DYNEGY HOLDINGS INC
Form 10-K
February 26, 2009

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

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

DYNEGY INC.
DYNEGY HOLDINGS INC.
(Exact name of registrant as specified in its charter)

Entity	Commission File Number	State of Incorporation	I.R.S. Employer Identification No.
Dynegy Inc.	001-33443	Delaware	20-5653152
Dynegy Holdings Inc.	000-29311	Delaware	94-3248415

1000 Louisiana, Suite 5800 **Houston, Texas** **(Address of principal executive offices)**	**77002** **(Zip Code)**

(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
Dynegy s Class A common stock, $0.01 par value	New York Stock Exchange

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

Title of each class	Name of each exchange on which registered
None	None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Dynegy Inc.	Yes þ No o
Dynegy Holdings Inc.	Yes o No þ

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.

Dynegy Inc.	Yes o No þ
Dynegy Holdings Inc.	Yes o No þ

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.

Dynegy Inc.	Yes þ No o
Dynegy Holdings Inc.	Yes þ No o

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.

Dynegy Inc.	o
Dynegy Holdings Inc.	þ

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

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
Dynegy Inc.	þ	o	o	o
Dynegy Holdings Inc.	o	o	þ	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Dynegy Inc.	Yes o No þ
Dynegy Holdings Inc.	Yes o No þ

As of June 30, 2008, the aggregate market value of the Dynegy Inc. common stock held by non-affiliates of the registrant was $4,298,466,775 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: For Dynegy Inc., Class A common stock, $0.01 par value per share, 503,666,984 shares outstanding as of February 20, 2009; Class B common stock, $0.01 par value per share, 340,000,000 shares outstanding as of February 20, 2009. All of Dynegy Holdings Inc. s outstanding common stock is owned indirectly by Dynegy Inc.
This combined Form 10-K is separately filed by Dynegy Inc. and Dynegy Holdings Inc. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to a registrant other than itself.
DOCUMENTS INCORPORATED BY REFERENCE-Dynegy Inc. Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant s 2009 Annual Meeting of Stockholders, which the registrant intends to file not later than 120 days after December 31, 2008.
REDUCED DISCLOSURE FORMAT-Dynegy Holdings Inc. Dynegy Holdings Inc. meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and therefore is filing this Form 10-K with the reduced disclosure format.

DYNEGY INC. and DYNEGY HOLDINGS INC.
FORM 10-K
TABLE OF CONTENTS

PART IV

EXPLANATORY NOTE

This report includes the combined filing of Dynegy Inc. (Dynegy) and Dynegy Holdings Inc. (DHI). DHI is the principal subsidiary of Dynegy, providing approximately 100 percent of Dynegy s total consolidated revenue for the year ended December 31, 2008 and constituting approximately 100 percent of Dynegy s total consolidated asset base as of December 31, 2008 except for Dynegy s former 50 percent interest in DLS Power Holdings, LLC (DLS Power Holdings) and DLS Power Development Company, LLC (DLS Power Development).

Unless the context indicates otherwise, throughout this report, the terms the Company , we , us , our and ours are u refer to both Dynegy and DHI and their direct and indirect subsidiaries. Discussions or areas of this report that apply only to Dynegy or DHI are clearly noted in such discussions or areas.

Table of Contents

PART I

DEFINITIONS

As used in this Form 10-K, the abbreviations contained herein have the meanings set forth in the glossary, which can be found in the Notes to Consolidated Financial Statements.

Item 1. *Business*

THE COMPANY

We are holding companies and conduct substantially all of our business operations through our subsidiaries. Our primary business is the production and sale of electric energy, capacity and ancillary services from our fleet of twenty-seven operating power plants in thirteen states totaling nearly 18,000 MW of generating capacity.

Dynegy began operations in 1985. DHI is a wholly owned subsidiary of Dynegy. Dynegy became incorporated in the State of Delaware in 2007 as a part of the LS Power transaction. Our principal executive office is located at 1000 Louisiana Street, Suite 5800, Houston, Texas 77002, and our telephone number at that office is (713) 507-6400.

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

We sell electric energy, capacity and ancillary services on a wholesale basis from our power generation facilities. Energy is the actual output of electricity and is measured in MWh. The capacity of a generation facility is its electricity production capability, measured in MW. Wholesale electricity customers will, for reliability reasons and to meet regulatory requirements, contract for rights to capacity from generating units. Ancillary services are the products of a generation facility that support the transmission grid operation, follow real-time changes in load and provide emergency reserves for major changes to the balance of generation and load. We sell these products individually or in combination to our customers under short-, medium- and long-term contractual agreements or tariffs.

Our customers include RTOs and ISOs, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, industrial customers, power marketers, financial participants such as banks and hedge funds, other power generators and commercial end-users. All of our products are sold on a wholesale basis for various lengths of time from hourly to multi-year transactions. Some of our customers, such as municipalities or integrated utilities, purchase our products for resale in order to serve their retail, commercial and industrial customers. Other customers, such as some power marketers, may buy from us to serve their own wholesale or retail customers or as a hedge against power sales they have made.

Table of Contents

Our Strategy

Our business strategy is designed to leverage our diverse portfolio of generating assets, our operational and commercial skills and our flexible capital structure to create value for our investors. In general, we seek to maximize the value of our assets through:

- safe and cost-efficient plant operations, with a focus on having our plants available and in the market when it is economical to do so;

- a diverse commercial strategy that includes short-, medium- and long-term sales of electric energy, capacity and ancillary services, and seeks to strike a balance between contracting for near/intermediate term stability of earnings and cash flows while maintaining merchant length to capitalize on expected increases in commodity prices in the longer term; and

- pursuit of plant expansions and growth opportunities that enhance our portfolio with acceptable rates of return and are accretive to stockholder value.

Maintain a Diverse Portfolio to Capitalize on Market Opportunities and Mitigate Risk. We operate a portfolio of generation assets that is diversified in terms of dispatch profile, fuel type and geography. 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 percent and 90 percent of the hours in a given year. Intermediate generation is not as efficient and/or economical as baseload generation but is intended to be dispatched during higher load times such as during daylight hours and sometimes on weekends. Peaking generation is the least efficient and highest cost generation and is generally dispatched to serve load during the highest load times such as hot summer and cold winter days.

Although power prices have declined since the summer of 2008, primarily due to the oversupply of natural gas in the market and the impact of the current economic environment, we continue to believe that the market fundamentals support long-term increases in power demand and power pricing. As such, we believe our substantial coal-fired, baseload fleet should benefit from the impact of higher power prices in the Midwest and Northeast, allowing us to capture significantly higher and increasing margins over the long-term as power prices increase. We anticipate that our combined cycle units also should benefit from improved margins and cash flows as demand increases in all of our key markets. Our peaking units effectively give us an option to capture greater value for our investors as supply and demand come more into equilibrium over the longer term.

In addition, we believe that a diverse portfolio of assets helps to mitigate the risks inherent in our business. For example, weather patterns, regulatory regimes and commodity prices often differ by region. By maintaining fleet diversity, we lessen the impact of an individual risk in any one region and seek to improve the level and consistency of our earnings and cash flows. We also believe our diverse fleet of generating assets positions us well to meet growing U.S. power needs; however, in the current recessionary environment, U.S. power consumption may decrease in the short-term.

Table of Contents

Our current operating generating facilities are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	Region
Baldwin	1,800	Coal	Baseload	Baldwin, IL	MISO
Kendall	1,200	Gas	Intermediate	Minooka, IL	PJM
Ontelaunee	580	Gas	Intermediate	Ontelaunee Township, PA	PJM
Havana Units 1-5	228	Oil	Peaking	Havana, IL	MISO
Unit 6	441	Coal	Baseload	Havana, IL	MISO
Hennepin	293	Coal	Baseload	Hennepin, IL	MISO
Oglesby	63	Gas	Peaking	Oglesby, IL	MISO
Stallings	89	Gas	Peaking	Stallings, IL	MISO
Tilton	188	Gas	Peaking	Tilton, IL	MISO
Vermilion Units 1-2	164	Coal/Gas	Baseload	Oakwood, IL	MISO
Unit 3	12	Oil	Peaking	Oakwood, IL	MISO
Wood River Units 1-3	119	Gas	Peaking	Alton, IL	MISO
Units 4-5	446	Coal	Baseload	Alton, IL	MISO
Rocky Road (2)	330	Gas	Peaking	East Dundee, IL	PJM
Riverside/Foothills	960	Gas	Peaking	Louisa, KY	PJM
Renaissance	776	Gas	Peaking	Carson City, MI	MISO
Bluegrass	576	Gas	Peaking	Oldham County, KY	SERC
Total Midwest	*8,265*				
Moss Landing Units 1-2	1,020	Gas	Intermediate	Monterrey County, CA	CAISO
Units 6-7	1,509	Gas	Peaking	Monterrey County, CA	CAISO
Morro Bay (3)	650	Gas	Peaking	Morro Bay, CA	CAISO
South Bay	706	Gas/Oil	Peaking	Chula Vista, CA	CAISO
Oakland	165	Oil	Peaking	Oakland, CA	CAISO
Arlington Valley	585	Gas	Intermediate	Arlington, AZ	Southwest
Griffith	558	Gas	Intermediate	Golden Valley, AZ	WAPA
Heard County (4)	539	Gas	Peaking	Heard County, GA	SERC
Black Mountain (5)	43	Gas	Baseload	Las Vegas, NV	WECC
Total West	*5,775*				
Independence	1,064	Gas	Intermediate	Scriba, NY	NYISO
Roseton (6)	1,185	Gas/Oil	Peaking	Newburgh, NY	NYISO
Bridgeport	527	Gas	Intermediate	Bridgeport, CT	ISO-NE
Casco Bay	540	Gas	Intermediate	Veazie, ME	ISO-NE
Danskammer Units1-2	123	Gas/Oil	Peaking	Newburgh, NY	NYISO
Units 3-4 (6)	370	Coal/Gas	Baseload	Newburgh, NY	NYISO

Total Northeast	*3,809*
Total Fleet Capacity	*17,849*

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

(2) Does not include 28 MW of capacity for unit 3, which is not available during cold weather because of winterization requirements.

(3) Represents units 3 and 4 generating capacity. Units 1 and 2, with a combined net generating capacity of 352 MW, are currently in lay-up status and out of operation.

(4) On February 25, 2009, we entered into an agreement to sell our interest in the Heard County power generation facility to Oglethorpe Power Corporation. Subject to regulatory approval, the transaction is expected to close in early 2009. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Heard County for further discussion.

(5) We own a 50 percent interest in this facility. Total output capacity of this facility is 85 MW.

(6) 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 Disclosure of Contractual Obligations and Contingent Financial Commitments Off-Balance Sheet Arrangements DNE Leveraged Lease.

Operate our Assets Safely and Cost-Efficiently to Maximize Revenue Opportunities and Operating Margins. We have a history of strong plant operations and are committed to operating our facilities in a safe, reliable and environmentally compliant manner. By maintaining and operating our assets in an effort to ensure plant availability, high dispatch and capacity factors and an appropriate level of operating and capital costs, we believe we are positioned to capture opportunities in the market place effectively and to maximize our operating margins.

With respect to cost controls, a key aspect of profitability is our cost to produce electricity. The main variable component of that cost is fuel. Our coal-fired generation facilities are our lowest variable cost facilities. Due to their low-cost nature, most of our coal-fired generation facilities run the majority of any given day throughout the year unless a particular unit is unavailable due to either planned or unplanned maintenance activity. In today s environment, our natural gas and fuel oil-fired power generation facilities are more expensive to operate than our coal-fired facilities. As a result, these plants only run on those days, or parts of days, when market demand and price are sufficient to economically justify dispatch of these higher cost units.

Our power generation facilities are managed to require a relatively predictable level of maintenance capital expenditures without compromising operational integrity. Our capital expenditures are for the maintenance of our facilities to ensure their continued reliability and for investment in new equipment for either environmental compliance or increasing profitability. We seek to operate and maintain our generation fleet efficiently and safely, with an eye toward future maintenance and improvements, resulting in increased reliability and environmental stewardship. This increased reliability impacts our results to the extent that our generation units are available during times that it is economically sound to run. For units that are subject to contracts for capacity, our ability to secure availability payments from customers is dependent on plant availability. We believe these ongoing efforts to focus on reliability should allow us to maintain focus on being a low-cost producer of power.

Employ a Flexible Commercial Strategy to Maintain Long-Term Market Upside Potential While Protecting Against Downside Risks. We expect to see tightening reserve margins through time in the regions in which our assets are located. As these reserve margins tighten, we expect to see the value of the generating assets themselves increase due to improvements in cash flow and earnings. When prices that equate to market recovery are transactable, longer-term contracts are advisable. However, given current market pricing and conditions, we do not see attractive long-term commercial arrangements.

We plan to sell the output from our facilities with the goal of achieving an efficient balance of risk and reward. Keeping the portfolio completely open and selling in the day-ahead market, for instance, would force us to take weather and general economic-related risks, as well as price risk of correlated commodities. These risks can cause significant swings in financial performance in any one year and are not related to our core strategy of realizing the benefit of long-term market recovery on fundamental generating asset values.

With a goal of protecting cash flow in the near/intermediate term while maintaining the ability to capture value longer term as markets tighten, we expect that a majority of our sales will be achieved by selling energy and capacity through a combination of spot market sales and near-term contracts over a rolling 12 36 month time frame in time periods that we describe as Current , Current +1 , and Current +2 . The Current period refers to the balance of the current calenda year. The Current+1 period refers to the next calendar year. Current +2 refers to the next calendar year after the Current +1 period. At any given point in time, we will seek to balance predictability of earnings and cash flow with achieving the highest level of earnings and cash flow possible over the Current, Current +1 and Current +2 periods. In these periods, short-term market volatility can negatively impact our profitability and we will seek to reduce those negative impacts through the disciplined use of near- and intermediate-term forward sales. We expect to make fewer forward sales beyond the Current+2 period in order to realize the anticipated benefit of improved market prices over time as the supply and demand balance tightens.

Beginning in January 2009, we have set specific limits for gross margin at risk for the entire portfolio and require power hedging up to minimum levels, while seeking to ensure that corresponding fuel supplies also are appropriately hedged, as we progress through time. We will also specifically manage basis risk to hubs that are not the natural sales hub for a facility and implement other changes that sharpen our focus on optimizing the commercial factors that we can control and mitigating commodity risk where appropriate.

4

Table of Contents

Maintain a Simple, Flexible Capital Structure that is Integrated with our Operating Strategy. We believe that the power industry is a commodity cyclical business with significant commodity price volatility and considerable capital investment requirements. Thus, maximizing economic returns in this market environment requires a capital structure that can withstand fuel and power price volatility as well as a commercial strategy that captures the value associated with both mid- and long-term price trends. We believe we have a capital structure that is suitable for our commercial strategy and the commodity cyclical market in which we operate. Maintaining appropriate debt levels and covenants, maturities and overall liquidity are key elements of this capital structure. This structure allows us to be opportunistic as we regularly evaluate potential combinations or asset acquisitions. We will also seek to harvest value through the opportunistic sale of existing assets where we believe we can capture greater value through a sale than we can by continuing to own or operate such assets.

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: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. The results of our former CRM segment are included in Other, as it did not meet the criteria required to be an operating segment as of January 1, 2008. Accordingly, we have restated the corresponding items of segment information for prior periods. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. Please read Note 22 Segment Information for further information regarding the financial results of our business segments.

NERC Regions, RTOs and ISOs. In discussing our business, we often refer to NERC regions. The NERC and its eight regional reliability councils (as of December 31, 2008) 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. For example, each NERC region establishes a minimum reserve requirement to ensure there is sufficient generating capacity to meet expected demand within its region. Each NERC region reports seasonally and annually on the status of generation and transmission in each region.

Separately, RTOs and ISOs administer the transmission infrastructure and markets across a regional footprint in some of the markets in which we operate. They are responsible for dispatching all generation facilities in their respective footprints and are responsible for both maximum utilization and reliable and efficient operation of the transmission system. RTOs and ISOs administer energy and ancillary service markets in the short term, usually day ahead and real-time markets. Several RTOs and ISOs also ensure long-term planning reserve through monthly, semi-annual, annual and multi-year capacity markets. The RTOs and ISOs that oversee most of the wholesale power markets currently impose, and will likely continue to impose, both bid and price limits. They may also enforce caps and other mechanisms to guard against the exercise of market power in these markets. NERC regions and RTOs/ISOs often have different geographic footprints and while there may be physical overlap between NERC regions and RTOs/ISOs, their respective roles and responsibilities do not generally overlap.

In RTO and ISO regions with centrally dispatched market structures, and zonal clearing structures (e.g. the ERCOT Region in Texas), all generators selling into the centralized market receive the same price for energy sold based on the bid price associated with the production of the last megawatt hour that is needed to balance supply with demand within a designated zone or at a given location (different zones or locations within the same RTO/ISO may produce different prices respective to other zones within the same RTO/ISO due to losses and congestion). For example, a less-efficient (i.e., more expensive) natural gas-fired unit may be needed in some hours to meet demand. If this unit s production is required to meet demand on the margin, its bid price will set the market clearing price that will be paid for all dispatched generation (although the price paid at other zones or locations may vary because of congestion and losses), regardless of the price that any other unit may have offered into the market. In RTO and ISO regions with centrally dispatched market structures and location-based marginal pricing clearing structures (e.g. PJM, NYISO, and ISO-NE), generators receive the location-based marginal price for their output. In regions that are outside the footprint of RTOs/ISOs, prices are determined on a bilateral basis between buyers and sellers.

5

Market Based Rates. Our ability to charge market-based rates for wholesale sales of electricity, as opposed to cost-based rates, is governed by FERC. We have been granted market-based rate authority for wholesale power sales from our EWG facilities, as well as wholesale power sales by our power marketing entities, Dynegy Power Marketing Inc. and Dynegy Marketing and Trade LLC. The Dynegy EWG facilities include all of our facilities except our investments in Nevada Cogeneration Associates #2 (Black Mountain), Allegheny Hydro Partners, Ltd., Allegheny No. 6 Hydro Partners, Ltd, Allegheny Hydro No. 8 Ltd. and Allegheny Hydro No. 9, Ltd. These facilities are known as QFs, and have various exemptions from federal regulation and sell electricity directly to purchasers under negotiated and previously approved power purchase agreements. Our market-based rate authority is predicated on a finding by FERC that our entities with market-based rates do not have market power, and a market power analysis is generally conducted once every three years for each region on a rolling basis (known as the triennial market power review). The triennial market power review for our Northeast and PJM assets was filed at FERC on August 29, 2008. FERC issued an order accepting this filing on December 12, 2008. The triennial market power review for our Southeast assets was filed with FERC on December 24, 2008. The triennial market power reviews for our West and MISO assets will be filed pursuant to a FERC established schedule.

Power Generation Midwest Segment

Our Midwest fleet is comprised of 14 facilities located in Illinois (10), Michigan (1), Pennsylvania (1) and Kentucky (2), with a total generating capacity of 8,265 MW. With the exception of our Bluegrass peaking facility in the Louisville Gas and Electric control area, our Midwest fleet as of December 31, 2008 operates entirely within either the MISO or the PJM.

RTO/ISO Discussion

MISO. The MISO market includes all of Wisconsin and Michigan and portions of Ohio, Kentucky, Indiana, Illinois, Nebraska, Kansas, Missouri, Iowa, Minnesota, North Dakota, Montana and Manitoba, Canada. As of December 31, 2008, we owned nine power generating facilities located in Illinois (8) and Michigan (1), with an aggregate net generating capacity of 4,619 MW within MISO.

MISO is designed to ensure that every electric industry participant has access to the grid and that no entity has the ability to deny access to a competitor. MISO also manages the use of transmission lines to make sure that they do not become overloaded. MISO operates physical and financial energy markets using a system known as LMP, which calculates a price for every generator and load point within the MISO area. This system is price-transparent , allowing generators and load serving entities to see real-time price effects of transmission constraints and impacts of generation and load changes to prices at each point. MISO operates day-ahead and real-time markets into which generators can offer to provide energy. FTRs allow users to manage the cost of transmission congestion (as measured by LMP differentials, between source and sink points on the transmission grid) and corresponding price differentials across the market area. MISO implemented the Ancillary Services Market (Regulation and Operating Reserves) on January 6, 2009 and plans to implement an enforceable Planning Reserve Margin for the 2009-2010 planning year. A feature of the Ancillary Services Market is the addition of scarcity pricing that, during supply shortages, can raise the combined price of energy and ancillary services significantly higher than the previous cap of $1,000/MWh. An independent market monitor is responsible for ensuring that MISO markets are operating competitively and without exercise of market power.

PJM. The PJM market includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. As of December 31, 2008, we owned four generating facilities located in Illinois (2), Pennsylvania (1) and Kentucky (1) with an aggregate net generating capacity of 3,070 MW within PJM. The majority of power generated by these facilities is sold to wholesale customers in the PJM market.

PJM administers markets for wholesale electricity and provides transmission planning for the region, utilizing the LMP system described above. PJM operates day-ahead and real-time markets into which generators can bid to provide electricity and ancillary services. PJM also administers markets for capacity. An independent market monitor continually monitors PJM markets for any exercise of market power or improper behavior by any entity. PJM implemented a forward capacity auction, the RPM, which established long-term markets for capacity in 2007. The RPM has provided locational price and multi-year dimensions to the capacity market, but has also led to some controversy. In December 2008, FERC responded to complaints about the new RPM rules by establishing a settlement proceeding to create a forum for capacity buyers and capacity suppliers to find common ground. The settlement discussions were not successful and have been terminated. On December 12, 2008, PJM filed tariff revisions with FERC to make important enhancements to the RPM rules in time for the May 2009 forward auction. PJM has requested an effective date of March 27, 2009 for its proposed tariff revisions.

PJM, like MISO, dispatches power plants to meet system energy and reliability needs, and settles physical power deliveries at LMPs. This value is determined by an ISO-administered auction process, which evaluates and selects the least costly supplier offers or bids to create reliable and least-cost dispatch. The ISO-sponsored LMP energy markets consist of two separate and characteristically distinct settlement time frames. The first is a security-constrained, financially firm, day-ahead unit commitment market. The second is a security-constrained, financially settled, real-time dispatch and balancing market. Prices paid in these LMP energy markets, however, are affected by, among other things, (i) market mitigation measures, which can result in lower prices associated with certain generating units that are mitigated because they are deemed to have the potential to exercise locational market power, and (ii) existing $1,000/MWh energy market price caps that are in place.

Contracted Capacity and Energy

MISO. Power prices are a significant driver of our financial performance due to the fact that a significant portion of our power generating capacity in the MISO is attributable to coal-fired baseload units. In MISO, we have entered into a mix of bilateral contracts and physical and financial over-the-counter energy sales for 2009 and 2010 with limited forward sales beyond 2010.

PJM. Our generation assets in PJM are either intermediate dispatch or peaking facilities. We commercialize these assets through a combination of bilateral sales and sales into the RPM auction. Additionally, approximately 280 MW of capacity at our Kendall facility is contracted under a tolling agreement through 2017.

Regulatory Considerations

In January 2006, the ICC approved a reverse power procurement auction as the process by which utilities would procure power beginning in 2007. The initial auction occurred in September 2006, and we subsequently entered into two supplier forward contracts with subsidiaries of Ameren to provide capacity, energy and related services. The Illinois legislature passed legislation in 2007 as part of the Illinois rate relief package that significantly altered the power procurement process in Illinois; but the contracts with the Ameren subsidiaries remain in effect.

In July 2007, legislative leaders in the State of Illinois announced a comprehensive transitional rate relief package for electric consumers. This program will provide approximately $1 billion to help provide assistance to utility customers in Illinois and fund a new power procurement agency. As part of this rate relief package, we will make payments of up to $25 million over a 29-month period. These payments will be contingent on certain conditions related to the absence of future electric rate and tax legislation in Illinois. We made payments of $7.5 million in 2007 and $9 million in 2008 and anticipate making a final payment of $8.5 million in 2009.

Construction Project

Plum Point. We own an approximate 37 percent interest in PPEA Holding Company LLC (PPEA), which, through its wholly owned subsidiary, owns an approximate 57 percent undivided interest in the Plum Point Energy Station (Plum Point), a 665 MW coal-fired power generation facility under construction in Mississippi County, Arkansas. Plum Point is currently expected to commence commercial operations by August 2010. All of PPEA s 378 MW have been contracted for an initial 30-year period. The PPAs provide for a pass-through of commodity, fuel, transportation and emissions expenses. The joint owners of Plum Point initially selected us as the construction manager of the project. However, on December 31, 2008, we gave notice of our intention to terminate an agreement under which we are acting as operator of Plum Point. It is anticipated that this agreement will be terminated effective on or before April 30, 2009. We have previously indicated that we consider Plum Point a non-core asset and intend to pursue alternatives regarding our remaining ownership interest.

Power Generation West Segment

Our West fleet is comprised of seven predominantly natural gas-fired power generation facilities, located in California (3), Arizona (2), Georgia (1) and Nevada (1), and one fuel oil-fired power generation facility, located in California, totaling 5,775 MW of electric generating capacity.

RTO/ISO Discussion

CAISO. CAISO covers approximately 90 percent of the state of California. At December 31, 2008, we owned four generating facilities in California with an aggregate net generating capacity of 4,050 MW within CAISO. The South Bay and Oakland facilities are designated as RMR units by the CAISO.

