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DYNEGY

2008
Annual Report

FINANCIAL HIGHLIGHTS

($ in millions, except per share amounts)	Year Ended December 31, 2008	2007	2006
FINANCIAL DATA			
Operating revenues	**$3,549**	$3,103	$1,770
Power Generation - Midwest operating income	**684**	495	208
Power Generation - West operating income (loss)	**90**	130	(2)
Power Generation - Northeast operating income	**67**	164	55
Operating income (loss)	**709**	605	105
Income from discontinued operations, net of tax	**3**	148	(13)
Net income (loss)	**174**	264	(333)
Net income (loss) applicable to common shareholders	**174**	264	(342)
Capital expenditures, investments and acquisitions	**640**	504	163
Cash flow provided by (used in) operations	**319**	341	(194)
Total long-term debt and obligations	**6,823**	6,741	4,034
COMMON SHARE DATA			
Earnings (loss) per diluted common share	**$ 0.20**	$ 0.35	$ (0.75)
Annual cash dividend per common share*	**-**	-	-
Market price at year-end	**2.00**	7.14	7.24
Average common shares outstanding (in millions)			
Diluted	**842**	754	509
Basic	**840**	752	459
OPERATING STATISTICS			
Power Generation - Midwest			
Electric power generated (net million megawatt hours)	**25**	25	22
Power Generation - West			
Electric power generated (net million megawatt hours)	**11**	11	1
Power Generation - Northeast			
Electric power generated (net million megawatt hours)	**8**	9	4

* Dividend suspended beginning in the third quarter 2002.

This annual report contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward-looking statements." These statements represent our 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, and they include words such as "anticipate," "estimate," "project," "forecast," "plan," "may," "will," "should," "expect" and other words of similar meaning. For information concerning our forward-looking statements and important factors that could cause our actual results to differ materially from those in such statements, see page 21 of the Form 10-K.

Guiding Principles

What we do:

- Produce and sell electric energy, capacity and ancillary services to key U.S. markets.

What we value:

- Our colleagues and teamwork.
- Honesty and integrity.
- Clear, candid and open communications.
- Diversity and inclusiveness in culture, experience and ideas.
- Commitment, discipline and focus.
- Individual responsibility and accountability.

How we operate:

- Do the right things with an expectation that the right things will happen.
- Operate safely, efficiently and consistent with our legal, ethical and environmental obligations.
- Trust and respect our fellow employees.
- Engage and develop our employees.
- Do things once and do them right.
- Recognize and reward performance.
- Work cooperatively and collaboratively.

We will be successful when:

- Our investors demonstrate confidence in our business strategy.
- Our employees live these Guiding Principles in their every action.
- Our communities recognize Dynegy as a valued corporate citizen.

To Our Investors:

If 2008 was a difficult year for U.S. business as a whole, consider that a unique set of challenges was presented to the power generation sector. During the course of the year, the price of the fuels used to generate electricity rose sharply, then precipitously declined. In some parts of the country, flooding and other weather-related issues impacted sales volumes.

Across America and around the world, some companies were faced with urgent needs for capital and credit, which was an extremely difficult proposition given the meltdown of financial markets. The companies that managed through these issues were those that went into the financial crisis with the right mix of business dynamics that served to insulate their balance sheets from external factors. We were one of these companies, thanks to the proactive work we have done over the past several years.

Throughout the year, Dynegy never wavered from its focus on operating our power plants and serving our markets and customers – nor did we depart from a set of core beliefs that has become a mainstay for our company:

- We manage our business as a public operating company to create long-term value;
- We work on behalf of all of our investors – including our common stockholders, fixed-income investors and our bank group;
- We manage with a belief that consolidation is coming for the power sector;
- We manage toward preserving options;
- We shed certain risks and actively manage retained risks; and
- We integrate our asset- and capital-based strategies to maximize results.

These core beliefs guided our asset- and capital-based strategies during the course of the year. Nevertheless, Dynegy experienced a number of challenges during 2008. In particular, we faced difficulties as we worked to adjust our commercial practices to changing market conditions. As I will discuss in more detail, we have developed what we believe will be a better commercial approach for 2009 and beyond – one that seeks to balance commercial risk and reward by reducing near-term merchant exposure with an increase in contracted positions. In addition to commercial issues, we also faced weather-related events and outages. However, in all cases, we modified our practices to meet the challenges at hand, we put our "lessons learned" to work, and today we are a stronger, more capable independent power producer.

In this letter, I will cover the significant events of the past year, prefacing the 2008 highlights discussion with a look at the asset- and capital-based sides of our business.

And lastly, I will share our value proposition for investors.

We sell wholesale power, capacity and ancillary services to utilities, cooperatives, municipalities and other energy companies in our key U.S. regions of the Midwest, the West and the Northeast.

Linking the left- and right-hand sides of our balance sheet

We often discuss the linking of the left and right sides of our balance sheet. For the left, or asset-based side, our commitments include operating and commercializing our assets well, harvesting value through non-core asset sales and either seeking out or potentially developing new assets.

