are recognized in the balance sheet at their fair values and changes in fair value are recognized immediately in earnings, unless such instruments qualify, and are designated, as hedges of future cash flows, fair values or net investments in foreign operations or qualify, and are designated, as normal purchases and sales. We distinguish between these hedges, which are further described below, as follows:

> ***Cash flow hedges.*** Under these derivatives, the effective portion of changes in fair value is recorded as a component of accumulated other comprehensive loss until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported immediately as a component of income in the consolidated statements of operations. Ineffectiveness associated with cash flow hedges of commodity transactions and interest rate swaps is included in revenues and other income and expense, net, respectively.
>
> ***Fair value hedges.*** Under these derivatives, changes in the fair value of the derivative and changes in the fair value of the related asset or liability are recorded in current period earnings.
>
> ***Net investments in foreign operations.*** Under these derivatives, the effective portion of changes in the fair value of the derivative is recorded in the foreign currency translation adjustment, a component of accumulated other comprehensive loss. Any ineffective portion is reported immediately as a component of other income and expense, net in the consolidated statements of operations.

Cash Flow Hedges. We enter into financial derivative instruments that qualify as cash flow hedges. The maximum length of time for which we have hedged our exposure for cash flow hedges is through 2006. Instruments related to our generation business are entered into for purposes of hedging future fuel requirements and sales commitments. Interest rate swaps were previously used to convert the floating interest-rate component of some obligations to fixed rates.

During the years ended December 31, 2005, 2004 and 2003, we recorded $3 million, $(3) million and zero of income (expense), respectively, related to ineffectiveness from changes in fair value of hedge positions. No amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows in any of the periods. During the years ended December 31, 2005 and 2004, no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable of occurring. We recorded charges of less than $1 million during the year ended December 31, 2003.

The balance in cash flow hedging activities, net at December 31, 2005 is expected to be reclassified to future earnings, contemporaneously with the related purchases of fuel or sales of electricity, as applicable to each type of hedge. Of this amount, after-tax losses of approximately $7 million are currently estimated to be reclassified into earnings over the 12-month period ending December 31, 2006. The actual amounts that will be reclassified to earnings over this period and beyond could vary materially from this estimated amount as a result of changes in market prices, hedging strategies, the probability of forecasted transactions occurring and other factors.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fair Value Hedges. We also enter into derivative instruments that qualify as fair value hedges. The maximum length of time for which we have hedged our exposure for fair value hedges is through 2012. We use interest rate swaps to convert a portion of our non-prepayable fixed-rate debt into variable-rate debt. During the years ended December 31, 2005, 2004 and 2003, there was no ineffectiveness from changes in the fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. During the years ended December 31, 2005, 2004 and 2003, we recorded gains of zero, zero and $6 million, respectively, related to the recognition of firm commitments that no longer qualified as fair value hedges.

Net Investment Hedges In Foreign Operations. Although we have exited a substantial amount of our foreign operations, we have remaining investments in foreign subsidiaries, the net assets of which are exposed to currency exchange-rate volatility. In the past, we used derivative financial instruments, including foreign exchange forward contracts and cross-currency interest rate swaps, to hedge this exposure. As of December 31, 2005, 2004 and 2003 we had no net investment hedges in place to hedge that exposure.

During the year ended December 31, 2003, our efforts to exit the U.K. CRM business and the European communications business were substantially completed. As required by SFAS No. 52, Foreign Currency Translation, a significant portion of unrealized gains and losses resulting from translation and financial instruments utilized to hedge currency exposures previously recorded in stockholders equity were recognized in income, resulting in an after-tax loss of approximately $16 million. During the first quarter 2004, we repatriated a majority of our cash from the U.K. by repayment of intercompany loans, resulting in the substantial liquidation of our investment in the U.K. As such, we recognized approximately $17 million of pre-tax translation gains in income that arose since April 1, 2003 and had accumulated in stockholders equity.