Southwest Region. The Southwest region covers Arizona, Nevada, Colorado, Utah and portions of New Mexico but is not formally structured as an RTO/ISO. At December 31, 2008, we owned two combined cycle generating facilities located in Arizona with an aggregate net generating capacity of 1,143 MW located within the Southwest region. Griffith is subject to WAPA control area requirements, while Arlington Valley is in a generation-only control area operated by Constellation Energy (Constellation).

SERC. The SERC Reliability Corporation is the regional entity covering a majority of the southeast states. At December 31, 2008, we owned one natural gas-fired peaking generation facility in Georgia with an aggregate net generating capacity of 539 MW located in the SERC area. SERC is the regional entity with delegated authority from NERC and is responsible for promoting, coordinating and ensuring the reliability and adequacy of the bulk power supply systems in the southeast region. On February 25, 2009, we entered into an agreement to sell our interest in the Heard County power generation facility to Oglethorpe Power Corporation. Subject to regulatory approval, the transaction is expected to close in the first half of 2009. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Heard County for further discussion.

Contracted Capacity and Energy

CAISO. In the CAISO region, where our assets include intermediate dispatch and peaking facilities, we seek to mitigate spark spread variability through RMR and tolling arrangements, as well as heat rate call options. To that end, all of the capacity of our Moss Landing units 6 and 7 and Morro Bay facility are contracted under tolling arrangements through 2010 and 2013, respectively. Our Oakland facility operates under an RMR contract from year to year. Our South Bay facility will also likely operate under an RMR contract upon completion of its current tolling arrangement at the end of 2009. With respect to Moss Landing units 1 and 2, we seek to mitigate our exposure to changes in the market price of energy through a financially-settled heat rate call-option on 750 MW through September 2010.

Southwest Region. In the Southwest region, we operate two intermediate dispatch facilities. Volumes generated by these facilities can vary significantly depending on changes in spark spreads. Therefore, we seek to manage this risk by entering into tolling arrangements. The full capacity of our Griffith facility is contracted under a summer tolling agreement from June through September through 2017. Additionally, we have entered into a summer tolling agreement for our Arlington Valley facility, which will be in place for June through September 2010 and 2011 and from May through October of 2012 through 2019.

Regulatory Considerations

CAISO. CAISO s proposal to implement MRTU has experienced numerous delays and is now expected to launch on March 31, 2009. MRTU is intended to improve management of California s transmission grid, provide clear rules for wholesale buyers and sellers and allow market prices to reflect actual costs.

On the state level, there are numerous other ongoing market initiatives that impact wholesale generation, principally the development of resource adequacy rules and capacity markets.

Equity Investment and Construction Project

Black Mountain. We have a 50 percent indirect ownership interest in the Black Mountain plant, which is a PURPA QF located near Las Vegas, Nevada, in the WECC. Capacity and energy from this facility are sold to Nevada Power Company under a long-term PURPA QF contract that runs to 2023.

Sandy Creek. SCH has a 50 percent ownership interest in SCEA, which owns an approximate 64 percent undivided interest in the Sandy Creek Energy Station, an 898 MW coal-fired power generation facility under construction in McLennan County, Texas. We anticipate commercial operations will begin in 2012. Of the expected plant output associated with SCEA s 64 percent undivided interest, 250 MW have been contracted for an initial 30-year period. The PPAs provide for a pass-through of commodity, fuel, transportation and emissions expenses. Similar contracts for additional output will be sought as plant construction proceeds. SCEA s share of the construction cost is being financed through project debt and equity. We have previously indicated that we consider Sandy Creek a non-core asset and intend to pursue alternatives regarding our remaining ownership interest.

Power Generation Northeast Segment

Our Northeast fleet is comprised of five facilities located in New York (3), Connecticut (1) and Maine (1), with a total capacity of 3,809 MW. We own and operate the Independence, Bridgeport, Casco Bay and Danskammer Units 1 and 2 power generating facilities, and we operate the Roseton and Danskammer Units 3 and 4 power generating facilities under long-term lease arrangements. Our Roseton and Danskammer facility sites are adjacent and share common resources such as fuel handling, a docking terminal, personnel and systems.

RTO/ISO Discussion

The Northeast region is characterized by two interconnected and actively traded competitive markets: the NYISO (an ISO) and the ISO-NE (an RTO). In the Northeast markets, load-serving entities generally lack their own generation capacity, with much of the generation base aging and the current ownership of the generation spread among several unaffiliated operators. Thus, commodity prices are more volatile on an as-delivered basis than in other regions due to the distance and occasional physical constraints that impact the delivery of fuel into the region.

Although both Northeast RTOs/ISOs and their respective energy markets are functionally, administratively and operationally independent, they follow, to a certain extent, similar market designs. Both the NYISO and the ISO-NE dispatch power plants to meet system energy and reliability needs and settle physical power deliveries at LMPs as discussed above. The energy markets in both the NYISO and ISO-NE also have defined, but different, mitigation protocols for bidding.

In addition to energy delivery, the NYISO and ISO-NE administer markets for installed capacity, ancillary services and FTRs.

NYISO. The NYISO market includes virtually the entire state of New York. At December 31, 2008, we operated three facilities in New York with an aggregate net generating capacity of 2,742 MW within NYISO. In 2003, NYISO implemented a Demand Curve mechanism for calculating the price and quantity of installed capacity to be procured statewide, with capacity prices determined for the two locational zones (New York City and Long Island), and for the New York Control Area at large. Our facilities operate outside of the New York City and Long Island locational zones.

Capacity pricing is calculated as a function of NYISO s annual required reserve margin, the estimated net cost of new entrant generation, estimated peak demand and the actual amount of capacity bid into the market at or below the Demand Curve. The Demand Curve mechanism provides for incrementally higher capacity pricing at lower reserve margins, such that new entrant economics become attractive as the reserve margin approaches required minimum levels. The intent 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 when that new capacity is needed.

Table of Contents

Due to transmission constraints, energy prices vary across New York 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 are somewhat above the NYISO s current required reserve margin of 15 percent. The New York State Reliability Council has filed a request with FERC to increase the required reserve margin for the May 1, 2009 to April 30, 2010 Capability Year to 16.5 percent.

ISO-NE. The ISO-NE market includes Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. As of December 31, 2008, we owned and operated two power generating facilities within the ISO-NE footprint one in Connecticut and one in Maine, with an aggregate net generating capacity of 1,067 MW within ISO-NE. ISO-NE is in the process of implementing a FCM.

Contracted Capacity and Energy

NYISO. We commercialize the majority of our assets by entering into a mix of bilateral contracts and both physical and financial over-the-counter energy sales for 2009 and 2010.

At our Independence facility, 740 MW of capacity is contracted under a capacity sales agreement that 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 and up to 44 MW of electric energy from our Independence facility to a third party at a fixed price.

For the uncommitted portion of our NYISO 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 remaining capacity into the market each month. This provides relatively stable capacity revenues at market prices from our facilities both in the short-term and for the foreseeable future.

ISO-NE. We receive monthly fixed transitional capacity payments for all of our 1,067 MW of ISO-NE generating capacity in accordance with the terms of the FCM settlement described below.

Regulatory Considerations

The ISO-NE is in the process of completing its implementation of FCM with capacity delivery under FCM starting in June 2010. The transitional payments for capacity commenced in December 2006 and run through May 31, 2010. The prices start at $3.05/KW-month and increase at defined intervals (discussed below) leading to an ending price of $4.10/KW-month. On June 1, 2010, capacity compensation will be determined through the FCM market. The first auction for the 2010/2011 Capacity Commitment Period (June 1, 2010 through May 31, 2011) was held in February 2008 and resulted in excess capacity remaining at the auction floor price of $4.50/kW-month. The second auction for the 2011/2012 Capacity Commitment Period (June 1, 2011 through May 31, 2012) was held in December 2008 and resulted in excess capacity remaining at the auction floor price of $3.60/kW-month. The third auction for the 2012/2013 Capacity Commitment Period (June 1, 2012 through May 31, 2012) will be held in October 2009. During the transition from the pre-existing capacity markets in ISO-NE to the FCM, all listed ICAP resources can receive monthly capacity payments at the relevant transition period rate up to its audited rating. Both of Dynegy s facilities in ISO-NE (i.e., Bridgeport and Casco Bay) are eligible to receive the transition payments and sell and be paid for their capacity under the FCM.

In New York, capacity pricing is calculated as a function of NYISO s annual required reserve margin, the estimated net cost of new entrant generation, estimated peak demand and the actual amount of capacity bid into the market at or below the Demand Curve.

Other

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, are included in Other in our segment reporting. Corporate general and administrative expenses, income taxes and interest expenses are also included, as are corporate-related other income and expense items. Results for our former CRM segment, which primarily consists of a minimal number of power and natural gas trading positions, are also included in this segment in prior periods where appropriate.

Table of Contents

ENVIRONMENTAL MATTERS

Our business is subject to extensive federal, state and local laws and regulations governing discharge of materials into the environment. We are committed to operating within these regulations and to conducting our business in an environmentally responsible manner. The environmental, legal and regulatory landscape is subject to change and has become more stringent over time. The process for acquiring or maintaining permits or otherwise complying with applicable rules and regulations may require unprofitable or unfavorable operating conditions or significant capital and operating expenditures. Failure to acquire or maintain permits or to otherwise comply with applicable rules and regulations may result in fines and penalties or negatively impact our ability to advance projects in a timely manner or at all. Interpretations of existing regulations may change, subjecting historical maintenance, repair and replacement activities at our facilities to claims of noncompliance.

Our aggregate expenditures (both capital and operating) for compliance with laws and regulations related to the protection of the environment were approximately $245 million in 2008 compared to approximately $108 million in 2007 and approximately $60 million in 2006. The 2008 expenditures include approximately $215 million for projects related to our Consent Decree (which is discussed below) compared to $71 million for Consent Decree projects in 2007. We estimate that total environmental expenditures in 2009 will be approximately $300 million, including approximately $280 million in capital expenditures and approximately $20 million in operating expenditures. Changes in environmental regulations or outcomes of litigation and administrative proceedings could result in additional requirements that would necessitate increased future spending and potentially adverse operating conditions. Please read Item 1. Business Environmental Matters and Note 19 Commitments and Contingencies for further discussion of this matter.

Climate Change

For the last several years, there has been an ongoing public debate about climate change, or global warming, and the need to reduce emissions of greenhouse gases (GHG), primarily CO_2 and methane emissions. While no federal legislation has been enacted to control GHG emissions, several state regulatory initiatives are being developed or implemented to reduce GHG emissions, as discussed below. Our position is that since climate change is a global issue, any regulation of GHG emission sources in the United States should be undertaken by the federal government in coordination with developed and developing countries around the world. We believe that the focus of any federal program addressing climate change should include three critical, interrelated elements: the environment, the economy and energy security.

Power generating facilities are a major source of CO_2 emissions in 2008, the facilities in our Midwest, West and Northeast segments emitted approximately 24.9 million, 5.2 million and 5.2 million tons of CO_2, respectively. The amounts of CO_2 emissions from our facilities during any time period will depend upon their dispatch rates during the period.

Recent court decisions and interpretations of the CAA by the U.S. EPA have added complexity to the national debate over the appropriate regulatory mechanisms for controlling and reducing CO_2 emissions. In April 2007, the U.S. Supreme Court issued its decision in *Massachusetts v. EPA*, involving the regulation of GHG emissions of motor vehicles. The Court ruled that GHGs meet the definition of a pollutant under the CAA and that regulation of GHG emissions is authorized by the CAA. The Court ruled that the U.S. EPA has a duty to determine whether or not GHG emissions may reasonably be anticipated to endanger public health or welfare within the meaning of the CAA. If the agency concludes that GHG emissions from new motor vehicles cause or contribute to a condition of air pollution that may reasonably be anticipated to endanger public health or welfare, then the agency would be required to set motor vehicle standards for GHG emissions. Regulation of GHG emissions from motor vehicles by the U.S. EPA following such a determination would likely lead to regulation of GHG emissions from stationary sources, such as power generating facilities, under other sections of the CAA. In response to the *Massachusetts v. EPA* decision, the U.S. EPA issued an ANPR in July 2008 discussing potential regulation of GHG emissions under the CAA. The ANPR discusses each section of the CAA that applies to stationary sources, such as power generating facilities, and the complexities associated with regulating GHG emissions under these existing statutory provisions, which were designed to address more localized environmental matters. The agency expressed the view that it is not desirable to regulate GHG emissions using a law designed for very different environmental challenges, and solicited comments from the public on whether or not well-designed legislation for establishing a GHG regulatory framework would be more appropriate than regulation under the CAA. The comment period on the ANPR closed in November 2008; no endangerment finding has yet been made by the U.S. EPA.

On December 2, 2008, EAB issued its opinion in *In re: Deseret Power Electric Cooperative*, an appeal from the grant of a construction permit under the PSD program. The EAB held that the CAA does not dictate whether U.S. EPA must apply BACT for the control of CO_2 emissions in PSD permits. Moreover, the EAB ruled that U.S. EPA has discretion to interpret the CAA on this point, and it remanded the case to the U.S. EPA for reconsideration. On December 18, 2008, the U.S. EPA Administrator Johnson sent a memorandum (the Johnson Memorandum) to the agency s regional administrators setting forth the agency s interpretation that pollutants subject to PSD requirements exclude those pollutants for which EPA regulations only require monitoring and reporting of emissions, but include those pollutants subject to either a provision of the CAA or a regulation promulgated by the U.S. EPA under the CAA that requires actual control of emissions. Since neither the CAA nor agency regulations control CO_2 emissions under the Administrator s interpretation CO_2 would not be considered subject to PSD requirements, including BACT. On January 15, 2009, several environmental groups filed suit challenging the interpretive memorandum in the U.S. Court of Appeals for the D.C. Circuit. With the change in administration following the Presidential election, many interpretations of environmental laws and regulations by the former administration are being reevaluated. On February 17, 2009 the new Administrator of U.S. EPA granted the petition of environmental groups to reconsider the Johnson Memorandum.

The adoption of regulatory programs mandating a substantial reduction in CO_2 emissions or attaching a significant cost to those emissions could have a far-reaching and significant impact on us and others in the power generating industry. Several bills have been introduced in Congress that would compel reductions in CO_2 emissions from power plants. However, we believe it is not likely that any mandatory federal CO_2 emissions reduction program will be adopted and implemented in the immediate future, and the specific requirements of any such program cannot be predicted with confidence. Various states in which we have generating facilities have proposed, are in the process of developing or have implemented, regulatory programs to reduce CO_2 emissions. Officials in other states where we have generation assets have expressed the intent to reduce CO_2 emissions We are closely following and continually analyzing legislative and regulatory developments in these jurisdictions to determine how such developments might impact our business.

Midwest. Our assets in Illinois and Michigan may become subject to a regional GHG cap and trade program being developed under the MGGA. The MGGA is an agreement among the states of Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin and the Province of Manitoba to create a MGGRP to establish GHG reduction targets and timeframes consistent with member states targets and to develop a market-based and multi-sector cap and trade mechanism to achieve the GHG reduction targets.

Illinois has set a goal of reducing GHG emissions to 1990 levels by the year 2020, and to 60 percent below 1990 levels by 2050. The Michigan Climate Action Council has recommended to the governor a goal of reducing GHG emissions by 80 percent below 2002 levels by 2050.

The MGGRP is still in an early stage of development and specific targets for GHG emission reductions and regulations to achieve such targets have not yet been developed. While any mandatory GHG reduction required of existing generators would affect our generation fleet, the nature and extent of such effects cannot be confidently predicted at this time.

West. Our assets in California will be subject to various state initiatives. The California Global Warming Solutions Act, which became effective in January 2007, requires development of a GHG emission control program that will reduce emissions of GHG in the state to their 1990 levels by 2020. The program has established a statewide GHG emissions cap of 427 million metric tons beginning in 2020. Regulations required to achieve emission reductions necessary to meet the 2020 GHG emissions cap will be due by January 2011, and implementation and enforcement of the regulatory program must be in place by January 2012. California state law also requires establishment of GHG emission performance standards for publicly owned utilities and municipalities. Proceedings have commenced to establish such performance standards, restricting the rate of GHG emissions from baseload generators to that of combined-cycle natural gas baseload generation.

Our assets in Arizona will likely become subject to regulatory controls initiated by the state. The governor of Arizona has established a statewide goal of reducing GHG emissions to 2000 levels by 2020, and to 50 percent below 2000 levels by 2040.

Our assets in California and Arizona will likely become subject to a regional GHG cap and trade program being developed under the WCI. The WCI is a collaborative effort of seven states and four Canadian provinces to reduce GHG emissions in the participating jurisdictions. The WCI participants include Arizona, California, Montana, New Mexico, Oregon, Utah and Washington as well as the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. It has a regional goal of reducing GHG emissions to 15 percent below 2005 levels by 2020. The WCI has recommended a multi-sector cap and trade program that would include power generation facilities such as ours. The cap and trade program of the WCI is scheduled to be launched on January 1, 2012. Electric power generation facilities in Arizona and California would become subject to the cap and trade program at that time.

The WCI is still in the early stages of development and specific targets for GHG emission reduction have not yet been finalized. Any mandatory GHG reduction by existing generators under these programs would affect our generation fleet. However, the nature and extent of such effects cannot be confidently predicted at this time.

Northeast. Our assets in New York, Connecticut and Maine are already subject to a state-driven GHG emission control program known as RGGI beginning in 2009. RGGI is a program that has been developed and implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states developed a model rule for regulating GHG using a cap and trade program to reduce CO_2 emissions by at least 10 percent of 2009 emission levels by the year 2018.

The State of Maine s RGGI rules call for a CO_2 cap and trade program, capping total authorized CO_2 emissions from affected Maine power generation units larger than 25 MW beginning in 2009. Beginning in 2015, the CO_2 emission cap will be reduced each year until 2018. The proposed rules require that each affected power generator hold CO_2 allowances equal to its annual CO_2 emissions. Compliance with the allowance requirement may be achieved by reducing emissions, purchasing allowances or securing offset allowances from an approved offset project. Allowances are distributed to power generators through multi-state auctions with the proceeds to be used for energy efficiency and other GHG emission reduction projects and for ratepayer relief.

The State of New York s RGGI program established a cap and trade program capping total authorized CO_2 emissions from New York electric generators with capacity greater than 25 MW of electrical output. The initial CO_2 emissions cap for affected New York generators commences in 2009, beginning in 2015 the cap would be reduced each year until 2018. The program requires that each affected facility hold CO_2 allowances equal to the total CO_2 emissions from all of its affected units for the control period. Compliance with the allowance requirement may be achieved by reducing emissions, purchasing allowances or securing offset allowances from an approved offset project. All allowances are to be distributed through multi-state auctions open to participation by any individual or entity that meets prescribed minimum financial requirements. The auction proceeds are to be used to promote energy efficiency and clean energy technologies and to cover the administrative costs of the program.

The State of Connecticut also enacted legislation in June 2008 that mandates a cap and trade program for CO_2, including a requirement that affected generators purchase 100 percent of the CO_2 allowances needed to operate their facilities through an auction process.

The states of Connecticut, Maine, Maryland, Massachusetts, Rhode Island and Vermont sold CO_2 allowances for 2009 in the first RGGI CO_2 emissions allowance auction held on September 25, 2008. Over 12 million allowances were sold at the clearing price of $3.07 per allowance. On December 17, 2008, RGGI held the second auction and this time, all RGGI states, including New York, sold CO_2 allowances for the control period. Over 31 million credits offered were purchased at the clearing price of $3.38 per allowance. We participated in both RGGI auctions, purchasing a portion of the allowances required to cover our projected GHG emissions in the Northeast for 2009. Auctions are expected to be held quarterly with the next one scheduled for March 18, 2009.

Table of Contents

Assuming that 2009 CO_2 emissions from our generating facilities in New York, Maine and Connecticut are comparable to 2008 CO_2 emissions from these facilities (5.2 million tons), our estimated cost of allowances necessary to operate these facilities in 2009 would be about $17 million, based on the average cost of allowances purchased to date for the 2009 allocation year. We expect these increased costs to be at least partially reflected in future market prices.

On January 29, 2009, Indeck Corinth, L.P., owner of the Corinth Generating Station in New York, filed suit in state court challenging the authority of the New York Department of Environmental Conservation and the New York State Energy Research and Development Authority to implement the New York cap and trade program under RGGI without specific authorization from the New York Legislature. If successful, the suit could delay or prevent New York s participation in the RGGI program.

Climate Change Litigation. There is a risk of litigation seeking to impose liability or injunctive relief against sources of CO_2 emissions, including power generators, for claims of adverse effects due to climate change. At least four lawsuits have been filed seeking damages and/or injunctive relief based on claims that the plaintiffs have been adversely affected by climate change resulting from defendants GHG emissions. Three of the suits have been dismissed and appeals of their dismissals are pending in the U.S. Courts of Appeal for the Second, Fifth and Ninth Circuits. The fourth lawsuit is pending in the U.S. District Court for the Northern District of California. Please read Note 19 Commitments and Contingencies for further discussion of this matter.

Carbon Initiatives. We participate in several programs that partially offset or mitigate our CO_2 emissions. In the lower Mississippi River Valley, we have partnered with the U.S. Fish & Wildlife Service to restore more than 45,000 acres of bottomland forests by planting more than 2 million bottomland hardwood seedlings. In California, we are evaluating the use of bio-fuels as a means of reducing reliance on traditional fuels. At our Bridgeport facility, we are currently experimenting with running a plant on recovered methane. In Illinois, we are funding prairie, bottomland hardwood and savannah restoration projects in partnership with the Nature Conservancy. We also have a program to reuse ash produced at our coal-fired generation units through agreements with cement manufacturers that incorporate the material into cement products.

Through memberships in organizations such as the Edison Electric Institute and the Electric Power Research Institute, we participate in research aimed at reducing or mitigating emissions of CO_2 from electric power generation.

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 U.S. EPA finalized several rules that would collectively require reductions of approximately 70 percent each in emissions of SO_2, NO_x and mercury from coal-fired power generation units by 2015 (2018 for mercury).

CAIR, which is intended to reduce SO_2 and NO_x emissions from power generation sources across the eastern United States (29 states and the District of Columbia) and address fine particulate matter and ground-level ozone National Ambient Air Quality Standards, was issued as a final rule in April 2006. Numerous environmental groups, industry representatives and State governments challenged the CAIR rule in the U.S. Court of Appeals for the District of Columbia Circuit. On July 11, 2008, the court issued its decision vacating the CAIR in its entirety. On September 24, 2008, the U.S. EPA filed a petition for rehearing, or alternatively for remand of the case without vacatur. On December 23, 2008, the Court granted the U.S. EPA s petition, remanding the case without vacatur for the U.S. EPA to conduct further proceedings consistent with the court s decision of July 11, 2008. As a result, the substantive requirements of CAIR will remain effective until the U.S. EPA completes further rulemaking. Our facilities in Illinois and New York are subject to state SO_2 and NO_x limitations more stringent that those imposed by CAIR.

Table of Contents

In March 2005, the U.S. EPA issued the CAMR for control of mercury emissions from coal-fired power plants in March 2005 and established a cap and trade program requiring states to promulgate rules at least as stringent as CAMR. In December 2006, the Illinois Pollution Control Board approved a state rule for the control of mercury emissions from coal-fired power plants that required additional capital and O&M expenditures at each of our Illinois coal-fired plants beginning in 2007. The State of New York has also approved a mercury rule that will likely require us to incur additional capital and operating costs. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAMR; however, the Illinois and New York mercury regulations remain in effect.
CAVR requires states to analyze and include BART requirements for individual facilities in their SIPs to address regional haze. 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 would result in more visibility improvements than BART would provide. The state rules were due by the end of 2008 with compliance expected five years later. Since several states, including Illinois and New York, failed to meet the deadline for issuing BART rules, the U.S. EPA will promulgate standards through a FIP to accomplish the CAVR goals. States that do not complete their rulemaking before the FIP is finalized will become subject to the FIP standards.

The Clean Air Act

The CAA 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 CAA requires that fossil-fueled plants have sufficient emission allowances to cover actual SO_2 emissions and in some regions NO_X, emissions, and that they meet certain pollutant emission standards as well. Our generation facilities, some of which have changed their operations to accommodate new control equipment or changes in fuel mix, are presently in compliance with these requirements. In order to ensure continued compliance with the CAA and related rules and regulations, including ozone-related requirements, we have plans to install emission reduction technology. We expect to incur total capital expenditures of up to $25 million in 2009 pursuant to such plans.
SCEA received a construction permit for the Sandy Creek Project from the TCEQ in July 2006. Opponents of the project filed an appeal in state district court, and the court affirmed the decision of the TCEQ on March 29, 2007. The petitioners further appealed the decision to the state court of appeals, which affirmed the TCEQ and district court decisions on January 29, 2009. The petitioners may seek review of the decision before the Texas Supreme Court.
Following the vacatur of the CAMR by the United States Court of Appeals for the D.C. Circuit, two environmental groups filed suit against SCEA in the U.S. District Court for the Western District of Texas. The plaintiffs claim that the Sandy Creek Project failed to obtain a determination of the MACT for the control of hazardous air pollutants before beginning construction in January 2008. We filed a motion to dismiss on September 9, 2008 and briefing is complete. We expect a ruling on the motion in early 2009. We believe that the lawsuit lacks merit and are vigorously defending against its claims.
In 2005, we settled a lawsuit filed by the U.S. EPA and the U.S. Department of Justice in the U.S. District Court for the Southern District of Illinois that alleged violations of the CAA and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating station. A Consent Decree was finalized in July 2005 which would prohibit operation of certain of our power generating facilities after specified dates unless certain emission control equipment is installed. We plan to install the required emission control equipment to allow continued operations. We anticipate our costs associated with the Consent Decree projects, which we expect to incur through 2012, will be approximately $960 million, which includes approximately $290 million spent to date. This estimate required a number of assumptions about uncertainties that are beyond our control. For instance, we have assumed for purposes of this estimate that labor and material costs will increase at four percent per year over the remaining project term. The following are the future estimated capital expenditures required to comply with the Consent Decree:

2009	2010	2011	2012
(in millions)			

$	245	$	215	$	165	$	45

If the costs of these capital expenditures become great enough to render the operation of the affected facility or facilities uneconomical, we could, at our option, cease to operate the facility or facilities and forego these capital expenditures without incurring any further obligations under the Consent Decree.