The right side of the balance sheet reflects our capital-based strategies of enhancing liquidity, continuously trouble-shooting and streamlining our capital structure and allocating capital to the highest and best use.

Asset-based commitment

The best protection in an uncertain or cyclical market is a low-cost, well-operated group of assets producing a product that is needed. To that end, our power generation portfolio, with more than 18,000 megawatts of generation capacity, represents one of our key competitive advantages. This portfolio is diverse in terms of geography, fuel and dispatch, and is coupled with a commercial approach that varies by asset class and diversifies the marketplace risks inherent in our business.

From the standpoint of portfolio diversity, approximately 70 percent of our overall fleet's production capacity is natural gas-fired, which includes modern combined-cycle plants and peakers, and approximately 20 percent is derived from coal-fired baseload plants. These baseload plants currently provide reliability to our earnings, while our significant natural gas fleet represents future earnings potential given the expected expansion of heat rates as supply and demand tighten over time.

Here is a snapshot of our three business segments: the Midwest, West and Northeast:

	Megawatts	Plants	States	Gas	Coal	Oil	Region
Midwest	8,405	15	IL, MI, KY, AR, PA	62%	35%	3%	MISO, PJM, SERC
West	6,063	9	CA, AZ, GA, NV, TX	92%	5%	3%	CAISO, WECC, SERC, ERCOT
Northeast	3,809	5	NY, CT, ME	56%	20%	24%	NYISO, ISO-NE
Total	18,277	29		69%	22%	9%	

Chart includes the Plum Point and Sandy Creek projects under construction in Arkansas and Texas, respectively. Dynegy has entered an agreement to sell the Heard County facility in Georgia, which is expected to close in the second quarter of 2009. Fuel percentages are based on generating capacity by region and on a fleet-wide basis.

Dynegy's corporate structure supports our mission of being a low-cost provider. With anticipated general and administrative costs of approximately $175 million in 2009, we believe we have one of the leanest corporate cost structures in the sector. In addition, our business platform is scalable to support a larger power generation portfolio. As we demonstrated in 2007 with our acquisition of approximately 8,000 megawatts of operating assets, this gives us the ability to grow without a commensurate increase in expenses.

Capital-based strategies

We have developed a financial strategy that uses our balance sheet and liquidity as the ultimate hedge against changes in commodity prices, economic downturns and financial uncertainty. As of December 31, 2008, we had approximately $1.8 billion in liquidity, no significant debt maturities until 2011, an undrawn bank facility scheduled to remain in place until 2012 and a letter of credit facility that does not mature until 2013.

Our strategy requires us to actively monitor the credit markets to take advantage of financing opportunity windows instead of waiting until the debt matures. Consequently, the interest rate on our bank debt today stands at LIBOR plus 150 basis points. Considering the coupon on our other debt, this contributes to a weighted cost of debt of less than 8 percent, which is a much better rate than we could expect if we needed to refinance in today's markets.

Further, our capital structure has very little in the way of complex covenants or significant restrictions. This mitigates our exposure to market turmoil, while allowing us flexibility not only to invest in the business, but also to pursue strategies for reducing fixed-income debt, returning value to stockholders or growing through value-accretive combinations – all based on considerations of the highest and best use of capital. And while none of these options were pursued in 2008 because of the perceived greater need to preserve liquidity given the tumultuous market conditions, these options are and will continue to be re-evaluated as opportunities present themselves.

Dynegy's capital structure is closely aligned with our commercial strategy. We believe a strategy for commercializing our assets during the current year plus one or two years is the right approach for protecting near-term cash flows from intra-year volatility. Additionally, this leaves us open in the outer years to capture the longer-term benefits associated with tighter supply and demand, including anticipated increases in prices and volumes. Depending on local market factors, the length of our contracts may be longer for that part of our portfolio which includes combined-cycle plants and peakers.

At the end of 2008, our contracted percentage of expected generation was at 55 percent. Currently, our contracted percentage of expected generation stands at approximately 90 percent. Our commercial origination teams are continuing to reduce merchant exposure by entering into new contracted positions, thereby significantly increasing the contracted portion of our portfolio. This is expected to add predictability to our 2009 results, while mitigating risks outside of our control that hampered our performance in 2008 – and, importantly, leaving open the upside potential for future years.

2008 highlights

With our asset- and capital-based strategies as a backdrop, I will cover the company's 2008 results.

Operational performance – The company maintained its focus on safe, reliable and environmentally compliant operations throughout 2008. One important metric was the in-market availability of our baseload coal facilities of 90 percent. Our overall achievements in terms of plant reliability can be attributed to maintenance and operations effectiveness initiatives that are continually seeking new solutions for improving performance. As one example, an asset optimization project was recently completed at the 1,800-megawatt Baldwin Energy Complex where we participated with the U.S. Department of Energy to improve the facility's emissions profile and fuel efficiency.