Table of Contents

Water Issues

Our water withdrawals and wastewater discharges are permitted under the Clean Water Act and analogous state laws. Section 316(b) of the Clean Water Act and comparable state water laws and regulations require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact. Our cooling water intake structures at steam generating plants are subject to this requirement. The U.S. EPA issued rules (the Section 316(b) Phase II rules) in July 2004 establishing national standards aimed at protecting aquatic life at power generating facilities with existing cooling water intake structures. The Phase II rules were challenged by several environmental groups in the U.S. Court of Appeals for the Second Circuit.

In January 2007, the United States Court of Appeals for the Second Circuit remanded key provisions of the rules, including the U.S. EPA s determination of BTA for existing water intake structures, to the U.S. EPA for further rulemaking. The remand of the rules to the U.S. EPA created uncertainty concerning the performance standard and the schedule for implementing the requirement. The U.S. EPA suspended its Section 316(b) Phase II Rules in July 2007. In suspending the rules, the U.S. EPA advised that permit requirements for cooling water intake structures at existing facilities should be established on a case-by-case best professional judgment basis. The U.S. Supreme Court has granted certiorari to review whether Section 316(b) allows consideration of a cost-benefit comparison in determining BTA for a water intake structure. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is expected in 2009. The scope of requirements and the compliance methodologies that will ultimately be allowed by future rulemaking may become more restrictive, resulting in potentially significantly increased costs. In addition, the timing for compliance may be adjusted.

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

We are currently involved in an administrative proceeding in the State of New York to renew the SPDES permit governing the cooling water intake structure at our Roseton facility. The petitioner claims that the renewed permit must require closed cycle cooling to meet the BTA requirements of Section 316(b) of the Clean Water Act. Please read Note 19 Commitments and Contingencies Legal Proceedings Roseton State Pollutant Discharge Elimination System Permit for further discussion of this matter.

In 2006, we successfully completed similar administrative proceedings concerning our Danskammer facility resulting in a new SPDES permit. The issuance of the new Danskammer SPDES permit was appealed to the New York Supreme Court, Appellate Division, which dismissed the appeal. The appellants then filed a motion for leave to appeal the case to the New York Court of Appeals. On January 22, 2009, the New York Court of Appeals denied the appellants motion for leave to appeal the case. Please read Note 19 Commitments and Contingencies Legal Proceedings Danskammer State Pollutant Discharge Elimination System Permit for further discussion of this matter.

The issuance of a NPDES permit for the cooling water intake structure at our Moss Landing facility in California was recently upheld on appeal by the California Court of Appeals. On March 19, 2008, the Supreme Court of California granted review of the Court of Appeals decision. While we cannot predict the outcome of any such permit appeal, a ruling adverse to Moss Landing could result in material capital expenditures or reduced plant operations. Please read Note 19 Commitments and Contingencies Legal Proceedings Moss Landing National Pollutant Discharge Elimination System Permit, respectively, for further discussion of this matter.

A decision to install a closed cycle cooling system at any of our facilities, including the Danskammer, Roseton or Moss Landing facilities, would be made on a case-by-case basis considering all relevant factors at such time, including any relevant costs or applicable remediation requirements. If mandated installation of closed cycle cooling systems at any of these facilities would result in a material capital expenditure that renders the operation of a plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such facility and forego these capital expenditures.

Remedial Laws

We are 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 for contributions to the release of a hazardous substance into the environment. Those with potential liabilities include the current or previous owner and operator of a facility and companies that disposed, or arranged for disposal, of hazardous substances found at a contaminated facility. CERCLA also authorizes the U.S. EPA and, in some cases, private parties to take actions in response to threats to public health or the environment and to seek recovery for costs of cleaning up hazardous substances that have been released and for damages to natural resources from responsible parties. Further, it is not uncommon for neighboring landowners and other affected parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. CERCLA or RCRA could impose remedial obligations with respect to a variety of our facilities and operations.

The U.S. EPA may develop new regulations, and Congress may pass new legislation, that imposes additional requirements on facilities that store or dispose of non-hazardous fossil fuel combustion materials, including coal ash. If so, we 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. Please read Note 2 Summary of Significant Accounting Policies Asset Retirement Obligations for further discussion.

COMPETITION

Demand for power may be met by generation capacity based on several competing generation technologies, such as natural gas-fired, coal-fired or nuclear generation, as well as power generating facilities fueled by alternative energy sources, including hydro power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Our power generation businesses in the Midwest, West and Northeast compete with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies and financial institutions. 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. Our ability to compete effectively will also be impacted by various governmental and regulatory activities designed to reduce GHG emissions and to support the construction and operation of renewables-fueled power generation facilities. We believe our primary competitors consist of at least 20 companies in the power generation business.

Table of Contents

OPERATIONAL RISKS AND INSURANCE

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

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

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

SIGNIFICANT CUSTOMERS

For the year ended December 31, 2008, approximately 25 percent and 11 percent of our consolidated revenues were derived from transactions with MISO and NYISO, respectively. For the year ended December 31, 2007, approximately 23 percent, 17 percent and 11 percent of our consolidated revenues were derived from transactions with MISO, NYISO and Ameren, respectively. For the year ended December 31, 2006, approximately 23 percent, 19 percent and 18 percent of our consolidated revenues were derived from transactions with Ameren, MISO and NYISO, respectively. No other customer accounted for more than 10 percent of our consolidated revenues during 2008, 2007 or 2006.

EMPLOYEES

At December 31, 2008, we had approximately 700 employees at our corporate headquarters and field-based administrative offices and approximately 1,300 employees at our operating facilities. Approximately 800 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions that expire in August 2010, June 2011 and January 2012. We believe relations with our employees are satisfactory.

Table of Contents

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 and other words of similar meaning. In particular, these i are not limited to, statements relating to the following:

- beliefs about commodity pricing and generation volumes;
- beliefs regarding the current economic downturn, its trajectory and its impacts;
- sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation;
- beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale power generation market;
- beliefs associated with Dynegy s market capitalization and its impact on goodwill;
- strategies to capture opportunities presented by changes in commodity prices and to manage our exposure to energy price volatility;
- beliefs and assumptions about weather and general economic conditions;
- expectations regarding environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations, including those relating to climate change;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- beliefs and assumptions regarding the current financial crisis and its impact on our liquidity needs and on the credit markets generally and our access thereto;
- beliefs and assumptions relating to liquidity and capital resources generally;
- beliefs and expectations regarding financing, development and timing of the Sandy Creek and Plum Point projects;
- expectations regarding capital expenditures, interest expense and other payments;
- our focus on safety and our ability to efficiently operate our assets so as to maximize our revenue generating opportunities and operating margins;
- beliefs about the outcome of legal, regulatory, administrative and legislative matters;
- expectations and estimates regarding capital and maintenance expenditures, including the Consent Decree and its associated costs; and
- efforts to position our power generation business for future growth and pursuing and executing acquisition, disposition or combination opportunities.

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.

Table of Contents

FACTORS THAT MAY AFFECT FUTURE RESULTS

Risks Related to the Operation of Our Business

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

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

Because we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other power markets on a term basis, we are not guaranteed any rate of return on our capital investments. Rather, our financial condition, results of operations and cash flows will 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. Such factors that may materially impact the power markets and our financial results are:

- the current and continuing economic downturn, the existence and effectiveness of demand-side management and conservation efforts and the extent to which they impact electricity demand;
- regulatory constraints on pricing (current or future);
- fuel price volatility; and
- increased competition or price pressure driven by generation from renewable sources.

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

Our commercial strategy may result in lost opportunities and, in any case, may not be executed as planned.

We seek to commercialize our assets through sales arrangements of various tenors. In doing so, we attempt to balance a desire for greater certainty of earnings and cash flows in the near term with a belief that commodity prices will rise over the longer term, creating upside opportunities for those with open merchant length. Our ability to successfully execute this strategy is dependent on a number of factors, many of which are outside our control, including market liquidity, the availability of counterparties willing to transact at prices we believe are commercially acceptable and the people and systems comprising our commercial operations function. If we are unable to transact in the near term, our near-term financial condition, results of operations and cash flows will be subject to significant uncertainty and volatility. Alternatively, significant near-term contract execution may precede a run-up in commodity prices, resulting in lost upside opportunities and mark-to-market accounting losses effecting significant variability in net income and other GAAP reported measures.

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 fuel oil supply agreements.

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

Table of Contents

Moreover, 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. In particular, we have entered into term contracts for South American coal, which we use for our GEN-NE coal assets. We cannot assure you that we will be able to renew these contracts when they terminate on terms that are favorable to us or at all. Further, transportation of South American coal is subject to local political and other factors that could have a negative impact on our coal deliveries regardless of our contract situation. Permit limitations associated with the loading and unloading of coal at our GEN-NE coal facility limit our options for coal fuel supply and, when coupled with continued strong coal prices and uncertainties associated with international contracting, create continuing risk for us in terms of our ability to procure coal for periods and at prices we believe are firm and favorable.

Further, any changes in the costs of coal, fuel oil, natural gas or transportation rates of the commodity and changes in the relationship between such costs and the market prices of power will affect our financial results and our ability to recover those costs. 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.

Our costs of compliance with existing environmental requirements are significant, and costs of compliance with new environmental requirements 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, transportation, treatment, storage and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances (including CO_2) into the environment, and in connection with environmental impacts associated with cooling water intake structures. Existing environmental laws and regulations may be revised or reinterpreted, new laws and regulations may be adopted or may become applicable to us or our facilities, and litigation or enforcement proceedings could be commenced against us. Proposals being considered by federal and state authorities (including proposals regarding climate change regulation) could, if and when adopted or enacted, require us to make substantial capital and operating expenditures. If any of these events occur, our financial condition, results of operations and cash flows could be materially adversely affected.

Moreover, many environmental laws require approvals or permits from governmental authorities before construction, modification or operation of a power generation facility may commence. Certain environmental permits must be renewed periodically in order to continue operating our facilities. The process for obtaining and renewing necessary permits can be lengthy and complex and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures. We are required to comply with numerous environmental laws and regulations, and to obtain numerous governmental permits when we construct, modify and operate our facilities. If there is a delay in obtaining any required environmental regulatory approvals or permits, if we fail to obtain any required approval or permit, or if we are unable to comply with the terms of such approvals or permits, the operation of our facilities may be interrupted or become subject to additional costs. Further, interpretations of existing regulations may change, subjecting historical maintenance, repair and replacement activities at our facilities to claims of noncompliance. As a result, our financial condition, results of operations and cash flows could be materially adversely affected. Certain of our facilities are also required to comply with the terms of consent decrees or other governmental orders.

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

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

We are subject to extensive federal, state and local laws and regulations governing the generation and sale of energy commodities in each of the jurisdictions in which we have operations. Compliance with these ever-changing laws and regulations requires expenses (including legal representation) and monitoring, capital and operating expenditures. Potential changes in laws and regulations that could have a material impact on our business include: re-regulation of the power industry in markets in which we conduct business; the introduction, or reintroduction, of rate caps or pricing constraints; or a variation of these. Furthermore, these and other market-based rules and regulations are subject to change at any time, and we cannot predict what changes may occur in the future or how such changes might affect any facet of our business.

The costs and burdens associated with complying with the increased number of regulations may have a material adverse effect on us, if we fail to comply with the laws and regulations governing our business or if we fail to maintain or obtain advantageous regulatory authorizations and exemptions. Moreover, increased competition within the sector resulting from potential legislative changes, regulatory changes or other factors may create greater risks to the stability of our power generation earnings and cash flows generally.

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

We are required to maintain, either through allocation or purchase, sufficient emission allowances to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet our obligations imposed by various applicable environmental laws, with respect to which the trend toward more stringent regulations (including regulations currently proposed or being discussed regarding CO_2 emissions) will likely require us to obtain new or additional emission allowances. If our operational needs require more than our allocated quantity of emission allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances, or install costly new emissions controls. As we use the emissions allowances that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such allowances are available for purchase, but only at significantly higher prices, their purchase could materially increase our costs of operations in the affected markets and materially adversely affect our financial condition, results of operations and cash flows.

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

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

We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Electric 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, certain of our current facilities are relatively old. Newer plants owned by competitors will often be more efficient than some of our plants, which may put some of our plants at a competitive disadvantage. Over time, some of our plants may become obsolete in their markets, or be unable to compete, because of the construction of new, more efficient plants.

22

Table of Contents

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

Moreover, many companies in the regulated utility industry, with which the wholesale power industry is closely linked, are also restructuring or reviewing their strategies. Several of those companies have discontinued or are discontinuing their unregulated activities and seeking to divest or spin-off their unregulated subsidiaries. Some of those companies have had, or are attempting to have, their regulated subsidiaries acquire assets out of their or other companies unregulated subsidiaries. This may lead to increased competition between the regulated utilities and the unregulated power producers within certain markets. To the extent that competition increases, our financial condition, results of operations and cash flows may be materially adversely affected.

We do not own or control transmission facilities required to sell the wholesale power from our generation facilities. If the transmission service is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. Furthermore, these transmission facilities are operated by RTOs and ISOs , which are subject to changes in structure and operation and impose various pricing limitations. These changes and pricing limitations may affect our ability to deliver power to the market that would, in turn, adversely affect the profitability of our generation facilities.

We do not own or control the transmission facilities required to sell the wholesale power from our generation facilities. If the transmission service from these facilities is unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. RTOs and ISOs provide transmission services, administer transparent and competitive power markets and maintain system reliability. Many of these RTOs and ISOs operate in the real-time and day-ahead markets in which we sell energy. The RTOs and ISOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, offer caps and other mechanisms to guard against the potential exercise of market power in these markets as well as price limitations. These types of price limitations and other regulatory mechanisms may adversely affect the profitability of our generation facilities that sell energy and capacity into the wholesale power markets. 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 also 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. Additionally, if the transmission service from these facilities is unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. Furthermore, the rates for transmission capacity from these facilities are set by others and thus are subject to changes, some of which could be significant, and as a result, our financial condition, results of operations and cash flows may be materially adversely affected.

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

A majority of the employees at our facilities are subject to collective bargaining agreements with various unions that expire from 2010 through 2012. Employees at our Griffith facility in Arizona have voted for union certification, and we are currently engaged in discussions with their representatives regarding a collective bargaining agreement. Similar unionization activities could occur at other generating facilities in our fleet. If union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor is uncertain. Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms could have a material adverse effect on our financial condition, results of operations and cash flows.

Costs of compliance with our Consent Decree may be materially adversely impacted by unforeseen labor, material and equipment costs.

As a result of the Consent Decree, we are required to not operate certain of our most profitable power generating facilities after specified dates unless certain emission control equipment is installed. We have incurred significant costs in complying with the Consent Decree and anticipate incurring additional significant costs over the course of the next four years. We are exposed to the risk of substantial price increases in the costs of materials, labor and equipment used in the construction. We are further exposed to risk in that counterparties to the projects may fail to perform, in which case we would be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and possibly cause delays to the project timelines. If the costs of these capital expenditures become great enough to render the operation of the facility uneconomical, we could, at our option, cease to operate the facility or facilities and forego these capital expenditures without incurring any further obligations under the Consent Decree.

Risks Related to Our Financial Structure, Level of Indebtedness and Access to Capital Markets

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

We acquired the DNE power generating facilities in January 2001 for $950 million. In May 2001, we entered into an asset-backed sale-leaseback transaction relating to these facilities to provide us with long-term acquisition financing. In this transaction, we sold four of the six generating units comprising these facilities for approximately $920 million to Danskammer OL LLC and Roseton OL LLC, and we concurrently agreed to lease them back from these entities. We have no option to purchase the leased facilities at Roseton or Danskammer at the end of their lease terms, which end in 2035 and 2031, respectively. If one or more of the leases were to be terminated prior to the end of its term because of an event of loss (such as substantial damage to a facility or a condemnation or similar governmental taking or action), because it becomes illegal for us to comply with the lease, or because a change in law makes the facility economically or technologically obsolete, we would be required to make a termination payment in an amount sufficient to compensate the lessor for termination of the lease, including redeeming the pass-through trust certificates related to the unit or facility for which the lease is terminated. As of December 31, 2008, the termination payment would be approximately $930 million for all of our DNE facilities. It could be difficult for us to raise sufficient funds to make this termination payment if a termination of this type were to occur with respect to the DNE facilities, resulting in a material adverse effect on our financial condition, results of operations and cash flows.

We have significant debt that could negatively impact our business.

We have and will continue to have a significant amount of debt outstanding. As of December 31, 2008, we had total consolidated debt of approximately $6 billion. Our significant level of debt could:

- make it difficult to satisfy our financial obligations;
- limit our ability to obtain additional financing;
- 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;
- impact our ability to participate in industry consolidation; and
- increase our vulnerability to general adverse economic and industry conditions.

Furthermore, we may incur or assume additional debt 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.

Our financing agreements governing our debt obligations require us to meet specific financial tests. Our failure to comply with those financial covenants could have a material adverse impact on our business, financial condition, results of operations or cash flows.

Our financing agreements, including the Fifth Amended and Restated Credit Facility, as amended, have terms that 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. The agreements governing our debt obligations require us to meet specific financial tests both as a matter of course and as a precondition to the incurrence of additional debt and to the making of restricted payments or asset sales, among other things. Our obligations relating to ongoing financial tests include the maintenance of specified financial ratios regarding Secured Debt to EBITDA and EBITDA to Consolidated Interest Expense (as each such term is defined in the Fifth Amended and Restated Credit Facility). The financial tests set forth as a precondition to the events described above include the demonstration, on a pro forma basis, of a specified ratio of Total Indebtedness to EBITDA (as each such term is defined in the Fifth Amended and Restated Credit Facility). Any additional long-term debt that we may enter into in the future may also contain similar restrictions.

Our ability to comply with the financial tests and other 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, causing our debt obligations under such financing agreements (and by reason of cross-default or cross-acceleration provisions, our other indebtedness) to become immediately due and payable, which could have a material adverse impact on our business, financial condition, results of operations or cash flows. If those lenders accelerate the payment of such indebtedness, we cannot assure you that we could pay off or refinance that indebtedness immediately and continue to operate our business. If we are unable to repay those amounts, otherwise cure the default, or obtain replacement financing, the holders of the indebtedness under our secured debt obligations would be entitled to foreclose on, and acquire control of substantially all of our assets, which would have a material adverse impact on our financial condition, results of operations and cash flows.

Our access to the capital markets may be limited.

We may require additional capital from time to time. Because of our non-investment grade credit rating and/or general conditions in the financial and credit markets, our access to the capital markets may be limited. Moreover, the timing of any capital-raising transaction may be impacted by unforeseen events, such as legal or regulatory requirements, which could require us to pursue additional capital at an inopportune time. Our ability to obtain capital and the costs of such capital are dependent on numerous factors, including:

- general economic and capital market conditions, including the timing and magnitude of market recovery;
- covenants in our existing debt and credit agreements;
- investor confidence in us and the regional wholesale power markets;
- our financial performance and the financial performance of our subsidiaries;
- our levels of debt;
- our requirements for posting collateral under various commercial agreements;
- our credit ratings;
- our cash flow; and
- our long-term business prospects.

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

Table of Contents

Our non-investment grade status may adversely impact our operations, increase our liquidity requirements and increase the cost of refinancing opportunities. We may not have adequate liquidity to post required amounts of additional collateral.

Our credit ratings are currently below investment grade. We cannot assure you that our credit ratings will improve, or that they will not decline, in the future. Our credit ratings may affect the evaluation of our creditworthiness by trading counterparties and lenders, which could put us at a disadvantage to competitors with higher or investment grade ratings.

In carrying out our commercial business strategy, our current non-investment grade credit ratings have resulted and will likely continue to result in requirements that we either prepay obligations or post significant amounts of collateral to support our business. Various commodity trading counterparties make collateral demands that reflect our non-investment grade credit ratings, the counterparties views of our creditworthiness, as well as changes in commodity prices. We use a portion of our capital resources, in the form of cash, lien capacity, and letters of credit, to satisfy these counterparty collateral demands. Our commodity agreements are tied to market pricing and may require us to post additional collateral under certain circumstances. If market conditions change such that counterparties are entitled to additional collateral, our liquidity could be strained and may have a material adverse effect on our financial condition, results of operations and cash flows. 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.

Additionally, our non-investment grade credit ratings may limit our ability to refinance our debt obligations and to access the capital markets at the lower borrowing costs that would presumably be available to competitors with higher or investment grade ratings. 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.

We conduct a substantial portion of our operations through our subsidiaries and may be limited in our ability to access funds from these subsidiaries to service our debt.

We conduct a substantial portion of our operations through our subsidiaries and depend to a large degree upon dividends and other intercompany transfers of funds from our subsidiaries to meet our debt service and other obligations. In addition, the ability of our subsidiaries to pay dividends and make other payments to us may be restricted by, among other things, applicable corporate and other laws, potentially adverse tax consequences and agreements of our subsidiaries. If we are unable to access the cash flow of our subsidiaries, we may have difficulty meeting our debt obligations.

Risks Related to Investing

If our goodwill or amortizable intangible assets become impaired, we may be required to record a significant charge to earnings.

We have significant intangible assets and goodwill recorded on our balance sheet. In accordance with GAAP, we review our intangible assets for impairment when events or changes in circumstances indicate the carrying value may not be recoverable. Goodwill is required to be tested for impairment at least annually. Factors that may be considered are a change in circumstances indicating that the carrying value of our goodwill or intangible assets may not be recoverable including a decline in future cash flows and slower growth rates in the energy industry.

Table of Contents

As a result of recent declines in the quoted price of Dynegy s Class A common stock, its market capitalization is currently less than its stockholders equity. We have performed the test for impairment and concluded that a goodwill impairment loss has not occurred at this time. However, should Dynegy s stockholders equity remain above its market capitalization, further goodwill impairment testing will be performed in future periods and may result in an impairment loss, which could be material.

The LS Control Group s significant interest in Dynegy could be determinative in matters submitted to a vote by Dynegy s stockholders. In addition, the rights granted to the LS Shareholders (as defined below) under the Shareholder Agreement (as defined below) and Dynegy s amended and restated bylaws provide them significant influence over Dynegy. Such influence could result in Dynegy failing to take actions that Dynegy s other stockholders support.

The LS Control Group s ownership interest in Dynegy, together with its rights under the Shareholder Agreement and Dynegy s amended and restated bylaws, provides it with significant influence over the conduct of our business. Given the LS Control Group s significant interest in Dynegy, it may have the power to determine the outcome of matters submitted to a vote of all of Dynegy s stockholders.

Rights granted to the LS Control Group under the Shareholder Agreement and Dynegy s amended and restated bylaws that provide it with significant influence over Dynegy s business include:

- the ability to nominate up to three directors to Dynegy s board of directors based on its percentage ownership interest in Dynegy; and
- the requirement that Dynegy not pursue any of the following actions if all directors nominated by the LS Control Group present at the relevant board meeting vote against such action:
  - any amendment of Dynegy s amended and restated certificate of incorporation or amended and restated bylaws;
  - any merger or consolidation of Dynegy and certain dispositions of Dynegy s assets or businesses, certain acquisitions, binding capital commitments, guarantees and investments and certain joint ventures with an aggregate value in excess of a specified amount;
  - Dynegy s payment of dividends or similar distributions;
  - Dynegy s engagement in new lines of business;
  - Dynegy s liquidation or dissolution, or certain bankruptcy-related events with respect to Dynegy;
  - Dynegy s issuance of any equity securities, with certain exceptions for issuances of Dynegy s Class A common stock;
  - Dynegy s incurrence of any indebtedness in excess of a specified amount;
  - the hiring, or termination of the employment of, Dynegy s Chief Executive Officer (other than Bruce A. Williamson);
  - our entry into any agreement or other action that limits the activities of any holder of Dynegy s Class B common stock or any of such holder s affiliates; and
  - our entry into other material transactions with a value in excess of a specified amount.

The LS Control Group s influence could result in us failing to take actions that Dynegy s other stockholders do support.

Table of Contents

Dynegy s stockholders may be adversely affected by the expiration of the Lock-Up Period in the Shareholder Agreement, which would enable the LS Control Group to transfer a significant percentage of Dynegy s common stock to a third party.

The acquisition and transfer provisions in the Shareholder Agreement, subject to specified exceptions, restrict the LS Control Group from acquiring or transferring shares of Dynegy s common stock. Subject to specified exceptions, including the ability to transfer 21.25 million shares per six-month period (not to exceed 42.5 million shares in any one year), the LS Control Group is prohibited from acquiring or transferring shares of Dynegy s common stock until the expiration of the Lock-Up Period which is the earlier of:

- April 2, 2009;
- the date the stockholders party to the Shareholder Agreement cease to own at least 15 percent of the total combined voting power of Dynegy s outstanding securities; or
- if certain conditions are met, the date a third-party offer is made to acquire more than 25 percent of Dynegy s assets or voting securities.

Following expiration of the Lock-Up Period, the LS Control Group will be free to sell their shares of Dynegy s common stock, subject to certain exceptions, to any person on the open market, in privately negotiated transactions or otherwise in accordance with law. If the LS Control Group exercises this right, it could have a dilutive effect on the outstanding Class A common stock. In addition, the market s perception of how or when the LS Control Group might exercise its right could create an overhang on our Class A common stock and impact its trading price for an extended period of time.

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

We may seek to enter into transactions that may include acquiring or combining with other businesses. We may not be able to identify suitable acquisition or combination opportunities or finance and complete any particular acquisition or combination successfully. Furthermore, acquisitions and combinations involve a number of risks and challenges, including:

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

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize synergies or other anticipated benefits from a strategic transaction. Furthermore, the market for transactions is highly competitive, which may adversely affect our ability to find transactions that fit our strategic objectives or increase the price we would be required to pay (which could decrease the benefit of the transaction or hinder our desire or ability to consummate the transaction). Consistent with industry practice, we routinely engage in discussions with industry participants regarding potential transactions, large and small. We intend to continue to engage in strategic discussions and will need to respond to potential opportunities quickly and decisively. As a result, strategic transactions may occur at any time and may be significant in size relative to our assets and operations.

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 for further discussion, which is incorporated herein by reference. Substantially all of our assets, including the power generation facilities we own, are pledged as collateral to secure the repayment of, and our other obligations under, the Fifth Amended and Restated Credit Facility. Please read Note 15 Debt for further discussion.

Table of Contents

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

Item 3. ***Legal Proceedings***

Please read Note 19 Commitments and Contingencies Legal Proceedings for a description of our material legal proceedings, which is incorporated herein by reference.

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

Dynegy. No matter was submitted to a vote of Dynegy s security holders during the fourth quarter 2008.

DHI. Omitted pursuant to General Instruction (I)(2)(c) of Form 10-K.

Table of Contents

PART II

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

Dynegy

Dynegy s Class A common stock, $0.01 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 its Class A common stock as of February 20, 2009, based upon records of registered holders maintained by its transfer agent, was 19,966.

Dynegy s Class B common stock, $0.01 par value per share, is neither listed nor traded on any exchange. All of the shares of Class B common stock are owned by the LS Control Group (as defined below).

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, 2008 and 2007 and during the elapsed portion of Dynegy s first fiscal quarter of 2009 prior to the filing of this Form 10-K, as reported on the New York Stock Exchange Composite Tape.

Summary of Dynegy s Common Stock Price

	High	Low
2009:		
First Quarter (through February 20, 2009)	$ 2.69	$ 1.28
2008:		
Fourth Quarter	$ 4.06	$ 1.51
Third Quarter	8.76	3.20
Second Quarter	9.64	8.05
First Quarter	8.26	6.44
2007:		
Fourth Quarter	$ 9.50	$ 7.14
Third Quarter	10.62	7.86
Second Quarter	10.65	9.08
First Quarter	9.58	6.52

During the fiscal years ended December 31, 2008 and 2007, Dynegy s 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 Dynegy Common Stock for further discussion of its dividend policy and the impact of dividend restrictions contained in its financing agreements. Any decision to pay a dividend will be at the discretion of Dynegy s Board of Directors, and subject to the terms of its then-outstanding indebtedness, but Dynegy does not expect to pay a dividend on any class of its common stock in the foreseeable future. Dynegy has not paid a dividend on any class of its common stock since 2002. Please read Note 20 Capital Stock Common Stock for further discussion.

Shareholder Agreement. Dynegy entered into a Shareholder Agreement dated as of September 14, 2006 (the Shareholder Agreement) with LSP Gen Investors, L.P., LS Power Partners, L.P., LS Power Equity Partners PIE I, L.P., LS Power Equity Partners, L.P. and LS Power Associates, L.P. (LS Associates and, collectively, the LS Entities) that, among other things, limits the LS Entities ownership of Dynegy s common stock, subject to specified exceptions, and restricts the manner in which the LS Entities may transfer their shares of Class B common stock. The LS Entities and their permitted transferees, affiliates and associates (the LS Control Group), together with Luminus Management LLC and its affiliates (Luminus), may not acquire any of Dynegy s equity securities if, after giving effect to such acquisition, they would own more than approximately 40 percent of the total outstanding shares of Dynegy s common stock (approximately 41 percent including Luminus).

30

In addition, after the expiration of the earlier of (i) two years from the closing of the merger between us and the LS Entities on April 2, 2007 (the Merger), (ii) the date the LS Entities cease to collectively own 15 percent of Dynegy s outstanding voting securities and (iii) the occurrence of certain third-party offers to acquire more than 25 percent of Dynegy (the Lock-Up Period), the LS Entities may make a Qualified Offer, as defined in the Shareholder Agreement, to purchase all of the outstanding shares of Dynegy s common stock. Upon such offer, which generally must be for cash and accompanied by a fairness opinion, Dynegy may either accept the offer or, if it rejects such offer and the LS Entities so elect, conduct an auction in which the LS Entities may elect, at their option, whether or not to participate. The LS Entities have the right to top any offer selected by Dynegy s Board of Directors at 105 percent of the offer price in any auction in which they elect not to participate. In the case of an unsuccessful auction within the contractually prescribed time period, the LS Entities may continue with their Qualified Offer, which may take the form of a tender offer to Dynegy s Class A common stockholders. Any such tender offer would require approval by holders of at least a majority of Dynegy s Class A common stock.

The Shareholder Agreement also (i) provides that if the LS Entities or the Class B common stock directors block certain sale transactions with respect to Dynegy more than twice in any 18 month period, Dynegy s Board can cause an auction for the sale of Dynegy, (ii) prohibits Dynegy from issuing Class B common stock to any person other than the LS Entities and (iii) provides the LS Entities with certain preemptive rights to acquire shares of Dynegy s common stock in proportion to their then-existing ownership of our common stock whenever we issue shares of stock or securities convertible into Dynegy s common stock.

Generally, until the expiration of the Lock-Up Period, the LS Control Group may not transfer their shares, provided that, (i) beginning September 29, 2007 (that is, 180 days after the Merger), the LS Control Group may distribute their shares to their permitted transferees; provided that Dynegy may block such distribution for up to 60 days per calendar year in connection with a proposed underwritten public offering; (ii) during the period that began on September 29, 2007 and ended on March 26, 2008, 21,250,000 shares of Class B common stock may be transferred in widely dispersed sales, provided that to the extent such number of shares is not transferred during any such 180-day period, any unused amount may be carried forward to the next succeeding 180-day period (but in no event may more than 42,500,000 share of Class B common stock be transferred during any 180-day period); and (iii) after expiration of the Lock-Up Period, the LS Control Group may freely transfer their shares of Class B common stock to any person so long as such transfer would not result in such person, together with such person s affiliates and associates, owning more than 15 percent of shares of Dynegy s common stock. Any transfers during this post-Lock-Up Period that are not part of a widely dispersed sale will be considered block sales and will result in a ratchet down of the standstill cap on a share-per-share basis. All shares of Class B common stock transferred to any person that is not a member of the LS Control Group will automatically be converted into shares of Class A common stock.

LS Registration Rights Agreement. In connection with the Merger, Dynegy entered into a Registration Rights Agreement dated September 14, 2006 (LS Registration Rights Agreement) with the LS Entities pursuant to which Dynegy agreed to prepare and file with the SEC a shelf registration statement covering the resale of shares of Class A common stock issuable upon the conversion of (i) shares of Class B common stock that were issued to the LS Entities in the Merger and (ii) any shares of Class B common stock that may be transferred by the LS Entities to their permitted transferees. Dynegy filed this shelf registration statement with the SEC on April 5, 2007.

Under the LS Registration Rights Agreement, the LS Entities and their permitted transferees have the right to cause Dynegy to effect up to two underwritten offerings during the first 24 months following the Merger, provided that no more than one underwritten offering may be consummated during each of the first and second 12-month periods. The LS Entities and their permitted transferees may demand to effect up to two underwritten offerings during each 12-month period following the first 24 months after the Merger. We may defer the commencement of any underwritten offering demanded by the LS Entities and their permitted transferees for up to 60 days one time in any calendar year.

Table of Contents

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

1. $100 was invested in Dynegy Class A common stock, the S&P 500, the Peer Group (as defined below) on December 31, 2003;
2. the returns of each component company in the Peer Group are weighed based on the market capitalization of such company at the beginning of the measurement period; and
3. dividends are reinvested on the ex-dividend dates.

Our peer group for the fiscal years ended December 31, 2008 and 2007 is comprised of Mirant Corporation, NRG Energy, Inc., and Reliant Energy, Inc. We typically include Calpine Corporation as one of our peer companies as they are considered an independent power producer. However, they are not included in the data below, as they emerged from bankruptcy protection in January 2008. As a result, there is insufficient comparable historical data.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Dynegy Inc. The S&P 500 Index

And A Peer Group

* $100 invested on 12/31/03 in stock & index-including reinvestment of dividends. Fiscal year ending December 31.

	12/03	**12/04**	**12/05**	**12/06**	**12/07**	**12/08**
Dynegy Inc.	100.00	107.94	113.08	169.16	166.82	46.73
S&P 500	100.00	110.88	116.33	134.70	142.10	89.53
Peer Group	100.00	174.98	177.55	241.73	359.04	151.50

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

Table of Contents

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

Unregistered Sales of Equity Securities and Use of Proceeds. When restricted stock awarded by Dynegy becomes taxable compensation to employees, shares may be withheld to cover the employees withholding taxes. Information on Dynegy s purchases of equity securities by means of such share withholdings during the quarter follows:

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October				N/A
November	269	$ 3.64		N/A
December	6,189	$ 2.18		N/A
Total	6,458	$ 2.24		N/A

These were the only repurchases of equity securities made by Dynegy during the three months ended December 31, 2008. Dynegy does not have a stock repurchase program.

DHI

All of DHI s outstanding equity securities are held by its parent, Dynegy. There is no established trading market for such securities and they are not traded on any exchange.

Securities Authorized for Issuance Under Equity Compensation Plans

Please read Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters Dynegy for information regarding securities authorized for issuance under our equity compensation plans.

Table of Contents

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

Dynegy s Selected Financial Data

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$ 3,549	$ 3,103	$ 1,770	$ 2,017	$ 2,249
Depreciation and amortization expense	(371)	(325)	(217)	(208)	(221)
Impairment and other charges	(47)		(119)	(46)	(78)
General and administrative expenses	(157)	(203)	(196)	(468)	(330)
Operating income (loss)	709	605	105	(832)	(66)
Interest expense and debt conversion expense	(427)	(384)	(631)	(389)	(453)
Income tax (expense) benefit	(75)	(151)	152	393	158
Income (loss) from continuing operations	171	116	(321)	(800)	(160)
Income (loss) from discontinued operations (3)	3	148	(13)	895	145
Cumulative effect of change in accounting principles			1	(5)	
Net income (loss)	$ 174	$ 264	$ (333)	$ 90	$ (15)
Net income (loss) applicable to common stockholders	174	264	(342)	68	(37)
Basic earnings (loss) per share from continuing operations	$ 0.20	$ 0.15	$ (0.72)	$ (2.12)	$ (0.48)
Basic net income (loss) per share	0.20	0.35	(0.75)	0.18	(0.10)
Diluted earnings (loss) per share from continuing operations	$ 0.20	$ 0.15	$ (0.72)	$ (2.12)	$ (0.48)
Diluted net income (loss) per share	0.20	0.35	(0.75)	0.18	(0.10)
Shares outstanding for basic EPS calculation	840	752	459	387	378
Shares outstanding for diluted EPS calculation	842	754	509	513	504
Cash dividends per common share	$	$	$	$	$
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ 319	$ 341	$ (194)	$ (30)	$ 5
Net cash provided by (used in) investing activities	(102)	(817)	358	1,824	262
Net cash provided by (used in) financing activities	148	433	(1,342)	(873)	(115)

Cash dividends or distributions to partners, net			(17)	(22)	(22)
Capital expenditures, acquisitions and investments	(640)	(504)	(163)	(315)	(314)

	2008	2007	December 31, 2006 (in millions)	2005	2004
Balance Sheet Data (2):					
Current assets	$ 2,803	$ 1,663	$ 1,989	$ 3,706	$ 2,728
Current liabilities	1,702	999	1,166	2,116	1,802
Property and equipment, net	8,934	9,017	4,951	5,323	6,130
Total assets	14,213	13,221	7,537	10,126	9,843
Long-term debt (excluding current portion)	6,072	5,939	3,190	4,228	4,332
Notes payable and current portion of long-term debt	64	51	68	71	34
Series C convertible preferred stock				400	400
Minority interest	(30)	23			106
Capital leases not already included in long-term debt	4	5	6		
Total equity	4,515	4,506	2,267	2,140	1,956

(1) The Merger (April 2, 2007) and the Sithe Energies acquisition (February 1, 2005) were each accounted for in accordance with the purchase method of accounting and the results of operations attributable to the acquired businesses are included in our financial statements and operating statistics beginning on the acquisitions effective date for accounting

purposes.

(2) The Merger and the Sithe Energies acquisition 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. Please read note (1) above for respective effective dates.

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

DMSLP (sold fourth quarter 2005);

Calcasieu power generating facility (sold first quarter 2008); and

CoGen Lyondell power generating facility (sold third quarter 2007).

Dynegy Holdings Selected Financial Data

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$ 3,549	$ 3,103	$ 1,770	$ 2,017	$ 1,447
	(371)	(325)	(217)	(208)	(210)

Depreciation and amortization expense					
Impairment and other charges	(47)		(119)	(40)	(24)
General and administrative expenses	(157)	(184)	(193)	(375)	(285)
Operating income (loss)	709	624	108	(733)	(202)
Interest expense and debt conversion expense	(427)	(384)	(579)	(383)	(332)
Income tax (expense) benefit	(123)	(116)	125	374	166
Income (loss) from continuing operations	205	176	(296)	(727)	(247)
Income (loss) from discontinued operations (2)	3	148	(12)	813	143
Cumulative effect of change in accounting principles				(5)	
Net income (loss)	$ 208	$ 324	$ (308)	$ 81	$ (104)
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ 319	$ 368	$ (205)	$ (24)	$ (160)
Net cash provided by (used in) investing activities	(87)	(688)	357	1,839	(211)
Net cash provided by (used in) financing activities	146	369	(1,235)	(734)	289
Capital expenditures, acquisitions and investments	(626)	(350)	(155)	(169)	(219)

	2008	2007	December 31, 2006 (in millions)	2005	2004
Balance Sheet Data (1):					
Current assets	$ 2,780	$ 1,614	$ 1,828	$ 3,457	$ 2,192
Current liabilities	1,681	999	1,165	2,212	1,773
Property and equipment, net	8,934	9,017	4,951	5,323	6,130
Total assets	14,174	13,107	8,136	10,580	10,129
Long-term debt (excluding current portion)	6,072	5,939	3,190	4,003	4,107
Notes payable and current portion of long-term debt	64	51	68	191	34
Minority interest	(30)	23			106
Capital leases not already included in long-term debt	4	5	6		
Total equity	4,613	4,597	3,036	3,331	3,085

(1) The Contributed Entities assets were contributed to DHI contemporaneously with the Merger. This contribution was accounted for

as a transaction between entities under common control. As such, the assets and liabilities were recorded by DHI at Dynegy s historical cost on Dynegy s date of acquisition. Please read Note 3 Business Combination and Acquisitions LS Assets Contribution for further discussion. Additionally, the Sithe Energies assets were contributed to DHI on April 2, 2007. This contribution was accounted for as a transaction between entities under common control. As such, the assets and liabilities were recorded by DHI at Dynegy s historical cost on Dynegy s date of acquisition, January 31, 2005. In addition, DHI s historical financial statements have been adjusted in all periods presented to reflect the contribution as though DHI had owned these assets beginning January 31, 2005. Please read Note 3 Business Combination and Acquisitions LS Assets Contribution

for further
discussion.

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

- DMSLP (sold fourth quarter 2005);
- Calcasieu power generating facility (sold first quarter 2008); and
- CoGen Lyondell power generating facility (sold third quarter 2007).

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 holding companies 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: (i) GEN-MW; (ii) GEN-WE; and (iii) GEN-NE. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. Beginning in the first quarter 2008, the results of our former customer risk management business are included in Other as it does not meet the criteria required to be an operating segment as of January 1, 2008. Accordingly, we have restated the corresponding items of segment information for prior periods. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization. Dynegy s 50 percent investment in DLS Power Development, the dissolution of which will be completed in the first quarter of 2009, is included in Other for segment reporting purposes.

In addition to our operating generation facilities, we own an approximate 37 percent interest in PPEA which, through its wholly owned subsidiary, owns an approximate 57 percent undivided interest in Plum Point, a 665 MW coal-fired power generation facility under construction in Mississippi County, Arkansas, which is included in GEN-MW. We also own a 50 percent interest in SCH, which owns an approximate 64 percent undivided interest in Sandy Creek, an 898 MW power generation facility under construction in McLennan County, Texas, which is included in GEN-WE.

The following is a brief discussion of each of our power generation segments, including a list of key factors that have affected, and are expected to continue to affect, their respective earnings and cash flows. We also present a brief discussion of our corporate-level expenses. This Overview section concludes with a discussion of our 2008 company highlights. Please note that this Overview section is merely a summary and should be read together with the remainder of this Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, as well as our audited consolidated financial statements, including the notes thereto, and the other information included in this report.

Business Discussion

Power Generation Business

We generate earnings and cash flows in the three segments within our power generation business through sales of electric energy, capacity and ancillary services. Primary factors affecting our earnings and cash flows in the power generation business include:

- Prices for power, natural gas, coal and fuel oil, which in turn are largely driven by supply and demand. Demand for power can vary due to weather and general economic conditions, among other things. For example, a warm summer or a cold winter typically increases demand for electricity. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation;

The relationship between prices for power and natural gas and prices for power and fuel oil, commonly referred to as the spark spread , which impacts the margin we earn on the electricity we generate. We believe that our coal-fired generating facilities provide a certain level of predictability of earnings in the near term since our delivered cost of coal, particularly in the Midwest region, is relatively stable and positions us for potential increases in earnings and cash flows in an environment where power prices increase; and

Our ability to enter into commercial transactions to mitigate near term earnings volatility and our ability to better manage our liquidity requirements resulting from potential changes in collateral requirements as prices move.

Table of Contents

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

- Transmission constraints, congestion, and other factors that can affect the price differential between the locations where we deliver generated power and the liquid market hub;
- Our ability to control capital expenditures, which primarily include maintenance, safety, environmental and reliability projects, and to control other costs through disciplined management;
- Overall electricity demand patterns;
- Our ability to optimize our assets by maintaining a high in-market availability, reliable run-time and safe, efficient operations; and
- The cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive.

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

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

Power Generation Midwest Segment. Our assets in the Midwest segment include a coal-fired fleet and a natural gas-fired fleet. The following specific factors affect or could affect the performance of this reportable segment:

- Our ability to maintain sufficient coal inventories, which is dependent upon the continued performance of the railroads for deliveries of coal in a consistent and timely manner, and its impact on our ability to serve the critical winter and summer on-peak loads;
- Our requirement for the next four years to utilize a significant amount of cash for capital expenditures required to comply with the Consent Decree;
- Changes in the MISO market design or associated rules; and
- Changes in the existing PJM RPM capacity markets or in the bilateral MISO capacity markets and any resulting effect on future capacity revenues.

Power Generation West Segment. Our assets in the West segment are all natural gas-fired power generating facilities with the exception of our fuel oil-fired Oakland power generating facility. The following specific factors impact or could impact the performance of this reportable segment:

- Our ability to maintain the necessary permits to continue to operate our Moss Landing power generation facility with a once-through, seawater cooling system;
- Our ability to maintain and operate our plants in a manner that ensures we receive full capacity payments under our various tolling agreements; and
- The economic life of our facilities, which could be adversely impacted by contractual obligations, regulatory actions or other factors.

Table of Contents

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

- Our ability to maintain sufficient coal and fuel oil inventories, including continued deliveries of coal in a consistent and timely manner, and maintain access to natural gas, impacts our ability to serve the critical winter and summer on-peak loads; and
- State-driven programs aimed at capping mercury and CO_2 emissions will impose additional costs on our power generation facilities.

Other

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

- Interest expense, which reflects debt with a weighted-average rate of approximately 7 percent;
- General and administrative costs, which will be impacted by, among other things, (i) staffing levels and associated expenses; (ii) funding requirements under our pension plans; and (iii) any future corporate-level litigation reserves or settlements; and
- Income taxes, which will be impacted by our ability to realize our significant alternative minimum tax credits.

Other also includes our former CRM segment, which primarily consists of a minimal number of legacy power and natural gas trading positions that will remain until 2010 and 2017, respectively.

2008 Highlights

DLS Power Holdings and DLS Power Development Dissolution. Effective January 1, 2009, Dynegy entered into an agreement with LS Associates to dissolve DLS Power Holdings and DLS Power Development, our development joint ventures with LS Power Associates. Under the terms of this agreement, we acquired exclusive rights related to repowering and expansion opportunities at our existing facilities. In return, LS Power Associates received a cash payment of approximately $19 million, as well as full rights to new greenfield development opportunities previously held by the joint venture. As a result of this agreement, we recorded a $71 million pre-tax charge related to our investment in the joint ventures, which consisted of a $24 million impairment and a $47 million loss on dissolution. This dissolution has no effect on our ownership rights in the Plum Point or Sandy Creek projects. Please read Note 12 Variable Interest Entities DLS Power Holdings and DLS Power Development for further discussion.

Rolling Hills. On July 31, 2008, we completed the sale of the Rolling Hills power generation facility to an affiliate of Tenaska Capital Management, LLC for approximately $368 million, net of transaction costs. We recorded a gain of approximately $56 million related to the sale of the facility in the third quarter 2008. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Rolling Hills for further discussion.

Contingent LC Facility. On June 17, 2008, DHI entered into the Contingent LC Facility with Morgan Stanley. Availability under the Contingent LC Facility is contingent on natural gas prices rising above $13/MMBtu during 2009. In the event that the Contingent LC Facility is utilized, it will complement existing liquidity instruments as a source of additional letters of credit to meet our collateral requirements. Such letters of credit will be available for the purpose of supporting certain commercial and trading contracts and related netting agreements described in the Credit Agreement. Please read Note 15 Debt Contingent LC Facility for further discussion.

Table of Contents

Sandy Creek. On June 6, 2008, SCEA sold an 11 percent undivided interest in the Sandy Creek Project to an unaffiliated third party, reducing its undivided interest in the project from approximately 75 percent to approximately 64 percent. Losses from unconsolidated investments include a net gain of approximately $13 million related to the sale. Using cash on hand and the proceeds of the sale, SCEA repaid approximately $45 million in project related debt and approximately $7 million in affiliate debt. In addition, we received a distribution of approximately $7 million during the second quarter 2008. Please read Note 12 Variable Interest Entities Sandy Creek for further discussion.

LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. 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 (including required environmental expenditures), potential funding commitments for our equity investment and working capital needs. Examples of working capital needs include purchases of commodities, particularly natural gas and coal, facility maintenance costs and other costs such as payroll.

Our primary sources of internal liquidity are cash flows from operations, cash on hand, available capacity under our Credit Agreement, of which the revolver capacity of $1,080 million is scheduled to mature in April 2012 and the term letter of credit capacity of $850 million is scheduled to mature in April 2013, and available capacity under our Contingent LC Facility, as described further below. Our primary sources of external liquidity are asset sales proceeds and proceeds from capital market transactions to the extent we engage in these transactions. Operating cash flows provided by our power generation assets and the available cash we currently hold are expected to be sufficient to fund the operation of our business, as well as our planned capital expenditure program, including expenditures in connection with the Consent Decree, and debt service requirements over the next twelve months. We maintain capacity under the Credit Agreement in order to post collateral in the form of letters of credit or cash, and we believe we have sufficient capacity should we be required to post additional collateral. Please read Note 15 Debt Fifth Amended and Restated Credit Facility for a discussion of the financial covenants contained in the Credit Agreement, as well as the discussion below regarding our Revolver Capacity. Additionally, DHI may borrow money from time to time from Dynegy.

Market Conditions

The latter half of 2008 was characterized by turmoil in the financial markets that many have referred to as a liquidity crisis. Several large financial institutions have failed, and stock prices across industries, including Dynegy s, have fallen sharply. These market conditions have resulted in a decreased willingness on the part of lenders to enter into new loans. Although recent market developments have not had a material adverse impact on our ability to conduct our business, they have affected us directly in several ways:

- Lehman Commercial Paper Inc. (Lehman CP), a lender under our Credit Agreement, entered bankruptcy proceedings. As a result, our effective availability under the Credit Agreement may be reduced by $70 million to $1.9 billion;
- We recorded a reserve of $3 million as a result of the bankruptcy of LBH. This reserve represents the uncollateralized portion of our $15 million net position arising from our outstanding commercial transactions with a subsidiary of LBH;
- A large money market fund in which we invested a portion of our cash balance lowered its share price below $1, subsequently suspended distributions and commenced liquidation. As a result, we reclassified our $127 million investment from cash equivalents to short-term investments and recorded a $2 million impairment. We have received approximately $100 million of distributions as of December 31, 2008; and
- A decrease in liquidity in the bilateral markets for forward power sales, resulting in increased exchange-traded transactions settling through our futures clearing manager that can potentially result in the need for additional cash collateral postings.

The banks and other counterparties with which we transact have also been affected by market developments in various ways, which could affect their ability to enter into transactions with us and further impact the way we conduct our business.

Also, as a result of the recent decline in the overall capital markets, the value of our pension plan assets has decreased as of December 31, 2008. Please read Note 21 Employee Compensation, Savings and Pension Plan Pension and Other Post-Retirement Benefits for further discussion.

Corporate Matters

On September 14, 2006, Dynegy entered into the Shareholder Agreement with the LS Entities that, among other things, limits the LS Entities ownership of Dynegy s common stock and restricts the manner in which the LS Entities may transfer their shares of Class B common stock. Specifically, subsequent to April 2, 2009, the LS Entities may:

- continue to hold their 40 percent investment in Dynegy;
- make an offer to purchase all of the outstanding shares of Dynegy s common stock. Upon such offer, we may either (i) accept the offer or (ii) if requested by the LS Entities, conduct an auction of Dynegy in which the LS Entities may elect whether or not to participate; or
- freely transfer (i.e. sell) their shares of Dynegy s Class B common stock to any person so long as such transfer would not result in such person owning more than 15 percent of the outstanding shares of Dynegy s common stock.

Current Liquidity. The following table summarizes our consolidated revolver capacity and liquidity position at February 20, 2009, December 31, 2008 and December 31, 2007:

	February 20, 2009	December 31, 2008	December 31, 2007
		(in millions)	
Revolver capacity (1) (2) (3)	$ 1,080	$ 1,080	$ 1,150
Borrowings against revolver capacity			
Term letter of credit capacity, net of required reserves	825	825	825
Plum Point and Sandy Creek letter of credit capacity	377	377	425
Available contingent letter of credit facility capacity (4)			
Outstanding letters of credit	(1,104)	(1,135)	(1,279)
Unused capacity	1,178	1,147	1,121
Cash DHI	675	670	292
Total available liquidity DHI	1,853	1,817	1,413
Cash Dynegy	183	23	36
Total available liquidity Dynegy	$ 2,036	$ 1,840	$ 1,449

(1) Lehman CP filed for protection from creditors under the bankruptcy law in October 2008, thus potentially reducing the

available capacity of the revolving portion of the Credit Agreement by $70 million. Please read Note 15 Debt Credit Agreement for further discussion. We continue to believe that we maintain sufficient liquidity despite any such reduction in the available capacity under the revolving portion of our Credit Agreement.

(2) We currently have 15 lenders participating in the revolving portion of our Credit Agreement with commitments ranging from $10 million to $105 million. Other than the commitment from Lehman CP, we have not experienced, nor do we currently anticipate, any difficulties in obtaining funding from any of the remaining lenders at this

time. However, we continue to monitor the environment, and any lack of or delay in funding by a significant member or multiple members of our banking group could negatively affect our liquidity position.

(3) Based on management s current forecast of financial performance during 2009, DHI s available liquidity under the Fifth Amended and Restated Credit Facility may be reduced temporarily in order to remain in compliance with the secured debt to adjusted EBITDA ratio.

(4) Under the terms of the Contingent LC Facility, up to $300 million of capacity can become available, contingent on 2009 forward natural gas prices rising above $13/MMBtu.

Over the course of 2009, the ratio of availability per dollar increase in natural gas prices will be reduced, on a pro rata monthly basis, to zero by year-end.

Table of Contents

Cash on Hand. At February 20, 2009 and December 31, 2008, Dynegy had cash on hand of $858 million and $693 million, respectively, as compared to $328 million at the end of 2007. The increase in cash on hand at February 20, 2009 compared with December 31, 2008 is the result of cash provided by the operating activities of our generating business. The change in cash on hand at December 31, 2008 as compared to the end of 2007 is primarily attributable to cash provided by the operating activities of our generating business, proceeds received from the sale of our Rolling Hills and Calcasieu power generation facilities and reduced capital commitments in connection with the Sandy Creek Project due to the sale of an approximate 11 percent ownership interest, partly offset by capital expenditures and payments on our DNE Leveraged lease.

At February 20, 2009 and December 31, 2008, DHI had cash on hand of $675 million and $670 million, respectively, as compared to $292 million at the end of 2007. Cash provided by the operating activities of our generating business for the period from December 31, 2008 to February 20, 2009 was offset by the payment of a $175 million dividend from DHI to Dynegy in January, 2009. The increase in cash on hand at December 31, 2008 as compared to the end of 2007 is primarily attributable to cash provided by the operating activities of our generating business and proceeds received from the sale of our Rolling Hills and Calcasieu power generation facilities and reduced capital commitments in connection with the Sandy Creek Project due to the sale of an approximate 11 percent ownership interest, partly offset by capital expenditures, dividends paid to Dynegy and payments on our DNE Leveraged lease.

Revolver Capacity. On April 2, 2007, DHI entered into the Fifth Amended and Restated Credit Facility, which is our primary credit facility. On May 24, 2007, DHI entered into an amendment to the Fifth Amended and Restated Credit Facility. As of February 20, 2009, $1,104 million in letters of credit are outstanding but undrawn, and we have no revolving loan amounts drawn under the Fifth Amended and Restated Credit Facility. The Fifth Amended and Restated Credit Facility has financial covenants which could restrict our ability to realize full capacity utilization based on levels of realized EBITDA, all as defined in Section 7.11 of the Fifth Amended and Restated Credit Facility. Based on management s current forecast of financial performance during 2009, DHI s available liquidity under the Fifth Amended and Restated Credit Facility may be reduced temporarily in order to remain in compliance with the secured debt to adjusted EBITDA ratio. Please read Note 15 Debt Fifth Amended and Restated Credit Facility for further discussion of our amended credit facility.

Operating Activities

Historical Operating Cash Flows. Dynegy s cash flow provided by operations totaled $319 million for the twelve months ended December 31, 2008. DHI s cash flow provided by operations totaled $319 million for the twelve months ended December 31, 2008. During the period, our power generation business provided positive cash flow from operations of $869 million from the operation of our power generation facilities, reflecting positive earnings for the period, partly offset by additional collateral requirements due to an increase in the volume of our hedging positions and increased payments associated with our DNE leveraged lease. Corporate and other operations included a use of approximately $550 million in cash by Dynegy and DHI primarily due to interest payments to service debt, general and administrative expenses and a $17 million legal settlement payment previously reserved, partially offset by interest income.

Dynegy s cash flow provided by operations totaled $341 million for the twelve months ended December 31, 2007. DHI s cash flow provided by operations totaled $368 million for the twelve months ended December 31, 2007. During the period, our power generation business provided positive cash flow from operations of $934 million primarily due to positive earnings for the period, partly offset by an increased use of working capital. Corporate and other operations included a use of approximately $593 million in cash by Dynegy and approximately $566 million in cash by DHI relating to corporate-level expenses and our former customer risk management business.

Dynegy s cash flow used in operations totaled $194 million for the twelve months ended December 31, 2006. DHI s cash flow used in operations totaled $205 million for the twelve months ended December 31, 2006. During the period, our power generation business provided positive cash flow from operations of $698 million primarily due to positive earnings for the period, decreases in working capital due to returns of cash collateral postings and decreased accounts receivable balances. Corporate and other operations included a use of approximately $892 million in cash by Dynegy and approximately $903 million in cash by DHI relating to corporate-level expenses and our former customer risk management business.

Table of Contents

Future Operating Cash Flows. Our future operating cash flows will vary based on a number of factors, many of which are beyond our control, including the price of natural gas and its correlation to power prices, the cost of coal and fuel oil, the value of capacity and ancillary services and legal and regulatory requirements. Additionally, the availability of our plants during peak demand periods will be required to allow us to capture attractive market prices when available. Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to tightly manage our operating costs, including maintenance costs, in balance with ensuring that our plants are available to operate when markets offer attractive returns.

Collateral Postings. 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 counterparties views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The following table summarizes our consolidated collateral postings to third parties by line of business at February 20, 2009, December 31, 2008 and December 31, 2007:

	February 20, 2009	December 31, 2008 (in millions)	December 31, 2007
By Business:			
Generation business	$ 1,128	$ 1,064	$ 1,130
Other	189	189	202
Total	$ 1,317	$ 1,253	$ 1,332
By Type:			
Cash (1)	$ 213	$ 118	$ 53
Letters of credit	1,104	1,135	1,279
Total	$ 1,317	$ 1,253	$ 1,332

(1) Cash collateral postings exclude the effect of cash inflows and outflows arising from the daily settlements of our exchange-traded or brokered commodity futures positions held with our futures clearing manager.

The changes in collateral postings are primarily due to the volume of forward power sales and fuel purchase transactions and the effect of changing commodity prices on such transactions. Letters of credit posted under the letter of credit portion of our Credit Agreement and the stand-alone letter of credit facility posted in support of our Sandy Creek facility are supported with restricted cash.

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. We believe that we have sufficient capital resources to satisfy counterparties collateral demands, including those for which no collateral is currently posted, for the foreseeable future.

We have structured our liquidity facilities to provide us with the flexibility to enable us to post additional collateral to support our financial positions as needed in the event that natural gas and power prices increase. For example, at June 30, 2008, the average natural gas prices for the remainder of 2008 and for 2009 were $13.54/MMBtu and $12.47/MMBtu, respectively. Even in this environment of high prices, we maintained $890 million of available liquidity.

Table of Contents

Investing Activities

Capital Expenditures. We continue to tightly manage our operating costs and capital expenditures. We had approximately $611 million, $379 million and $155 million in capital expenditures during 2008, 2007 and 2006. Our capital spending by reportable segment was as follows:

	December 31, 2008	December 31, 2007	December 31, 2006
	(in millions)		
GEN-MW	$ 530	$ 300	$ 101
GEN-WE	29	17	24
GEN-NE	36	47	22
Other	16	15	8
Total	$ 611	$ 379	$ 155

Capital spending in our GEN-MW segment primarily consisted of environmental and maintenance capital projects, as well as approximately $203 million and $161 million spent on development capital related to the Plum Point Project during the years ended December 31, 2008 and 2007, respectively. Capital spending in our GEN-WE and GEN-NE segments primarily consisted of maintenance projects.

We expect capital expenditures for 2009 to approximate $490 million, which is comprised of $431 million, $16 million, $28 million and $15 million in GEN-MW, GEN-WE, GEN-NE and other, respectively. The $431 million of spending planned for GEN-MW includes $80 million related to construction of the Plum Point facility and approximately $245 million of environmental expenditures related to the Consent Decree. The capital expenditures related to Plum Point will be funded by non-recourse project debt. Please read Note 15 Debt Plum Point Credit Agreement Facility for further discussion. Other spending primarily includes maintenance capital projects, environmental projects and limited development projects. The capital budget is subject to revision as opportunities arise or circumstances change.

The Consent Decree was finalized in July 2005. It prohibits us from operating certain of our power generating facilities after specified dates unless certain emission control equipment is installed. Our long-term capital expenditures in the GEN-MW segment will be significantly impacted by this Consent Decree. We anticipate our costs associated with the Consent Decree projects, which we expect to incur through 2012, to be approximately $960 million, which includes approximately $290 million spent to date. This estimate, which is broken down by year below, includes a number of assumptions about uncertainties that are beyond our control. For instance, we have assumed for purposes of this estimate that labor and material costs will increase at four percent per year over the remaining project term. The following are the estimated capital expenditures required to comply with the Consent Decree:

2009	2010	2011	2012
	(in millions)		
$ 245	$ 215	$ 165	$ 45

If the costs of these capital expenditures become great enough to render the operation of the affected facility or facilities uneconomical, we could, at our option, cease to operate the facility or facilities and forego these capital expenditures without incurring any further obligations under the Consent Decree. Please read Note 19 Commitments and Contingencies Other Commitments and Contingencies Midwest Consent Decree for further discussion.

Finally, the SPDES permits renewal application at our Roseton power generating facility and the NPDES permit at our Moss Landing power generating facility have been challenged by local environmental groups which contend the existing once-through, seawater cooling systems currently in place should be replaced with closed-cycle cooling systems. A decision to install a closed cycle cooling system at the Roseton or Moss Landing facilities would be made on a case-by-case basis considering all relevant factors at such time, including any relevant costs or applicable remediation requirements. If mandated installation of closed cycle cooling systems at either of these facilities would result in a material capital expenditure that renders the operation of a plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such facility and forego these capital expenditures.

Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Disclosure of Contractual Obligations and Contingent Financial Commitments Off-Balance Sheet Arrangements DNE Leveraged Lease for further discussion of early lease termination payments. Please read Note 19 Commitments and Contingencies Legal Proceedings Roseton State Pollutant Discharge Elimination System Permit and Commitments and Contingencies Legal Proceedings Moss Landing National Pollutant Discharge Elimination System Permit for further discussion.

Asset Dispositions. Proceeds from asset sales in 2008 totaled $451 million, net of transaction costs, related to the sales of the Rolling Hills power generating facility, Calcasieu power generating facility, the NYMEX shares and seats, and the beneficial interest in Oyster Creek. Proceeds from asset sales in 2007 totaled $558 million and primarily consisted of $472 million from the sale of our CoGen Lyondell power generation facility and $82 million received in connection with the sale of a portion of our interest in the Plum Point Project. Proceeds from asset sales in 2006 totaled $227 million, net, and primarily related to the sale of our Rockingham facility for $194 million. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations for further discussion.

On February 25, 2009, we entered into an agreement to sell our interest in the Heard County power generation facility to Oglethorpe. Subject to regulatory approval, the transaction is expected to close in the first half of 2009. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Heard County for further discussion.

Consistent with industry practice, we regularly evaluate our generation fleet based primarily on geographic location, fuel supply, market structure and market recovery expectations. We consider divestitures of non-core generation assets where the balance of the above factors suggests that such assets earnings potential is limited or that the value that can be captured through a divestiture outweighs the benefits of continuing to own and operate such assets. Additional dispositions of one or more generation facilities or other investments could occur in 2009 or beyond. Were any such sale or disposition to be consummated, the disposition could result in accounting charges related to the affected asset(s), and our future earnings and cash flows could be affected.

Other Investing Activities. Dynegy made $16 million and $10 million in contributions to DLS Power Holdings during the years ended December 31, 2008 and 2007, respectively. We received a distribution of approximately $7 million and repayment of approximately $3 million of an affiliate receivable upon the sale of a partial interest in Sandy Creek during the year ended December 31, 2008. We received a distribution of approximately $13 million upon the sale of a partial interest in Sandy Creek during the year ended December 31, 2007. Please read Note 12 Variable Interest Entities Sandy Creek for further discussion.

Cash outflows related to short-term investments during the year ended December 31, 2008 increased by $27 million and $25 million for Dynegy and DHI, respectively, as a result of a reclassification from cash equivalents to short-term investments. There was a $128 million, net of cash acquired, cash outflow during the year ended December 31, 2007 used in connection with the completion of the Merger. Please read Note 3 Business Combinations and Acquisitions LS Power Business Combination for more information.

Proceeds from the exchange of unconsolidated investments, net of cash acquired, totaled $165 million during the year ended December 31, 2006. This included net cash proceeds of $205 million from the sale of our 50 percent ownership interest in West Coast Power to NRG. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations West Coast Power for further information. This was partially offset by a payment of $45 million for our acquisition of NRG s 50 percent ownership interest in Rocky Road, which included $5 million of cash on hand. Please read Note 3 Business Combinations and Acquisitions Rocky Road for more information.

There was an $80 million cash inflow during the year ended December 31, 2008 due to changes in restricted cash balances primarily due to a reduction of our cash collateral as a result of SCEA s sale of an 11 percent undivided interest in the Sandy Creek Project, the release of restricted cash and the use of restricted cash for the ongoing construction of the Plum Point Project, partially offset by interest income. The increase in restricted cash and investments of $871 million during the twelve months ended December 31, 2007 related primarily to a $650 million deposit associated with our cash collateralized facility, and $323 million posted in support of our proportionate share of capital commitments in connection with the Sandy Creek Project. These additional postings were partially offset by the release of Independence restricted cash in exchange for the posting of a letter of credit. The decrease in restricted cash of $121 million during the twelve months ended December 31, 2006 related primarily to the return of our $335 million deposit associated with our former cash collateralized facility, offset by a $200 million deposit associated with our new cash collateralized facility and a $14 million increase in the Independence restricted cash balance.

Table of Contents

Finally, Other included $7 million of insurance proceeds and $4 million of proceeds from the liquidation of an investment during the year ended December 31, 2008. Other included $11 million of proceeds related to an interconnection agreement offset by $3 million of sales and use taxes during the year ended December 31, 2006.

Financing Activities

Historical Cash Flow from Financing Activities. Dynegy s net cash provided by financing activities during the twelve months ended December 31, 2008 totaled $148 million. DHI s net cash provided by financing activities during the twelve months ended December 31, 2008 totaled $146 million, which primarily related to $192 million of proceeds from long-term borrowings under the Plum Point Credit Agreement Facility, partly offset by a $45 million principal payment on our 9.00 percent Sithe secured bonds due 2013.

Dynegy s net cash provided by financing activities during the twelve months ended December 31, 2007 totaled $433 million, which primarily related to $2,758 million of proceeds from long-term borrowings, net of approximately $35 million of debt issuance costs, partially offset by $2,320 million of payments.

DHI s net cash provided by financing activities during the twelve months ended December 31, 2007 totaled $369 million, which primarily related to $2,758 million of proceeds from long-term borrowings, net of approximately $35 million of debt issuance costs, partially offset by $2,045 million of payments. Cash used in financing activities includes dividend payments of $342 million to Dynegy.

Dynegy s net cash used in financing activities during the twelve months ended December 31, 2006 totaled $1,342 million, which primarily related to $1,930 million of payments, partially offset by $1,071 million of proceeds from long-term borrowings, net of approximately $29 million of debt issuance costs. In addition, Dynegy had debt conversion costs of $249 million and paid $400 million in cash, plus accrued and unpaid dividends totaling approximately $6.3 million, to redeem the Series C Preferred in May 2006. Proceeds from the issuance of common stock consisted primarily of approximately $178 million from a public offering of 40.25 million shares of Dynegy s Class A common stock at $4.60 per share, net of underwriting fees. Dividend payments totaling $17 million were also made on our Series C Preferred prior to its redemption.

DHI s net cash used in financing activities during the twelve months ended December 31, 2006 totaled $1,235 million, which primarily related to $1,930 million of payments, partially offset by $1,071 million of proceeds from long-term borrowings, net of approximately $29 million of debt issuance costs. In addition, DHI had debt conversion costs of $204 million and payments to Dynegy of $170 million, which consists of repayments of borrowings of $120 million and a one-time dividend payment of $50 million.

Table of Contents

Summarized Debt and Other Obligations. The following table depicts our consolidated third party debt obligations, including the present value of the DNE leveraged lease payments discounted at 10 percent, and the extent to which they are secured as of December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
	(in millions)	
First secured obligations	$ 919	$ 920
Unsecured obligations	4,945	5,015
Total corporate obligations	5,864	5,935
Secured non-recourse obligations (1)	959	806
Total obligations	6,823	6,741
Less: DNE lease financing (2)	(700)	(770)
Other (3)	13	19
Total notes payable and long-term debt (4)	$ 6,136	$ 5,990

(1) Includes PPEA s non-recourse project financing of $515 million and tax-exempt bonds of $100 million for its share of the construction of the Plum Point facility. Although we own a 37 percent economic interest in PPEA, we consolidate PPEA and its debt, as we are the primary beneficiary of this VIE. Also includes project financing associated with

our Independence facility. Please read Note 12 Variable Interest Entities for further discussion.

(2) Represents present value of future lease payments discounted at 10 percent.

(3) Consists of net premiums on debt of $13 million and $19 million at December 31, 2008 and 2007, respectively.

(4) Does not include letters of credit.

During 2008, we continued our efforts to enhance our capital structure flexibility. In June 2008, DHI entered into a Facility and Security Agreement (the Contingent LC Facility) with Morgan Stanley Capital Group Inc. (Morgan Stanley), as lender, issuing bank, collateral agent and paying agent. Availability under the Contingent LC Facility is contingent on natural gas prices rising above $13/MMBtu during 2009. For every dollar increase above $13/MMBtu in 2009 forward natural gas prices, $40 million in capacity will initially be available, up to a total of $300 million. In the event that the Contingent LC Facility is utilized, it will complement existing liquidity instruments as a source of additional letters of credit to meet our collateral requirements. Letter of credit availability will accrue ongoing fees at an annual rate of 3.2 percent. Over the course of 2009, the ratio of availability per dollar increase in natural gas prices will be reduced, on a pro rata monthly basis, to zero by year-end. Should forward natural gas and electricity prices increase to levels that are in excess of the forward prices experienced at June 30, 2008, creating the need for us to post significantly more collateral for our forward power sales or natural gas purchases, we believe cash flow from operations and available borrowings under our credit facilities (including the Contingent LC Facility) will be sufficient to meet our liquidity needs in the coming twelve months. Such letters of credit will be available for the purpose of supporting certain commercial and trading contracts and related netting agreements described in the Credit Agreement. As of December 31, 2008, no amounts were available under the Contingent LC Facility.

Additionally, during 2008, certain commodity counterparties were granted liens pari-passu with lenders under the Fifth Amended and Restated Credit Agreement. The first liens were granted in lieu of other forms of collateral we may have needed to provide in support of commodity transactions. As of December 31, 2008, our net discounted exposure on the agreements collateralized by liens was approximately $39 million.

In September 2008, LBH filed for protection from creditors under Chapter 11 bankruptcy law. Lehman CP, the Lehman entity acting as one of our lenders for the revolving portion of our Credit Agreement, was not initially part of the bankruptcy estate. However, in early October 2008, Lehman CP also filed for protection from creditors under the bankruptcy law. Lehman CP s lending obligations were not assumed by Barclays, which had acquired most of

Lehman s North American banking operations in September 2008. The bankruptcy filing increases the likelihood that Lehman CP will not fund any borrowing requests under our Credit Agreement, thereby reducing our effective availability under the Credit Agreement by $70 million to $1.9 billion.

Please read Note 15 Debt for further discussion of these items. Following these transactions, our debt maturity profile as of December 31, 2008 includes $64 million in 2009, $68 million in 2010, $575 million in 2011, $582 million in 2012, $1,004 million in 2013 and approximately $3,843 million thereafter. Maturities for 2009 represent principal payments on the Sithe Senior Notes.

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, although certain interest rate swaps to which Plum Point is a party could be terminated if a credit downgrade of Plum Point occurs and there is also a default by the insurer that has provided credit insurance for the swaps.

Financial Covenants. Our Fifth Amended and Restated Credit Agreement contains certain financial covenants, including (i) a covenant (measured as of the last day of the relevant fiscal quarter as specified below) that requires DHI and certain of its subsidiaries to maintain a ratio of secured debt to adjusted EBITDA for DHI and its relevant subsidiaries of no greater than 2.75:1 (December 31, 2008 and March 31, 2009); and 2.5:1 (June 30, 2009 and thereafter); and (ii) a covenant that requires DHI and certain of its subsidiaries to maintain a ratio of adjusted EBITDA to consolidated interest expense for DHI and its relevant subsidiaries as of the last day of the measurement periods ending December 31, 2008 of no less than 1.5:1; ending March 31, 2009 and June 30, 2009 of no less than 1.625:1; and ending September 30, 2009 and thereafter of no less than 1.75:1. We are in compliance with these covenants as of December 31, 2008. In addition, we expect to be in compliance with these covenants in the near- and long-term based on management s forecast of financial performance of the markets in which we operate. However, based on management s current forecast of financial performance during 2009, DHI s available liquidity under the Fifth Amended and Restated Credit Facility may be reduced temporarily in order to remain in compliance with the secured debt to adjusted EBITDA ratio.

Subject to certain exceptions, DHI and its relevant subsidiaries are subject to restrictions on asset sales incurring additional indebtedness, limitations on investments and certain limitations on dividends and other payments in respect of capital stock. Our lenders agreed to amend certain of these restrictions or limitations effective as of February 13, 2009. Based on our available liquidity as of December 31, 2008 and the additional capacity available under the Contingent LC Facility, we do not believe these limitations will affect our liquidity. Please read Note 15 Debt Fifth Amended and Restated Credit Facility for further discussion of our amended credit facility.

Capital-Raising Transactions. As part of our ongoing efforts to maintain a capital structure that is closely aligned with the cash-generating potential of our asset-based business, which is subject to cyclical changes in commodity prices, we may explore additional sources of external liquidity. The timing of any transaction may be impacted by events, such as strategic growth opportunities, legal judgments or regulatory requirements, which could require us to pursue additional capital in the near term. The receptiveness of the capital markets to an offering of debt or equity securities 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, including current market conditions. Any issuance of equity by Dynegy likely would have other effects as well, including stockholder dilution. Our ability to issue debt securities is limited by our financing agreements, including the Credit Agreement, as amended. Please read Note 15 Debt for further discussion.

In addition, we continually review and discuss opportunities to participate in what we believe will be continuing consolidation of the power generation industry. No such definitive transaction has been agreed to and none can be guaranteed to occur; however, we have successfully executed on similar opportunities in the past and could do so again in the future. Depending on the terms and structure of any such transaction, we could issue significant debt and/or equity securities for capital-raising purposes. We also could be required to assume substantial debt obligations and the underlying payment obligations.

Capital Allocation. We continually review our investment options with respect to our capital resources. We do not have any material debt maturities until 2011, and between now and then we expect to enhance our current capital resources through the results of our operating business. We will seek to invest these capital resources in various projects and activities based on their return to stockholders. Potential investments could include, among others: add-on or other enhancement projects associated with our current power generation assets; brownfield development projects; merger and acquisition activities; returns of capital to stockholders and early repayment or repurchase of debt. Any such future purchases of debt may be made through open market or privately negotiated transactions with third parties or pursuant to one or more tender or exchange offers or otherwise, upon such terms and at such prices as we may determine. Capital allocation determinations generally are subject to the discretion of Dynegy s Board of Directors as well as availability of capital and related investment opportunities, and may be limited by the provisions of our financing agreements. Any particular use of capital in an amount that is not considered material may be made without any prior public disclosure and could occur at any time.

Table of Contents

Dividends on Dynegy Common Stock. Dividend payments on Dynegy s common stock are at the discretion of its Board of Directors. Dynegy did not declare or pay a dividend on its common stock for the year ended December 31, 2008 and it does not expect to pay a dividend on any class of its common stock in the foreseeable future.

Credit Ratings

Our credit rating status is currently non-investment grade; our senior unsecured debt is rated B by Standard & Poor s, B2 by Moody s, and B+ by Fitch. Over the past several years, we have established a successful record of accomplishment with the financial community. Specifically, we have made timely principal and interest payments, complied with our debt covenants and followed a disciplined approach to managing our capital structure while ensuring our growth and profitability. As a result, we do not expect a credit rating downgrade in the foreseeable future. However, any future downgrade of our credit rating, if one were to occur, would not have a material impact on our collateral posting requirements, nor would such a downgrade impact any of our debt covenants or the timing of our debt maturities.

Disclosure of Contractual Obligations and Contingent Financial Commitments

We have incurred various 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 revenue-producing activities. Contingent financial commitments represent obligations that become payable only if specified events occur, such as financial guarantees. Details on these obligations are set forth below.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2008. Cash obligations reflected are not discounted and do not include accretion or dividends.

		Expiration by Period			
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
			(in millions)		
Long-term debt (including current portion)	$ 6,136	$ 64	$ 643	$ 1,586	$ 3,843
Interest payments on debt	3,148	419	755	676	1,298
Operating leases	1,196	171	258	355	412
Capital leases	12	2	4	4	2
Capacity payments	345	46	95	92	112
Transmission obligations	193	6	12	12	163
Interconnection obligations	19	1	2	2	14
Construction service agreements	877	39	142	123	573
Pension funding obligations	80	27	53		
Other obligations	41	14	10	6	11
Total contractual obligations	$ 12,047	$ 789	$ 1,974	$ 2,856	$ 6,428

Long-Term Debt (Including Current Portion). Total amounts of Long-term debt (including current portion) are included in the December 31, 2008 consolidated balance sheet. Please read Note 15 Debt for further discussion.

Interest Payments on Debt. Interest payments on debt represent periodic interest payment obligations associated with our long-term debt (including current portion). Please read Note 15 Debt for further discussion.

Operating Leases. Operating leases includes the minimum lease payment obligations associated with our DNE leveraged lease. Please read Liquidity and Capital Resources Off-Balance Sheet Arrangements DNE Leveraged Lease for further discussion. 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 two VLGCs previously utilized in our former global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $14 million each year for the years 2009 through 2012, and approximately $17 million from 2013 through lease expiration. The charter party rates payable under the two charter party agreements vary in accordance with market-based rates for similar shipping services. The $14 million and $17 million amounts set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary terms of the charter party agreements expire September 2013 and September 2014, respectively. On January 1, 2003, in connection with the sale of our global liquids business, we sub-chartered both VLGCs to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. We continue to rely on the sub-charters with a subsidiary of Transammonia to satisfy the obligations of our two charter party agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements.

Capital Leases. In January 2006, we entered into an obligation under a capital lease related to a coal loading facility, which is used in the transportation of coal to our Vermilion power generating facility. Pursuant to our agreement with the lessor, we are obligated for minimum payments in the aggregate amount of $12 million over the remaining term of the lease.

Capacity Payments. Capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $345 million.

Transmission Obligations. Transmission obligations represent an obligation with respect to transmission services for our Griffith facility. This agreement expires in 2039. Our obligation under this agreement is approximately $6 million per year through the term of the contract.

Interconnection Obligations. Interconnection obligations represent an obligation with respect to interconnection services for our Ontelaunee facility. This agreement expires in 2025. Our obligation under this agreement is approximately $1 million per year through the term of the contract.

Construction Service Agreements. Construction service agreements represent obligations with respect to long-term service agreements. Our obligation under these agreements is approximately $877 million.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations for 2009 $27 million, 2010 $24 million and 2011 $29 million. These amounts reflect increases over prior amounts resulting from declines in investor performance as a result of the ongoing turmoil in the debt and equity markets. Although we expect to continue to incur funding obligations subsequent to 2011, we cannot confidently estimate the amount of such obligations at this time and, therefore, have not included them in the table above.

Other Obligations. Other obligations include the following items:

- A payment of $8.5 million in 2009 related to Illinois rate relief legislation. Please read Note 19 Commitments and Contingencies Illinois Auction Complaints for further discussion;
- Payments associated with a capacity contract between Independence and Con Edison. The aggregate payments through the 2014 expiration are approximately $13 million as of December 31, 2008;
- $6 million of reserves recorded in connection with FIN No. 48, Accounting for Uncertainty in Income Taxes (FIN No. 48). Please read Note 17 Income Taxes Unrecognized Tax Benefits for further discussion;

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 $7 million as of December 31, 2008; and

Agreements for the supply of water to our generating facilities.

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2008 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)	$ 1,135	$ 835	$ 300	$	$
Surety bonds (2)	7	7			
Total financial commitments	$ 1,142	$ 842	$ 300	$	$

(1) Amounts include outstanding letters of credit.

(2) Surety bonds are generally on a rolling 12-month basis. The $7 million of surety bonds are supported by collateral.

Off-Balance Sheet Arrangements

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

As of December 31, 2008, future lease payments are $141 million for 2009, $95 million for 2010, $112 million for 2011, $179 million for 2012, $142 million for 2013, $143 million for 2014 and $248 million in the aggregate due from 2015 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, 2008, the present value (discounted at 10 percent) of future lease payments was $700 million.

Table of Contents

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

	2008	2007	2006
		(in millions)	
Lease Expense	$ 50	$ 50	$ 50
Lease Payments (Cash Flows)	$ 144	$ 107	$ 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 compensate the lessor for termination of the lease, including redeeming 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, 2008, the termination payment at par would be approximately $930 million for all of the leased 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 leased 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.

Commitments and Contingencies

Please read Note 19 Commitments and Contingencies, which is incorporated herein by reference, for further discussion of our material commitments and contingencies.

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 the years ended December 31, 2008, 2007 and 2006. At the end of this section, we have included our business outlook for each segment.

We report results of our power generation business as three separate geographical segments as follows: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. Beginning in the first quarter 2008, the results of our former customer risk management business are included in Other as it did not meet the criteria required to be an operating segment as of January 1, 2008. Accordingly, we have restated the corresponding items of segment information for prior periods. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization. Dynegy s 50 percent investment in DLS Power Development, which was terminated effective January 1, 2009, is included in Other for segment reporting.

Table of Contents

Summary Financial Information. The following tables provide summary financial data regarding Dynegy s consolidated and segmented results of operations for 2008, 2007 and 2006, respectively.

Dynegy s Results of Operations for the Year Ended December 31, 2008

	Power Generation				
	GEN-MW	**GEN-WE**	**GEN-NE**	**Other**	**Total**
			(in millions)		
Revenues	$ 1,623	$ 925	$ 1,006	$ (5)	$ 3,549
Cost of sales	(584)	(574)	(705)	10	(1,853)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(205)	(124)	(180)	15	(494)
Depreciation and amortization expense	(206)	(101)	(54)	(10)	(371)
Impairment and other charges		(47)			(47)
Gain on sale of assets	56	11		15	82
General and administrative expense				(157)	(157)
Operating income (loss)	$ 684	$ 90	$ 67	$ (132)	$ 709
Losses from unconsolidated investments		(40)		(83)	(123)
Other items, net	3	5	6	73	87
Interest expense					(427)
Income from continuing operations before income taxes					246
Income tax expense					(75)
Income from continuing operations					171
Income from discontinued operations, net of taxes					3
Net income					$ 174

Table of Contents

Dynegy s Results of Operations for the Year Ended December 31, 2007

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$ 1,325	$ 689	$ 1,076	$ 13	$ 3,103
Cost of sales	(482)	(400)	(688)	19	(1,551)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(193)	(86)	(179)	(4)	(462)
Depreciation and amortization expense	(194)	(73)	(45)	(13)	(325)
Gain on sale of assets	39			4	43
General and administrative expense				(203)	(203)
Operating income (loss)	$ 495	$ 130	$ 164	$ (184)	$ 605
Earnings (losses) from unconsolidated investments		6		(9)	(3)
Other items, net	(7)			56	49
Interest expense					(384)
Income from continuing operations before income taxes					267
Income tax expense					(151)
Income from continuing operations					116
Income from discontinued operations, net of taxes					148
Net income					$ 264

Table of Contents

Dynegy s Results of Operations for the Year Ended December 31, 2006

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$ 969	$ 87	$ 609	$ 105	$ 1,770
Cost of sales	(318)	(66)	(370)	(44)	(798)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(165)	(6)	(160)	(7)	(338)
Depreciation and amortization expense	(168)	(8)	(24)	(17)	(217)
Impairment and other charges	(110)	(9)			(119)
Gain on sale of assets				3	3
General and administrative expense				(196)	(196)
Operating income (loss)	$ 208	$ (2)	$ 55	$ (156)	$ 105
Losses from unconsolidated investments		(1)			(1)
Other items, net	2	1	9	42	54
Interest expense and debt conversion costs					(631)
Loss from continuing operations before income taxes					(473)
Income tax benefit					152
Loss from continuing operations					(321)
Loss from discontinued operations, net of taxes					(13)
Cumulative effect of change in accounting principle, net of taxes					1
Net loss					$ (333)

Table of Contents

The following tables provide summary financial data regarding DHI s consolidated and segmented results of operations for 2008, 2007 and 2006, respectively.

DHI s Results of Operations for the Year Ended December 31, 2008

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$ 1,623	$ 925	$ 1,006	$ (5)	$ 3,549
Cost of sales	(584)	(574)	(705)	10	(1,853)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(205)	(124)	(180)	15	(494)
Depreciation and amortization expense	(206)	(101)	(54)	(10)	(371)
Impairment and other charges		(47)			(47)
Gain on sale of assets	56	11		15	82
General and administrative expense				(157)	(157)
Operating income (loss)	$ 684	$ 90	$ 67	$ (132)	$ 709
Losses from unconsolidated investments		(40)			(40)
Other items, net	3	5	6	72	86
Interest expense					(427)
Income from continuing operations before income taxes					328
Income tax expense					(123)
Income from continuing operations					205
Income from discontinued operations, net of taxes					3
Net income					$ 208

Table of Contents

DHI s Results of Operations for the Year Ended December 31, 2007

	Power Generation GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$ 1,325	$ 689	$ 1,076	$ 13	$ 3,103
Cost of sales	(482)	(400)	(688)	19	(1,551)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(193)	(86)	(179)	(4)	(462)
Depreciation and amortization expense	(194)	(73)	(45)	(13)	(325)
Gain on sale of assets	39			4	43
General and administrative expense				(184)	(184)
Operating income (loss)	$ 495	$ 130	$ 164	$ (165)	$ 624
Earnings from unconsolidated investments		6			6
Other items, net	(7)			53	46
Interest expense					(384)
Income from continuing operations before income taxes					292
Income tax expense					(116)
Income from continuing operations					176
Income from discontinued operations, net of taxes					148
Net income					$ 324

DHI s Results of Operations for the Year Ended December 31, 2006

	Power Generation GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$ 969	$ 87	$ 609	$ 105	$ 1,770
Cost of sales	(318)	(66)	(370)	(44)	(798)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(165)	(6)	(160)	(7)	(338)
Depreciation and amortization expense	(168)	(8)	(24)	(17)	(217)
Impairment and other charges	(110)	(9)			(119)

Gain on sale of assets								3		3
General and administrative expense								(193)		(193)
Operating income (loss)	$	208	$	(2)	$	55	$	(153)	$	108
Losses from unconsolidated investments				(1)						(1)
Other items, net		2		1		9		39		51
Interest expense and debt conversion costs										(579)
Loss from continuing operations before income taxes										(421)
Income tax benefit										125
Loss from continuing operations										(296)
Loss from discontinued operations, net of taxes										(12)
Net loss									$	(308)

Table of Contents

The following table provides summary segments operating statistics for the years ended December 31, 2008, 2007 and 2006, respectively:

	Year Ended December 31, 2008	2007	2006
GEN-MW			
Million Megawatt Hours Generated	24.5	25.0	21.5
In Market Availability for Coal Fired Facilities (1)	90%	93%	89%
Average Capacity Factor for Combined Cycle Facilities (2)	16%	19%	
Average Quoted On-Peak Market Power Prices ($/MWh) (3):			
Cinergy (Cin Hub)	$ 67	$ 61	$ 52
Commonwealth Edison (NI Hub)	$ 66	$ 59	$ 52
PJM West	$ 84	$ 71	$ 62
Average On-Peak Market Spark Spreads ($/MWh) (4):			
PJM West	15	17	10
GEN-WE			
Million Megawatt Hours Generated (5) (6)	11.2	11.1	0.9
Average Capacity Factor for Combined Cycle Facilities (2)	44%	59%	
Average Quoted On-Peak Market Power Prices ($/MWh) (3):			
North Path 15 (NP 15)	$ 80	$ 67	$ 61
Palo Verde	$ 72	$ 62	$ 58
Average On-Peak Market Spark Spreads ($/MWh) (4):			
North Path 15 (NP 15)	$ 18	$ 16	$ 14
Palo Verde	$ 13	$ 13	$ 12
GEN-NE			
Million Megawatt Hours Generated	7.9	9.4	4.4
In Market Availability for Coal Fired Facilities (1)	91%	90%	86%
Average Capacity Factor for Combined Cycle Facilities (2)	25%	37%	17%
Average Quoted On-Peak Market Power Prices ($/MWh) (3):			
New York Zone G	$ 101	$ 84	$ 76
New York Zone A	$ 68	$ 64	$ 59
Mass Hub	$ 91	$ 78	$ 70
Average On-Peak Market Spark Spreads ($/MWh) (4):			
New York Zone A	$ 3	$ 12	$ 9
Mass Hub	$ 23	$ 23	$ 19
Fuel Oil	$ (37)	$ (16)	$ (10)
Average natural gas price Henry Hub ($/MMBtu) (7)	$ 8.85	$ 6.95	$ 6.74

(1) Reflects the percentage of generation available during periods when market prices are such that

these units could be profitably dispatched.

(2) Reflects actual production as a percentage of available capacity.

(3) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices realized by the Company.

(4) Reflects the simple average of the spark spread available to a 7.0 MMBtu/MWh heat rate generator selling power at day-ahead prices and buying delivered natural gas or fuel oil at a daily cash market price and does not reflect spark spreads available to the Company.

(5) Includes our ownership percentage in the MWh generated by

our GEN-WE investment in the Black Mountain power generation facility for the years ended December 31, 2008, 2007 and 2006, respectively.

(6) Excludes approximately 1.8 million MWh and 2.9 million MWh generated by our CoGen Lyondell power generation facility, which we sold in August 2007, for the years ended December 31, 2007 and 2006 and less than 0.1 million MWh generated by our Calcasieu power generation facility, which we sold on March 31, 2008, for the years ended December 31, 2008, 2007 and 2006.

(7) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by the

Company.

Table of Contents

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, 2008				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE (in millions)	Other	Total
Gain on sale of Rolling Hills	$ 56	$	$	$	$ 56
Asset impairment		(47)			(47)
Release of state franchise tax and sales tax liability				16	16
Gain on sale of NYMEX shares				15	15
Gain on sale of Oyster Creek ownership interest		11			11
Gain on sale of Sandy Creek ownership interest		13			13
Gain on liquidation of foreign entity				24	24
Sandy Creek mark-to-market losses (1)		(40)			(40)
Taxes (2)				12	12
Total DHI	$ 56	$ (63)	$	$ 67	$ 60
Impairment of equity investment				(24)	(24)
Loss on dissolution of equity investment				(47)	(47)
Taxes (2)				6	6
Total Dynegy	$ 56	$ (63)	$	$ 2	$ (5)

(1) These mark-to-market losses represent our 50 percent share.

(2) Represents the benefit of adjustments arising from the measurement of temporary differences.

	Year Ended December 31, 2007
	Power Generation

	GEN-MW	GEN-WE	GEN-NE (in millions)	Other	Total
Discontinued operations (1)	$	$ 225	$	$ 14	$ 239
Legal and settlement charges				(17)	(17)
Illinois rate relief charge	(25)				(25)
Change in fair value of interest rate swaps, net of minority interest	(9)			39	30
Gain on sale of Sandy Creek ownership interest		10			10
Gain on sale of Plum Point ownership interest	39				39
Settlement of Kendall toll				31	31
Taxes				30	30
Total DHI	5	235		97	337
Legal and settlement charges				(19)	(19)
Taxes				(20)	(20)
Total Dynegy	$ 5	$ 235	$	$ 58	$ 298

(1) Discontinued operations for GEN-WE includes a gain of $224 million on the sale of the CoGen Lyondell power generation facility.

	Year Ended December 31, 2006				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Debt conversion costs	$	$	$	$ (204)	$ (204)
Asset impairments	(110)	(9)			(119)
Legal and settlement charges				(53)	(53)
Sithe Subordinated Debt exchange charge			(36)		(36)
Acceleration of financing costs				(34)	(34)
Taxes				(29)	(29)
Discontinued operations		(53)		29	(24)
Total DHI	(110)	(62)	(36)	(291)	(499)
Debt conversion costs				(45)	(45)
Acceleration of financing costs				(2)	(2)
Discontinued operations				1	1
Total Dynegy	$ (110)	$ (62)	$ (36)	$ (337)	$ (545)

Year Ended 2008 Compared to Year Ended 2007

Operating Income

Operating income for Dynegy was $709 million for the year ended December 31, 2008, compared to $605 million for the year ended December 31, 2007. Operating income for DHI was $709 million for the year ended December 31, 2008, compared to $624 million for the year ended December 31, 2007.

Our operating income for the year ended December 31, 2008 was driven, in part, by mark-to-market gains on forward sales of power associated with our generating assets, which are included in Revenues in the consolidated statements of operations. Such gains, which totaled $253 million for the year ended December 31, 2008, were a result of a decrease in forward market power prices or forward spark spreads during 2008 combined with greater outstanding notional amounts of forward positions compared to the same period in the prior year. Effective April 2, 2007, we chose to cease designating our commodity derivative instruments as cash flow hedges for accounting purposes. Please read Note 6 Risk Management Activities, Derivatives and Financial Instruments for further discussion. The resulting mark-to-market accounting treatment results in the immediate recognition of gains and losses within Revenues in the consolidated statements of operations due to changes in the fair value of the derivative instruments. These mark-to-market gains and losses are not reflected in the consolidated statements of operations in the same period as the underlying power sales from generation activity for which the derivative instruments serve as economic hedges. Except for those positions that settled in the year ended December 31, 2008, the expected cash impact of the settlement of these positions will be recognized over time through the end of 2010 based on the prices at which such positions are contracted. Our overall mark-to-market position and the related mark-to-market value will change as we buy or sell volumes within the forward market and as forward commodity prices fluctuate.

Power Generation Midwest Segment. Operating income for GEN-MW was $684 million for the year ended December 31, 2008, compared to $495 million for the year ended December 31, 2007.

Revenues for the year ended December 31, 2008 increased by $298 million compared to the year ended December 31, 2007, cost of sales increased by $102 million and operating and maintenance expense increased by $12 million, resulting in a net increase of $184 million. The increase was primarily driven by the following:

Mark-to-market gains GEN-MW s results for the year ended December 31, 2008 included mark-to-market gains of $191 million, compared to $36 million of mark-to-market losses for the year ended December 31, 2007. Of the $191 million in 2008 mark-to-market gains, $5 million related to positions that settled in 2008, and the remaining $186 million related to positions that will settle in 2009 and 2010;

Kendall and Ontelaunee provided results of $109 million for the year ended December 31, 2008 compared to $62 million for the year ended December 31, 2007, exclusive of mark-to-market amounts discussed above. The improved results in 2008 are the result of higher energy and capacity prices in PJM, and twelve months of results in 2008 compared with nine months in 2007, as the assets were acquired April 2, 2007;

- Increased market prices The average quoted on-peak prices in the Cin Hub and PJM West pricing regions (the liquid market hubs where our forward power sales occurred) increased from $61 and $71 per MWh, respectively, for the year ended December 31, 2007 to $67 and $84 per MWh, respectively, for the year ended December 31, 2008;
- Additional capacity sales of approximately $35 million, as a result of improved capacity prices for 2008 compared with 2007; and
- In 2007, we recorded a pre-tax charge of $25 million in Cost of sales to support a rate relief package for Illinois electric consumers.

These items were offset by the following:

- Decreased volumes In spite of the addition of the Midwest plants acquired through the Merger on April 2, 2007, generated volumes decreased by 2 percent, from 25 million MWh for the year ended December 30, 2007, to 24.5 million MWh for the year ended December 31, 2008. The decrease in volumes was primarily driven by forced outages, lower off-peak volumes due to mild temperatures and transmission congestion as a result of flooding;
- Increased fuel costs, due largely to higher natural gas prices; and
- Wider basis differentials In 2008, the price differential between the locations where we deliver generated power and the liquid market hubs where our forward power sales occurred was wider, in part due to congestion and transmission outages and regional weather differences, as compared to the same period in the prior year. These wider price differentials had a negative impact on our results as the price we received for delivered power at our physical delivery locations did not increase to the same extent as that of the liquid traded hubs.

Depreciation expense increased from $194 million for the year ended December 31, 2007 to $206 million for the year ended December 31, 2008, primarily as a result of the addition of Kendall and Ontelaunee.

Operating income for the year ended December 31, 2008 included a $56 million pre-tax gain from the sale of our Rolling Hills power generation facility, reflected in Gain on sale of assets in our consolidated statements of operations. Operating income for the year ended December 31, 2007 included a $39 million pre-tax gain related to the sale of a portion of our ownership interest in PPEA Holdings.

Power Generation West Segment. Operating income for GEN-WE was $90 million for the year ended December 31, 2008, compared to operating income of $130 million for the year ended December 31, 2007. Such amounts do not include results from the CoGen Lyondell and Calcasieu power generation facilities, which have been classified as discontinued operations for periods presented prior to disposition.

Revenues for the year ended December 31, 2008 increased by $236 million compared to the year ended December 31, 2007, cost of sales increased by $174 million and operating and maintenance expense increased by $38 million, resulting in a net increase of $24 million. The increase was primarily driven by the following:

- Mark-to-market gains GEN-WE s results for the year ended December 31, 2008 included mark-to-market gains of $51 million, compared to $44 million of mark-to-market gains for the year ended December 31, 2007. Of the $51 million in 2008 mark-to-market gains, $3 million of losses related to positions that settled in 2008, and the remaining $54 million related to positions that will settle in 2009 and 2010; and
- Increased volumes Generated volumes were 11.2 million MWh for the year ended December 31, 2008, up from 11.1 million MWh for the year ended December 31, 2007. The volume increase was primarily driven by the West plants acquired on April 2, 2007, which provided total results, including operating expense, of $177 million for the year ended December 31, 2008, compared with $156 million for the same period in 2007, exclusive of mark-to-market amounts discussed above. Results for 2008 were negatively impacted by a forced outage and increased fuel costs due to higher natural gas prices.

Table of Contents

In May 2008, we sold a beneficial interest in Oyster Creek Limited to General Electric for approximately $11 million, and recognized a gain on the sale of approximately $11 million, reflected in Gain on sale of assets in our consolidated statements of operations. In addition, during 2008, we recorded a $47 million impairment of our Heard County power generating facility, reflected in Impairment and other charges in our consolidated statements of operations.

Depreciation expense increased from $73 million for the year ended December 31, 2007 to $101 million for year ended December 31, 2008 primarily as a result of the addition of the acquired plants.

Power Generation Northeast Segment. Operating income for GEN-NE was $67 million for the year ended December 31, 2008, compared to $164 million for the year ended December 31, 2007.

Revenues for the year ended December 31, 2008 decreased by $70 million compared to the year ended December 31, 2007, cost of sales increased by $17 million and operating and maintenance expense increased by $1 million, resulting in a net decrease of $88 million. The decrease was primarily driven by the following:

- Decreased spark spreads Although on-peak market power prices in New York Zone A increased by 7 percent, Zone A spark spreads contracted as fuel prices rose at a greater rate than power prices;
- Decreased volumes In spite of the addition of the Northeast plants acquired through the Merger on April 2, 2007, generated volumes decreased by 16 percent, from 9.4 million MWh for the year ended December 31, 2007 to 7.9 million MWh for the year ended December 31, 2008. The volumes added by the new Northeast plants were more than offset by declines due to decreased spark spreads and reduced dispatch opportunities as compared to the same period in the prior year;
- Decreased results from the Bridgeport and Casco Bay assets, which provided results of $42 million for the year ended December 31, 2008, compared with $90 million for the year ended December 31, 2007, exclusive of mark-to-market amounts discussed below. Although the Bridgeport and Casco Bay assets provided a full year of results in 2008 compared with nine months in 2007, volumes were down during the key summer months as a result of compressed spark spreads and reduced dispatch opportunities;
- Decreased capacity sales of approximately $15 million, exclusive of the Bridgeport and Casco Bay results discussed above, as a result of lower capacity prices for 2008 compared with 2007; and
- Increased fuel cost, due largely to higher coal prices for our Danskammer facility.

These items were partially offset by mark-to-market gains. GEN-NE s results for the year ended December 31, 2008 included mark-to-market gains of $11 million, compared to mark to market losses of $40 million for the year ended December 31, 2007. Of the $11 million in 2008 mark-to-market gains, $3 million related to positions that settled in 2008, and the remaining $8 million related to positions that will settle in 2009 and 2010.

Depreciation expense increased from $45 million for the year ended December 31, 2007 to $54 million for the year ended December 31, 2008, primarily as a result of the addition of Bridgeport and Casco Bay.

Other. Dynegy s other operating loss for the year ended December 31, 2008 was $132 million, compared to an operating loss of $184 million for the year ended December 31, 2007. DHI s other operating loss for the year ended December 31, 2008 was $132 million, compared to an operating loss of $165 million for the year ended December 31, 2007. Operating losses in both periods were comprised primarily of general and administrative expenses offset by results from our former customer risk management business. Included in 2008 was an approximate $15 million gain related to our sale of our remaining NYMEX shares and both membership seats. Results for 2008 also included a benefit of approximately $16 million related to the release of liabilities for state franchise tax and sales taxes, as well as a $9 million benefit from the release of a liability associated with an assignment of a natural gas transportation contract. 2007 included a $31 million pre-tax gain associated with the acquisition of Kendall. Prior to the acquisition, Kendall held a power tolling contract with our CRM business. Upon completion of the Merger, this contract became an intercompany agreement, and was effectively eliminated on a consolidated basis, resulting in the $31 million gain. Please read Note 3 Business Combinations and Acquisitions LS Power Business Combination for further discussion.

Dynegy s consolidated general and administrative expenses were $157 million and $203 million for the year ended December 31, 2008 and 2007, respectively. General and administrative expenses for the year ended December 31, 2007 included legal and settlement charges of $36 million and a charge of approximately $6 million in connection with the accelerated vesting of restricted stock and stock option awards previously granted to employees, which vested in full upon closing of the Merger.

DHI s consolidated general and administrative expenses were $157 million and $184 million for the year ended December 31, 2008 and 2007, respectively. General and administrative expenses for the year ended December 31, 2007 includes legal and settlement charges of $17 million and a charge of approximately $6 million in connection with the accelerated vesting of restricted stock and stock option awards previously granted to employees, which vested in full upon closing of the Merger.

Earnings (Losses) from Unconsolidated Investments

Dynegy s losses from unconsolidated investments were $123 million for the year ended December 31, 2008 of which $83 million related to Dynegy s investment in DLS Power Development, included in Other. These losses included a $24 million impairment charge, a $47 million loss on dissolution as a result of our decision to dissolve this venture and $12 million of equity losses. GEN-WE recognized $40 million of losses related to its investment in the Sandy Creek Project. These losses were comprised of $53 million primarily associated with our share of the partnership s losses, partially offset by $13 million for our share of the gain on SCEA s sale of an 11 percent undivided interest in the Sandy Creek Project. The $53 million consisted of $40 million mark-to-market losses primarily related to interest rate swap contracts and $13 million of financing costs. Please read Note 12 Variable Interest Entities Sandy Creek for further discussion. Losses from unconsolidated investments were $3 million for the year ended December 31, 2007. GEN-WE recognized $6 million from the investment in Sandy Creek largely due to its $10 million share of the gain on SCEA s sale of a 25 percent undivided interest in the Sandy Creek Project. This income was more than offset by $9 million of losses related to Dynegy s interest in DLS Power Holdings.

DHI s losses from unconsolidated investments were $40 million for the year ended December 31, 2008 related to its investment in the Sandy Creek Project. These losses were comprised of $53 million primarily associated with our share of the partnership s losses, partially offset by our $13 million share of the gain on SCEA s sale of an 11 percent undivided interest in the Sandy Creek Project. The $53 million consisted of $40 million mark-to-market losses primarily related to interest rate swap contracts and $13 million of financing costs. Please read Note 12 Variable Interest Entities Sandy Creek for further discussion. Earnings from unconsolidated investments were $6 million for the year ended December 31, 2007. GEN-WE recognized $6 million from its investment in the Sandy Creek Project largely due to its $10 million share of the gain on SCEA s sale of a 25 percent undivided interest in the Sandy Creek Project.

Other Items, Net

Dynegy s other items, net, totaled $87 million of income for the year ended December 31, 2008, compared to $49 million of income for the year ended December 31, 2007. DHI s other items, net, totaled $86 million of income for the year ended December 31, 2008, compared to $46 million of income for the year ended December 31, 2007. We recorded a $24 million gain related to the liquidation of our investment in a foreign entity during 2008, as the amount accumulated in the translation adjustment component of equity related to that entity was recognized in income upon liquidation of the entity. Other items also included $3 million of minority interest income for the year ended December 31, 2008, compared with $7 million of minority interest expense recorded in 2007 related to the Plum Point development project. The change in minority interest income and expense is primarily related to the mark-to-market interest income recorded in 2007 related to the interest rate swap agreements associated with the Plum Point Credit Agreement. Please read Interest Expense below for further discussion. In addition, during the first quarter 2008, we recognized income of $6 million related to insurance proceeds received in excess of the book value of damaged assets. The remaining increase in other income was associated with higher interest income due to larger cash balances in 2008.

Table of Contents

Interest Expense

Our interest expense totaled $427 million for the year ended December 31, 2008, compared to $384 million for the year ended December 31, 2007. The increase was primarily attributable to the project debt assumed in connection with the Merger, which was subsequently replaced, and secondarily to the associated growth in the size and utilization of our Credit Agreement. Included in interest expense for the year ended December 31, 2007 was approximately $24 million of mark-to-market income from interest rate swap agreements associated with the Plum Point Term Facility. Effective July 1, 2007, these agreements were designated as cash flow hedges. Also included in interest expense for the year ended December 31, 2007 was approximately $12 million of income from interest rate swap agreements, prior to being terminated that were associated with the portion of the debt repaid in late May 2007. The mark-to-market income included in interest expense for 2007 is offset by net losses of approximately $7 million in connection with the repayment of a portion of the project indebtedness assumed in connection with the Merger.

Income Tax Expense

Dynegy reported an income tax expense from continuing operations of $75 million for the year ended December 31, 2008, compared to an income tax expense from continuing operations of $151 million for the year ended December 31, 2007. The 2008 effective tax rate was 30 percent, compared to 57 percent in 2007. Income tax expense from continuing operations for the year ended December 31, 2008 included a benefit of $10 million related to a permanent difference arising from a gain associated with the liquidation of a foreign entity. Additionally, income tax expense from continuing operations included a benefit of $18 million and expense of $21 million for the years ended December 31, 2008 and 2007, respectively, related to adjustments to state tax expense arising from the measurement of temporary differences. For the year ended December 31, 2007, Dynegy s higher effective state tax rate was driven by changes in levels of business activity in states in which we do business.

DHI reported an income tax expense from continuing operations of $123 million for the year ended December 31, 2008, compared to an income tax expense from continuing operations of $116 million for the year ended December 31, 2007. The 2008 effective tax rate was 38 percent, compared to 40 percent in 2007. Income tax expense from continuing operations for the year ended December 31, 2008 included a benefit of $10 million related to a permanent difference arising from a gain associated with the liquidation of a foreign entity. Additionally, income tax expense from continuing operations included a benefit of $12 million and expense of $19 million for the years ended December 31, 2008 and 2007, respectively, related to adjustments to state tax expense arising from the measurement of temporary differences. For the year ended December 31, 2007, DHI s higher effective state tax rate was driven by changes in levels of business activity in states in which we do business.

Discontinued Operations

Income From Discontinued Operations Before Taxes.

During the year ended December 31, 2008, Dynegy s pre-tax income from discontinued operations was $4 million ($3 million after-tax) which represents the receipt of business interruption insurance proceeds in Dynegy s former NGL segment. During the year ended December 31, 2007, Dynegy s pre-tax income from discontinued operations was $239 million ($148 million after-tax). Dynegy s GEN-WE segment included $225 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities in addition to a pre-tax gain of $224 million associated with the completion of our sale of the CoGen Lyondell power generation facility. Dynegy s U.K. CRM business included income of $15 million, primarily related to a favorable settlement of a legacy receivable.

During the year ended December 31, 2008, DHI s pre-tax income from discontinued operations was $4 million ($3 million after-tax) which represents the receipt of business interruption insurance proceeds in DHI s former NGL segment. During the year ended December 31, 2007, DHI s pre-tax income from discontinued operations was $240 million ($148 million after-tax). DHI s GEN-WE segment included $225 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities in addition to a pre-tax gain of $224 million associated with the completion of our sale of the CoGen Lyondell power generation facility. DHI s U.K. CRM business included income of $15 million, primarily related to a favorable settlement of a legacy receivable

Table of Contents

Income Tax Expense From Discontinued Operations

We recorded an income tax expense from discontinued operations of $1 million and $91 million during the years ended December 31, 2008 and 2007, respectively. The effective rates for the years ended December 31, 2008 and 2007 was 25 percent and 38 percent, respectively.

Year Ended 2007 Compared to Year Ended 2006

Operating Income

Operating income for Dynegy was $605 million for the year ended December 31, 2007, compared to $105 million for the year ended December 31, 2006. Operating income for DHI was $624 million for the year ended December 31, 2007, compared to $108 million for the year ended December 31, 2006.

Power Generation Midwest Segment. Operating income for GEN-MW was $495 million for the year ended December 31, 2007, compared to $208 million for the year ended December 31, 2006. Operating income for 2007 included a $39 million pre-tax gain related to the partial sale of our ownership interest in PPEA Holdings. Operating income for 2006 included a $110 million pre-tax impairment charge related to the Bluegrass generation facility, due to changes in the market that resulted in economic constraints on the facility.

Revenues for the year ended December 31, 2007 increased by $356 million compared to the year ended December 31, 2006, cost of sales increased by $164 million and operating and maintenance expense increased by $28 million, resulting in a net increase of $164 million. The increase was primarily driven by the following:

- Higher volumes Generated volumes increased by 16 percent, up from 21.5 million MWh for the year ended December 31, 2006 to 25 million MWh for the year ended December 31, 2007;
- Increased market prices The average quoted on-peak prices in Cin Hub pricing region increased from $52 per MWh for the year ended December 31, 2006 to $61 per MWh for the year ended December 31, 2007;
- Improved pricing as a result of the Illinois reverse power procurement auction Beginning January 1, 2007, we began operating under two new energy product supply agreements with subsidiaries of Ameren Corporation through our participation in the Illinois reverse power procurement auction in 2006. Under these new agreements, we provide up to 1,400 MWh around the clock for prices of approximately $64.77 per megawatt-hour; and
- The addition of the new Midwest plants acquired through the Merger The Kendall and Ontelaunee plants acquired on April 2, 2007 contributed to the increase in generated volumes and provided results of $62 million for the year ended December 31, 2007, exclusive of mark-to-market losses discussed below.

These items were offset by the following:

- Mark-to-market losses GEN-MW s results for the year ended December 31, 2007 included mark-to-market losses of $36 million related to forward sales, compared to $15 million of mark-to-market gains for the year ended December 31, 2006. Of the $36 million in 2007 mark-to-market losses, $13 million related to previously recognized mark-to-market gains that settled in 2007, and the remaining $23 million related to positions that will settle in 2008 and beyond. Please read Note 6 Risk Management Activities, Derivatives and Financial Instruments Accounting for Derivative Instruments and Hedging Activities Cash Flow Hedges for a discussion of our decision to no longer designate derivative transactions as cash flow hedges beginning with the second quarter 2007; and
- A $25 million charge related to the Illinois rate relief package In July 2007, we entered into agreements with various parties to make payments of up to $25 million in connection with legislation providing for rate relief for Illinois electric consumers. During September 2007, we made an initial payment of $7.5 million. During 2007, we recorded a pre-tax charge of $25 million, included as a cost of sales on our consolidated statements of operations.

Depreciation expense increased from $168 million for the year ended December 31, 2006 to $194 million for the year ended December 31, 2007, primarily as a result of the new Midwest plants and capital projects placed into service in 2006.

Power Generation West Segment. Operating income for GEN-WE was $130 million for the year ended December 31, 2007, compared to a loss of $2 million for the year ended December 31, 2006. The 2006 results relate to our Heard County and Rockingham generation facilities. Results from our CoGen Lyondell and Calcasieu power generation facilities have been classified as discontinued operations for all periods presented.

Revenues for the year ended December 31, 2007 increased by $602 million compared to the year ended December 31, 2006, cost of sales increased by $334 million and operating and maintenance expense increased by $80 million, resulting in a net increase of $188 million. The increase was primarily driven by the following:

- The addition of the new West plants acquired through the Merger Generated volumes were 11.1 million MWh for the year ended December 31, 2007, up from 0.9 million MWh for the year ended December 31, 2006. The volume increase was primarily driven by the new West plants, which provided total results of $156 million for the year ended December 31, 2007, exclusive of mark-to-market gains discussed below. The volume increase from the new West plants was slightly offset by a reduction due to the sale of the Rockingham generation facility in late 2006; and
- Mark-to-market gains GEN-WE s results for the year ended December 31, 2007 included mark-to-market gains of $44 million related to heat rate call-options and forward sales agreements, compared to zero for the year ended December 31, 2006. Of the $44 million in 2007 mark-to-market gains, $15 million related to risk management liabilities acquired in the Merger that settled in 2007, and the remaining $29 million related to positions that will settle in 2008 and beyond. Please read Note 6 Risk Management Activities, Derivatives and Financial Instruments Accounting for Derivative Instruments and Hedging Activities Cash Flow Hedges for a discussion of our decision to no longer designate derivative transactions as cash flow hedges beginning with the second quarter 2007.

Depreciation expense increased from $8 million for the year ended December 31, 2006 to $73 million for the year ended December 31, 2007 primarily as a result of the new West plants. In addition, during 2006, we recorded a $9 million impairment of our Rockingham facility, resulting from the announcement of our sale of the facility.

Power Generation Northeast Segment. Operating income for GEN-NE was $164 million for the year ended December 31, 2007, compared to $55 million for the year ended December 31, 2006.

Revenues for the year ended December 31, 2007 increased by $467 million compared to the year ended December 31, 2006, cost of sales increased by $318 million and operating and maintenance expense increased by $19 million, resulting in a net increase of $130 million. The increase was primarily driven by the following:

- Increased market prices and spark spreads On peak market prices in New York Zone G and Zone A increased by 11 percent and 8 percent, respectively. Spark spreads widened due to higher power prices. Average market spark spreads increased 33 percent and 21 percent for New York Zone A and Mass Hub, respectively;
- Higher volumes, partially driven by the addition of the new Northeast plants acquired through the Merger Generated volumes increased by 114 percent, up from 4.4 million MWh for the year ended December 31, 2006 to 9.4 million MWh for the year ended December 31, 2007. The volume increase was partially driven by the new Northeast plants. The Bridgeport and Casco Bay plants provided total results of $90 million for the year ended December 31, 2007, exclusive of mark-to-market losses discussed below. The volume increase was also a result of higher spark spreads and cooler weather in the first quarter 2007, which led to greater run times than in 2006; and
- A fuel oil inventory write-down of approximately $6 million was recorded in the year ended December 31, 2006.

Table of Contents

These items were offset by the following:

- Mark-to-market losses GEN-NE s results for the year ended December 31, 2007 included mark-to-market losses of $40 million related to forward sales, compared to losses of $26 million for the year ended December 31, 2006. Of the $40 million in 2007 mark-to-market losses, $32 million related to risk management assets acquired in the Merger that settled in 2007. The remaining $8 million related to positions that will settle in 2008 and beyond. Please read Note 6 Risk Management Activities, Derivatives and Financial Instruments Accounting for Derivative Instruments and Hedging Activities Cash Flow Hedges for a discussion of our decision to no longer designate derivative transactions as cash flow hedges beginning with the second quarter 2007; and
- Results were favorably impacted in 2006 by $12 million due to an opportunistic sale of emissions credits that were not required for near-term operations of our facilities. Similar sales of $10 million occurred in 2007.

Depreciation expense increased from $24 million for the year ended December 31, 2006 to $45 million for the year ended December 31, 2007. This was primarily due to the new Northeast plants.

Other. Dynegy s other operating loss for the year ended December 31, 2007 was $184 million, compared to an operating loss of $156 million for the year ended December 31, 2006. DHI s other operating loss for the year ended December 31, 2007 was $165 million, compared to an operating loss of $153 million for the year ended December 31, 2006. Operating losses in both periods were comprised primarily of general and administrative expenses offset by results from our former customer risk management business. Results for 2007 include a $31 million pre-tax gain associated with the acquisition of Kendall. Prior to the acquisition, Kendall held a power tolling contract with our CRM business. Upon completion of the Merger, this contract became an intercompany agreement, and was effectively eliminated on a consolidated basis, resulting in the $31 million gain. Please read Note 3 Business Combinations and Acquisitions LS Power Business Combination for further discussion. Results for 2007 and 2006 reflect legal and settlement charges of approximately $15 million and $53 million, respectively, resulting from additional activities during the period that negatively affected management s assessment of probable and estimable losses associated with the applicable proceedings. The 2007 legal and settlement charges were partially offset by a $4 million gain on the sale of NYMEX securities. The 2006 legal and settlement charges were partially offset by mark-to-market income on our legacy coal, natural gas, emissions, and power positions.

Dynegy s consolidated general and administrative expenses increased to $203 million for the year ended December 31, 2007 from $196 million for the year ended December 31, 2006. General and administrative expenses for the year ended December 31, 2007 included legal and settlement charges of $36 million, compared with legal and settlement charges of $53 million in the same period of 2006. For the years ended December 31, 2007 and 2006, $15 million and $53 million, respectively, of this general and administrative expense was related to legal and settlement charges reported in our CRM business, as discussed above. Additionally, general and administrative expenses for 2007 included a charge of approximately $6 million in connection with the accelerated vesting of restricted stock and stock option awards previously granted to employees, which vested in full upon closing of the Merger. The remaining increase from 2006 to 2007 was primarily a result of higher salary and employee benefit costs due to the Merger.

DHI s consolidated general and administrative expenses decreased to $184 million for the year ended December 31, 2007 from $193 million for the year ended December 31, 2006. General and administrative expenses for the year ended December 31, 2007 included legal and settlement charges of $17 million, compared with legal and settlement charges of $53 million in the same period of 2006. For the years ended December 31, 2007 and 2006, $15 million and $53 million, respectively, of this general and administrative expense was related to legal , respectively charges reported in our CRM segment, as discussed above. The decrease in legal and settlement charges from 2006 to 2007 was partially offset by a charge of approximately $6 million in 2007 related to the accelerated vesting of restricted stock and stock option awards previously granted to employees, which vested in full upon closing of the Merger. Additionally, salary and employee benefit costs were higher in 2007 as a result of the Merger.

Earnings (Losses) from Unconsolidated Investments

Dynegy s losses from unconsolidated investments were $3 million for the year ended December 31, 2007 compared to losses of $1 million for the year ended December 31, 2006. Earnings in 2007 included $10 million from the GEN-WE investment in the Sandy Creek largely due to its share of the gain on SCEA s sale of a 25 percent undivided interest in the Sandy Creek Project. Please read Note 12 Variable Interest Entities Sandy Creek for further information. This income was partially offset by losses related to Dynegy s interest in DLS Power Holdings. Earnings in 2006 related to the GEN-WE investment in Black Mountain.

DHI s earnings from unconsolidated investments were $6 million for the year ended December 31, 2007, compared with losses of $1 million the year ended December 31, 2006. Earnings in 2007 included $10 million from the GEN-WE investment in the Sandy Creek largely due to its share of the gain on SCEA s sale of a 25 percent undivided interest in the Sandy Creek Project. Please read Note 12 Variable Interest Entities Sandy Creek for further information. Earnings in 2006 related to the GEN-WE investment in Black Mountain.

Other Items, Net

Dynegy s other items, net totaled $49 million of income for the year ended December 31, 2007, compared to $54 million of income for the year ended December 31, 2006. The decrease was primarily associated with $7 million of minority interest expense related to the Plum Point facility as well as foreign currency losses in the year ended December 31, 2007. The minority interest expense was primarily due to the mark-to-market interest income recorded during the three months ended June 30, 2007 related to the interest rate swap agreements associated with the Plum Point Credit Agreement. Please read Interest Expense below for further discussion.

DHI s other items, net totaled $46 million of income for the year ended December 31, 2007, compared to $51 million of income for the year ended December 31, 2006. The decrease was primarily associated with $7 million of minority interest expense recorded in 2007 related to the Plum Point facility. The minority interest expense was primarily due to the mark-to-market interest income recorded during the three months ended June 30, 2007 related to the interest rate swap agreements associated with the Plum Point Credit Agreement. Please read Interest Expense below for further discussion.

Interest Expense

Dynegy s interest expense and debt conversion costs totaled $384 million for the year ended December 31, 2007, compared to $631 million for the year ended December 31, 2006. DHI s interest expense and debt conversion costs totaled $384 million for the year ended December 31, 2007, compared to $579 million for the year ended December 31, 2006.

The decrease was primarily attributable to debt conversion costs and acceleration of financing costs resulting from our liability management program executed in the second quarter of 2006 as well as a $36 million charge associated with the Sithe Subordinated Debt exchange. Included in interest expense for the year ended December 31, 2007 was approximately $24 million of mark-to-market income from interest rate swap agreements associated with the Plum Point Credit Agreement Facility. Effective July 1, 2007, these agreements were designated as cash flow hedges. Also included in interest expense for the year ended December 31, 2007 was approximately $12 million of income from non-designated interest rate swap agreements that, prior to being terminated, were associated with the portion of the debt repaid in late May 2007. The mark-to-market income included in interest expense for 2007 was offset by net losses of approximately $7 million in connection with the repayment of a portion of the project indebtedness assumed in connection with the Merger. These items were offset by higher interest expense incurred in 2007 due to higher 2007 debt balances resulting from the Merger.

Income Tax (Expense) Benefit

Dynegy reported an income tax expense from continuing operations of $151 million for the year ended December 31, 2007, compared to an income tax benefit from continuing operations of $152 million for the year ended December 31, 2006. The 2007 effective tax rate was 57 percent, compared to 32 percent in 2006. The income tax expense in 2007 included a $4 million benefit resulting from the change in New York state tax law and a $3 million expense resulting from a net increase in tax reserves. Additionally, Dynegy realized a higher state income tax expense resulting from adjusting Dynegy s temporary differences to a higher overall effective state tax rate. The higher effective state tax rate was driven by changes in levels of business activity in states in which we do business and the higher state tax rates in the states in which the Contributed Entities are located. Excluding the impact of changes in levels of business activity and changes in company structure, the 2007 calculation would result in an effective tax rate of 36 percent.

DHI reported an income tax expense from continuing operations of $116 million for the year ended December 31, 2007, compared to an income tax benefit from continuing operations of $125 million for the year ended December 31, 2006. The 2007 effective tax rate was 40 percent, compared to 30 percent in 2006. The income tax expense in 2007 included a $14 million benefit resulting from the change in New York state tax law and a $16 million benefit resulting from the release of tax reserves. Additionally, DHI realized a higher state income tax expense resulting from adjusting DHI s temporary differences to a higher overall effective state tax rate. The higher effective state tax rate was driven by changes in levels of business activity in states in which we do business and the higher state tax rates in the states in which the Contributed Entities are located. Excluding the impact of changes in levels of business activity and changes in company structure, the 2007 calculation would result in an effective tax rate of 31 percent.

Discontinued Operations

Income From Discontinued Operations Before Taxes. Discontinued operations include the Calcasieu and CoGen Lyondell power generation facilities in our GEN-WE segment, DMSLP in our former NGL segment and our U.K. CRM business.

During the year ended December 31, 2007, Dynegy s pre-tax income from discontinued operations was $239 million ($148 million after-tax). Dynegy s GEN-WE segment included $225 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities, consisting primarily of a pre-tax gain of $224 million associated with the completion of our sale of the CoGen Lyondell power generation facility. Dynegy s U.K. CRM included income of $15 million, primarily related to a favorable settlement of a legacy receivable.

During the year ended December 31, 2006, Dynegy s pre-tax loss from discontinued operations was $23 million ($13 million after-tax). Dynegy s GEN-WE segment included losses of $53 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities. The loss includes a $36 million impairment associated with the Calcasieu power generation facility. Dynegy s U.K. CRM included earnings of $23 million for the year ended December 31, 2006, primarily related to a favorable settlement of a legacy receivable. Dynegy also recorded pre-tax income of $6 million attributable to NGL.

During the year ended December 31, 2007, DHI s pre-tax income from discontinued operations was $240 million ($148 million after-tax). DHI s GEN-WE segment included $225 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities, consisting primarily of a pre-tax gain of $224 million associated with the completion of our sale of the CoGen Lyondell power generation facility. DHI s U.K. CRM included income of $15 million, primarily related to a favorable settlement of a legacy receivable.

During the year ended December 31, 2006, DHI s pre-tax loss from discontinued operations was $24 million ($12 million after-tax). DHI s GEN-WE segment included losses of $53 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities. The loss includes a $36 million impairment associated with the Calcasieu power generation facility. DHI s U.K. CRM included earnings of $23 million for the year ended December 31, 2006, primarily related to a favorable settlement of a legacy receivable. DHI also recorded pre-tax income of $6 million attributable to NGL.

Income Tax (Expense) Benefit From Discontinued Operations. Dynegy recorded an income tax expense from discontinued operations of $91 million during the year ended December 31, 2007, compared to an income tax benefit from discontinued operations of $10 million during the year ended December 31, 2006. The income tax expense in 2007 included a $9 million benefit from a net release of tax reserves. The effective tax rate was impacted by the

$47 million of goodwill allocated to the CoGen Lyondell power generation facility upon its sale. As there was no tax basis in the goodwill, there were no tax benefits associated with the allocated goodwill.

Table of Contents

DHI recorded an income tax expense from discontinued operations of $92 million during the year ended December 31, 2007, compared to an income tax benefit from discontinued operations of $12 million during the year ended December 31, 2006. The income tax expense in 2007 included an $8 million benefit from a net release of tax reserves. The effective tax rate for 2007 was impacted by the $47 million of goodwill allocated to the CoGen Lyondell power generation facility upon its sale. As there was no tax basis in the goodwill, there were no tax benefits associated with the allocated goodwill.

Cumulative Effect of Change in Accounting Principles

On January 1, 2006, we adopted SFAS No. 123(R), Share-Based Payment (SFAS No. 123(R)). In connection with its adoption, Dynegy realized a cumulative effect loss of approximately $1 million, net of tax expense of zero. Please read Note 2 Summary of Significant Accounting Policies Employee Stock Options for further information.

Outlook

Our fleet includes a diverse mixture of assets with various fuel, dispatch and merit order characteristics within each of our three regions. In commercializing our assets, we seek to achieve a balance between protecting cash flow in the near/intermediate term, while maintaining the ability to capture value longer term as markets tighten. We expect that a majority of our sales will be achieved by selling energy and capacity through a combination of spot market sales and near-term contracts over a rolling 12 36 month time frame in time periods that we describe as Current, Current +1, and Current +2. At any given point in time, we will seek to balance predictability of earnings and cash flow with achieving the highest level of earnings and cash flow possible over the Current, Current +1 and Current +2 periods. In these periods we understand that short-term market volatility can negatively impact our profitability, and we will seek to reduce those negative impacts through the disciplined use of near- and intermediate-term forward sales. As a result, our fleet-wide forward sales profile is fluid and subject to change. We expect to make fewer forward sales beyond the Current+2 period in order to realize the anticipated benefit of improved market prices over time as the supply and demand balance tightens.

We expect that our future financial results will continue to reflect sensitivity to fuel and commodity prices, market structure and prices for electric energy, ancillary services, capacity and emissions allowances, transportation and transmission logistics, weather conditions and IMA. Our commercial team actively manages commodity price risk associated with our unsold power production by trading in the forward markets that are correlated with our assets. We also participate in various regional auctions and bilateral opportunities. Our regional commercial strategies are particularly driven by the types of units that we have within a given region and the operating characteristics of those units.

The latter part of 2008 was characterized by turmoil in the financial markets. Several large financial institutions have failed, and stock prices across industries, including ours, have fallen sharply. These market conditions have resulted in a decreased willingness on the part of lenders to enter into new loans. We believe there has been a reduction in the number of counterparties participating in, and the volume of transactions available for execution in, the bilateral energy markets, making it more difficult to optimize the value of our assets. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources for further discussion of the impact of recent market developments on our business.

To the extent that we choose not to enter into forward sales, the gross margin from our assets is a function of price movements in the coal, natural gas, fuel oil, electric energy and capacity markets.

Table of Contents

The following summarizes unique business issues impacting our individual regions outlook.

GEN-MW. Our Consent Decree requires substantial emission reductions from our Illinois coal-fired power generating plants and the completion of several supplemental environmental projects in the Midwest. We have achieved all emission reductions scheduled to date under the Consent Decree and are installing additional emission control equipment to meet future Consent Decree emission limits. We anticipate our costs associated with the Consent Decree projects, which we expect to incur through 2012, to be approximately $960 million, which includes approximately $290 million spent to date. This estimate required a number of assumptions about uncertainties beyond our control. For instance, we have assumed, for purposes of this estimate, that labor and material costs will increase at four percent per year over the remaining project term. The following are the estimated capital expenditures required to comply with the Consent Decree:

2009	2010	2011	2012
	(in millions)		
$ 245	$ 215	$ 165	$ 45

If the costs of these capital expenditures become great enough to render the operation of the affected facility or facilities uneconomical, we could, at our option, cease to operate the facility or facilities and forego these capital expenditures without incurring any further obligations under the Consent Decree. Please read Note 19 Commitments and Contingencies Other Commitments and Contingencies Consent Decree for further discussion.

Our Midwest coal requirements are 100 percent contracted through 2010. For 2009, the prices associated with these contracts are fixed. Approximately 25 percent of our 2010 coal requirements are currently unpriced, and will be priced in September 2009. The new prices determined in September will become effective January 1, 2010. We expect that any price changes will be consistent with the historical price trend over the past several years.

PJM recently implemented a forward capacity auction, the Reliability Pricing Model. The auction has resulted in an increase in the value of capacity in not only PJM, but in the neighboring MISO as well, compared to periods before the auction was in place. We participated in the auction process, resulting in sales of capacity for the following planning years:

Planning Year	Net Capacity (in MWs)	Weighted Average Capacity Price ($ per MW-day)
2008-2009	885	112
2009-2010	2,240	123(1)
2010-2011	2,057	174
2011-2012	2,061	110

(1) Calculated as the weighted average of 1,723 MWs at $102 per MW-day for RTO and 517 MWs at $191 per MW-day for MAAC+APS.

GEN-WE. In 2009, we expect our Morro Bay facility to benefit from a new tolling arrangement with a utility in California. Approximately two thirds of power plant capacity in the West is contracted for under a variety of tolling agreements with load-serving entities and Reliability Must Run agreements with the California ISO. A significant portion of the remaining capacity is sold as a Resource Adequacy product in the California market, and much of the production associated with the plants without tolls or Reliability Must Run agreements has been hedged. As a result, the earnings of our West region tend to be less volatile than in our other regions.

GEN-NE. We continue to maintain sufficient coal and fuel oil inventories to effectively manage our operations. We have contracted 100 percent and approximately 35 percent of our expected coal supply for 2009 and 2010, respectively, for our Danskammer power generation facility primarily from South American suppliers at delivered prices that are competitively priced compared to domestic suppliers. Multiple sourcing options are under evaluation for the remainder of our 2010 supply needs. Markets for coal, like other world energy commodity markets, experienced significant volatility during 2008, and this volatility is likely to continue through 2009-2010. However, coal prices in both the international and domestic markets have decreased significantly from their historic highs reached in the middle of 2008. We are exploring various alternative contractual commitments and financial options, as well as facility modifications, to ensure stable fuel supplies and to further mitigate cost and supply risks for near and long-term coal supplies.

The volatility in fuel oil commodity pricing should provide us opportunities to capture additive short-term market value through strategic purchases of fuel oil in the spot market. Lower commodity prices of fuel oil have further positioned our Roseton facility, which is capable of burning natural gas and fuel oil, to capture these market opportunities.

Table of Contents

In New England, the ISO-NE is in the process of restructuring its capacity market and will be transitioning to a forward capacity market in 2010. During the transition from the pre-existing capacity markets in ISO-NE to the forward capacity market, all listed ICAP resources will receive monthly capacity payments, adjusted for each power year. The transitional payments for capacity commenced in December 2006, with a price of $3.05/KW-month, and gradually rise to $4.10/KW-month through September 1, 2010, when the forward capacity market will be fully effective. Capacity auctions for the 2010/2011 and 2011/2012 were held in 2008 and resulted in capacity payments of $4.50 KW/month and $4.50 KW/month respectively for our assets in New England.

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 natural 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 seven critical accounting policies that require a significant amount of estimation and judgment and are considered important to the portrayal of our financial position and results of operations:

- Revenue Recognition and Valuation of Risk Management Assets and Liabilities;
- Valuation of Tangible and Intangible Assets;
- Accounting for Contingencies, Guarantees and Indemnifications;
- Accounting for Asset Retirement Obligations;
- Accounting for Variable Interest Entities;
- Accounting for Income Taxes; and
- Valuation of Pension and Other Post-Retirement Plans Assets and Liabilities.

Revenue Recognition and Valuation of Risk Management Assets and Liabilities

We earn revenue from our facilities in three primary ways: (i) sale of energy generated by our facilities; (ii) 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 (iii) sale of capacity. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative, as defined by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended, (SFAS No. 133). Please read Derivative Instruments Generation for further discussion of the accounting for these types of transactions.

Derivative Instruments Generation. We enter into commodity contracts that meet the definition of a derivative under SFAS No. 133. These contracts are often entered into to mitigate or eliminate market and financial risks associated with our generation business. These contracts include power sales contracts, fuel purchase contracts, heat rate call options, and other instruments used to mitigate variability in earnings due to fluctuations in market prices. SFAS No. 133 provides for three different ways to account for these types of contracts: (i) as an accrual contract, if the criteria for the normal purchase normal sale exception are met and documented; (ii) as a cash flow or fair value hedge, if the criteria are met and documented; or (iii) as a mark-to-market contract with changes in fair value recognized in current period earnings. All derivative commodity contracts that do not qualify for the normal purchase normal sale exception are recorded at fair value in risk management assets and liabilities on the consolidated balance sheets. If the derivative commodity contract has been designated as a cash flow hedge, the changes in fair value are recognized in earnings concurrent with the hedged item. Changes in the fair value of derivative commodity contracts that are not designated as cash flow hedges are recorded currently in earnings. Because derivative contracts can be accounted for in three different ways, and as the normal purchase normal sale exception and cash flow and fair value hedge accounting are elective, the accounting treatment used by another party for a similar transaction could be different from the accounting treatment we use. To the extent a party elects to apply cash flow hedge accounting for qualifying transactions, there is generally less volatility in the income statement as the effective portion of the changes in the fair values of the derivative instruments is recognized through equity.

We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement and we did not elect to adopt the netting provisions allowed under FSP FIN 39-1, Amendment of FASB Interpretation No. 39 , which allows an entity to offset the fair value amounts recognized for cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. As a result, our consolidated balance sheets present derivative assets and liabilities, as well as cash collateral paid or received, on a gross basis.

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

Derivative Instruments Financing Activities. We are exposed to changes in interest rate risk through our variable and fixed rate debt. In order to manage our interest rate risk, we enter into interest rate swap agreements that meet the definition of a derivative under SFAS No. 133. SFAS No. 133 requires us to mark-to-market all derivative instruments on the balance sheet. If the derivative is designated as a cash flow hedge, the effective portions of the changes in the fair value of the derivative are recorded in OCI and the realized gains and losses related to these derivatives are recognized in earnings in the same period as the settlement of the underlying hedged transaction. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized currently in earnings. If the derivative is not designated as a hedge, the change in value is recognized currently in earnings. To the extent a party elects to apply hedge accounting for qualifying transactions, there is generally less volatility in the income statement as a portion of the changes in the fair value of the derivative instruments is recognized through equity.

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

Fair Value Measurements. Fair value, as defined in SFAS No. 157, is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under SFAS No. 157, we utilize a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of our assets and liabilities measured and reported at fair value. Where appropriate, valuation adjustments are made to account for various factors, including the impact of our credit risk, our counterparties credit risk and bid-ask spreads. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as listed equities.

Level 2 Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over the counter forwards, options and repurchase agreements.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to our needs. At each balance sheet date, we perform an analysis of all instruments subject to SFAS No. 157 and include in Level 3 all of those whose fair value is based on significant unobservable inputs.

The determination of the fair values incorporates various factors required under SFAS No. 157. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities. Valuation adjustments are generally based on capital market implied ratings evidence when assessing the credit standing of our counterparties and when applicable, adjusted based on management s estimates of assumptions market participants would use in determining fair value.

Assets and liabilities from risk management activities may include exchange-traded derivative contracts and OTC derivative contracts. Some exchange-traded derivatives are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets. In such cases, these exchange-traded derivatives are classified within Level 2. OTC derivative trading instruments include swaps, forwards, options and complex structures that are valued at fair value. In certain instances, these instruments may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives trade in less active markets with a lower availability of pricing information. In addition, complex or structured transactions, such as heat-rate call options, can introduce the need for internally-developed model inputs that might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3. Other assets represent available-for-sale securities.

Valuation of Tangible and Intangible Assets

We evaluate long-lived assets, such as property, plant and equipment and investments, when events or changes in circumstances 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;
- 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.

Table of Contents

We assess the carrying value of our property, plant and equipment and intangible assets subject to amortization in accordance with SFAS No. 144. If an impairment is indicated, the amount of the impairment loss recognized would be determined by the amount the book value exceeds the estimated fair value of the assets. The estimated fair value may include estimates based upon discounted cash-flow projections, recent comparable market transactions or quoted prices to determine if an impairment loss is required. For assets identified as held for sale, the book value is compared to the estimated sales price less costs to sell. There is a significant amount of judgment involved in cash-flow estimates, including assumptions regarding market convergence, discount rates and capacity. The assumptions used by another party could differ significantly from our assumptions. Please read Note 5 Impairment Charges for discussion of impairment charges we recognized in 2008 and 2006.

We follow the guidance of APB 18, The Equity Method of Accounting for Investments in Common Stock (APB 18), SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities (SFAS No. 115), and EITF Issue 02-14, Whether an Investor Should Apply the Equity Method of Accounting to Investments Other Than Common Stock (EITF 02-14), 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 estimated 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. Please read Note 12 Variable Interest Entities DLS Power Holdings and DLS Power Development for further discussion of our accounting for the impairment of our investment in DLS Power Holdings.

We assess the carrying value of our goodwill in accordance with SFAS No. 142. Our goodwill test is performed annually on November 1 and when circumstances warrant. We generally determine the fair value of our reporting units using the income approach and utilize market information such as recent sales transactions for comparable assets within the regions in which we operate to corroborate the fair values derived from the income approach. The discounted cash flows for each reporting unit are based on discrete financial forecasts developed by management for planning purposes. Cash flows beyond the discrete forecasts are estimated using a terminal value calculation, which incorporates historical and forecasted financial trends and considers long-term earnings growth rates based on growth rates observed in the power sector. There is a significant amount of judgment in the determination of the fair value of our reporting units, including assumptions around market convergence, discount rates, capacity and growth rates. We evaluated the sensitivity of our more significant assumptions, including our discount rates and terminal value assumptions. Based on the results of this analysis, we concluded that a change in these assumptions within a range that we consider reasonable would not cause the fair value of any of our reporting units to be less than their respective carrying values.

As of November 1, 2008, the date at which we performed our annual impairment test, Dynegy s market capitalization was below its book value. We have qualitatively reconciled the aggregate fair value of our reporting units to our market capitalization by considering several factors, including

(i) Our market capitalization has been below book value for a relatively short period of time, which coincides with unprecedented volatility in the broader financial markets, as well as significant volatility in our industry.

Our stock price and our overall industry sector market capitalization were negatively impacted in late summer/early fall 2008 as a result of two of our peers experiencing significant liquidity constraints. While we believe that we have been, and continue to be, in a solid liquidity position, we believe that our stock price was negatively impacted as a result of the perception of liquidity constraints within our industry sector. Soon after our peers experienced their liquidity issues, the broader financial market experienced a liquidity crisis. While we do not have any significant debt maturities until 2011, we believe the liquidity issues suffered by our peers when combined with the broader financial market liquidity crisis further deteriorated our market capitalization.

(ii) Our share price was negatively impacted in the third and fourth quarters of 2008 by the sale of shares by hedge funds and lack of buying by institutional investors.

Given the liquidity issues in the broader financial markets and the unique issues faced by several of our peers, we noted that our share price was negatively impacted in the third and fourth quarters of 2008 by the sale of approximately 20 million shares (4 percent of our Class A shares) by hedge funds. Additionally, lack of demand on the part of institutional investors further depressed our stock price. Our stock price at November 1, 2008, the date of our annual goodwill impairment test, was $3.64 per share while our shareholders equity was approximately $5.60 per share. Prior to the consideration of a control premium, the market capitalization at November 1, 2008, if used as a basis to determine fair value, would imply that our assumptions regarding discount rates in our November 1, 2008 valuation were significantly understated and/or our assumptions regarding terminal value growth rates were significantly overstated. For example, one scenario would require adjusting discount rates upward by approximately 300 to 500 basis points, depending on the reporting unit, as well as reducing the terminal value growth rates by approximately three to six times, also depending on the reporting unit. However, we believe that our assumptions and the resulting valuations are appropriate and corroborated by other market information and that using the implied assumptions inherent in our market capitalization is not appropriate at this time given the unusual circumstances driving the value of our stock.

(iii) Lastly, our share price does not reflect a control premium.

Due to further declines in our market capitalization through December 31, 2008, we determined if any assumptions utilized in the November 1, 2008 analysis required updating. We evaluated key assumptions including forward natural gas and power pricing, power demand growth, and cost of capital. While some of the assumptions had changed subsequent to the November 1, 2008 analysis, we determined that the impact of updating those assumptions would not have caused the fair value of the individual reporting units to be below their respective carrying values at December 31, 2008.

Our valuation has appropriately considered the impact of the current economic environment. However, because of the nature of our business and the underlying fundamentals of the power markets, industry market data continues to support long-term power demand growth and the need for additional electric generation capacity dampening the impact of a short-term recession in our marketplace. After giving consideration to these factors; we concluded that our market capitalization was not indicative of the fair value of our aggregate reporting units and we did not fail the first step of the goodwill impairment test for any of our reporting units. Our stock price is generally influenced by movements in near-term forward natural gas and power prices. Subsequent to December 31, 2008, forward commodity prices, particularly in the near term, have continued to decline along with our stock price. We continue to monitor forward market commodity prices and other significant assumptions used in our valuation. If our stock price continues to be depressed and we believe this is indicative of the downturn in the economic environment continuing for a long period of time causing a significant decline in long-term demand for electricity and/or depressed commodity prices over the long term, we will be required to update our discounted cash flow analysis and potentially required to record a goodwill impairment in the future. Furthermore, if our market capitalization continues to be below our book value for a sustained period of time, we will need to consider updating our assessment and could be required to record a goodwill impairment in the future.

Accounting for Contingencies, Guarantees and Indemnifications

We are involved in numerous lawsuits, claims, proceedings, and tax-related audits in the normal course of our operations. In accordance with SFAS No. 5, Accounting for Contingencies (SFAS No. 5), 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 our consolidated balance sheets as required by SFAS No. 5. 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 judgments 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.

Liabilities are recorded when an 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.

Table of Contents

We follow the guidance of FIN No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (FIN No. 45), for disclosure 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 and 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.
Please read Note 19 Commitments and Contingencies for further discussion of our commitments and contingencies.

Accounting for Asset Retirement Obligations

Under the provisions of SFAS No. 143, Asset Retirement Obligations (SFAS No. 143), and FIN No. 47 Accounting for Conditional Asset Retirements (FIN No. 47), we are required to record the present value of the future obligations to retire tangible, long-lived assets on our consolidated balance sheets as liabilities 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 for the amount or timing of the cash flows change, the change may have a material impact on our financial condition and results of operations.
Please read Note 2 Summary of Significant Accounting Policies Asset Retirement Obligations for further discussion of our accounting for AROs.

Accounting for Variable Interest Entities

We follow the guidance in FIN 46(R), Consolidation of Variable Interest Entities , which requires that we evaluate certain entities to determine which party is considered the primary beneficiary of the entity and thus required to consolidate it in its financial statements. We are or have been an investor in several variable interest entities to which LS Associates, a related party, is also an investor. There is a significant amount of judgment involved in determining the primary beneficiary of an entity from a related party group. We have concluded that we are not and were not the primary beneficiary of these entities because a) we believe that LS Power is more closely associated with the entities, b) they own approximately 40 percent of Dynegy s outstanding common stock and c) they have three seats on Dynegy s Board of Directors. If different judgment was applied, we could be considered the primary beneficiary of some or all of these entities, which would significantly impact our financial condition and results of operations. Please read Note 12 Variable Interest Entities for further discussion of our accounting for our variable interest entities.
We are also an investor, with independent third parties, in PPEA. PPEA is a variable interest entity, and there is a significant amount of judgment involved in the analysis used to determine the primary beneficiary. The analysis includes assumptions about forecasted cash flows, construction costs, and plant performance. We have concluded that we are the primary beneficiary of PPEA and therefore consolidate the entity in our consolidated financial statements. If different judgment was applied, we may not be considered the primary beneficiary for this entity, which would significantly impact our financial condition, results of operations and cash flows.
Please read Note 12 Variable Interest Entities for further discussion of our accounting for our variable interest entities.

Accounting for Income Taxes

We follow the guidance in SFAS No. 109, Accounting for Income Taxes (SFAS No. 109), 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 tax and accounting 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.

Because we operate and sell power in many different states, our effective annual state income tax rate will vary from period to period because of changes in our sales profile by state, as well as jurisdictional and legislative changes by state. As a result, changes in our estimated effective annual state income tax rate can have a significant impact on our measurement of temporary differences. We project the rates at which state tax temporary differences will reverse based upon estimates of revenues and operations in the respective jurisdictions in which we conduct business. A change of 1 percent in the estimated effective annual state income tax rate at December 31, 2008, could impact deferred tax expense by approximately $41 million for Dynegy and $31 million for DHI. State statutory tax rates in the states in which we do business range from 1.0 percent to 9.5 percent.

In February, 2009, the State of California enacted several changes to its corporate income tax laws. As a result of these changes, we anticipate recording an increase to our deferred tax liability. The impact of these changes will be incorporated in our first quarter 2009 tax provision.

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 percent) 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, 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 deferred tax 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 changes. Any change in the valuation allowance would impact our income tax (expense) benefit and net income (loss) in the period in which such a determination is made.

Effective January 1, 2007, we adopted FIN No. 48 which requires that we determine if it is more likely than not that a tax position we have taken will be sustained upon examination. If we determine that it is more likely than not that the position will be sustained, we recognize the largest amount of the benefit that is greater than 50 percent likely of being realized upon settlement. There is a significant amount of judgment involved in assessing the likelihood that a tax position will be sustained upon examination and in determining the amount of the benefit that will ultimately be realized. If different judgments were applied, it is likely that reserves would be recorded for different amounts. Actual amounts could vary materially from these reserves.

Please read Note 17 Income Taxes for further discussion of our accounting for income taxes, adoption of FIN No. 48 and change in our valuation allowance.

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, changes in the value of plan assets and changes in the level of benefits provided.

We used a yield curve approach for determining the discount rate as of December 31, 2008. The discount rate is subject to change each year, consistent with changes in applicable high-quality, long-term corporate bond indices. Projected benefit payments for the plans were matched against the discount rates in the Citigroup Pension Discount Curve to produce a weighted-average equivalent discount rate. Long-term interest rates decreased during 2008. Accordingly, at December 31, 2008, we used a discount rate of 6.12 percent for pension plans and 5.93 percent for other retirement plans, a decrease of 34 and 55 basis points, respectively, from the 6.46 percent for pension plans rate and 6.48 percent for other retirement plans rate used as of December 31, 2007. This decrease in the discount rate increased the underfunded status of the plans by $14 million.

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, 2009 and 2008 was 8.25 percent.

Table of Contents

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, 2008	Impact on 2009 Expense
	(in millions)	
Increase in Discount Rate 50 basis points	$ (14)	$ (2)
Decrease in Discount Rate 50 basis points	15	2
Increase in Expected Long-term Rate of Return 50 basis points		(1)
Decrease in Expected Long-term Rate of Return 50 basis points		1

We expect to make $28 million in cash contributions related to our pension plans during 2009. In addition, we may be required to continue to make contributions to the pension plans beyond 2009. Although it is difficult to estimate these potential future cash requirements due to uncertain market conditions, we currently expect that we will contribute approximately $24 million in 2010 and $29 million in 2011.

Please read Note 21 Employee Compensation, Savings and Pension Plans for further discussion of our pension-related assets and liabilities.

RECENT ACCOUNTING PRONOUNCEMENTS

We adopted SFAS No. 157, Fair Value Measurements and SFAS No. 159, The Fair Value Option for Financial Assets and Liabilities on January 1, 2008. We adopted FIN No. 48, Accounting for Uncertainty in Income Taxes (FIN No. 48) on January 1, 2007. We adopted SFAS No. 123(R) and SFAS No. 154, Accounting Changes and Error Corrections A Replacement of APB Opinion No. 20 and SFAS No. 3 , on January 1, 2006 and SFAS No. 158 on December 31, 2006. We adopted EITF Issue 05-6, Determining the Amortization Period for Leasehold Improvements , and FSP FIN No. 45-3, Application of FASB Interpretation No. 45 to Minimum Revenue Guarantees Granted to a Business or Its Owners , on January 1, 2006. Please read Note 2 Summary of Significant Accounting Policies Accounting Policies Not Yet Adopted for further discussion for accounting policies not yet adopted.

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, 2008 (in millions)
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at January 1, 2008	