In addition, we scrutinize expenses to tightly manage operating and capital costs with the goal of maximizing operating margins and cash flow. At the same time, we work to maintain a safe working environment. This focus on safety is top-of-mind for our operations groups, and resulted in one of the best safety years in the company's history in 2008.

Commercial performance – From a commercial perspective, 2008 was a challenging year for reasons both outside and within our control. A collapse in commodity prices and the exit of financial participants reduced overall market liquidity. Further, a widening of basis between liquid market and power delivery point prices, together with the commercializing of our assets in certain of these more liquid markets, impacted the company more than expected. We now anticipate and work to actively manage this risk by limiting forward sales from our Midwest assets into PJM or purchasing firm transmission rights and bilateral basis swaps.

Today's market conditions are extremely volatile, and we anticipate that this volatility will continue throughout 2009. In this environment, we are committed to doing a better job of commercializing our portfolio in a manner that protects cash flows and adds predictability to our earnings.

Dissolution of development joint venture – In January 2009, the company announced the dissolution of its development joint venture with LS Power and the re-evaluation of its participation in the Plum Point and Sandy Creek construction projects in Arkansas and Texas, respectively. As a result of the dissolution, in the future Dynegy will focus its development activities and investments around its existing operating portfolio. Because the development of new generation is increasingly marked by barriers to entry – including external credit and regulatory factors – we believe that focusing on our own portfolio where we control the option to develop and more tightly manage the related costs is a more sound strategy for us.

Sales of non-core assets – One of our ongoing strategies is the "pruning" of selected, non-core assets where sales prices exceed what those assets could reasonably be expected to bring in through the normal course of operations. In 2008, this effort produced the following results:

- Sale of the Rolling Hills peaking facility in Ohio for $368 million in cash;
- Sale of the residual value related to the Oyster Creek facility for $11.5 million in cash; and
- Sale of a partial interest in the Sandy Creek construction project, which effectively reduced the company's capital commitment for the project by approximately $50 million.

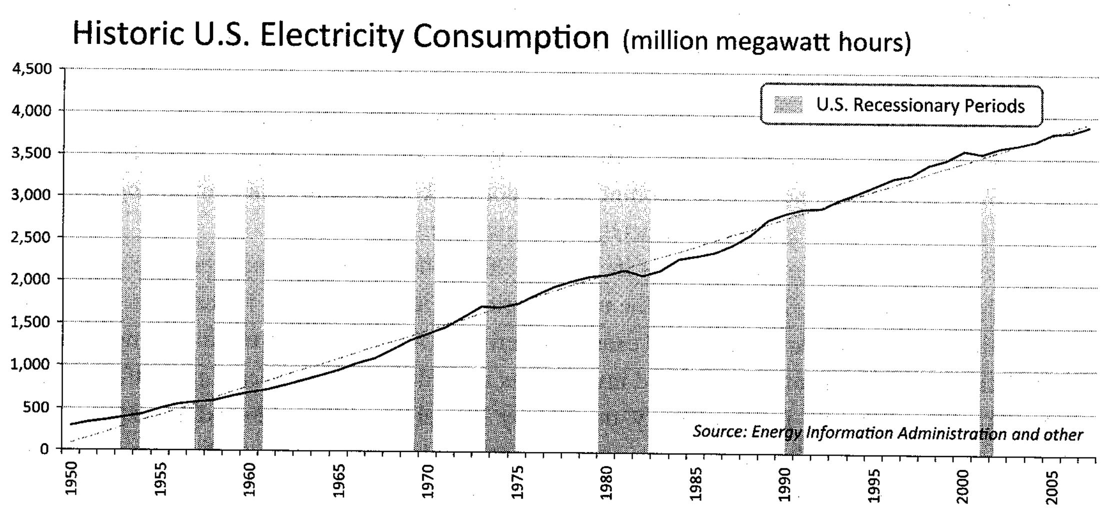
Fuel contracts – During 2008, the company strengthened its positions relative to coal contracts. Today, our rail transportation cost for Powder River Basin (PRB) coal, the low-sulfur fuel utilized by our Midwest baseload fleet, is 100 percent contracted through 2013 with no fuel escalators. In addition, our PRB coal supply is now contracted through 2010 at largely fixed pricing, with a meaningful portion contracted through 2012. Additionally, two units at our Danskammer facility in the Northeast rely on South American coal. We entered 2009 substantially contracted relative to Danskammer's supply and transportation needs.

Environmental progress – We are proud of our ability to serve our markets while continuing to make investments in cleaner operations. Dynegy is committed to $960 million of environmental projects involving eight of our Midwest coal units – approximately $275 million of which were completed in the 2005-2008 timeframe. During 2008, Midwest environmental accomplishments included the completion of baghouses at the Hennepin plant and, at year-end, 60 percent completion of a scrubber project at the Havana facility. We also began construction of a scrubber at the Baldwin Energy Complex. Both of those facilities will also have baghouses installed.

Our Midwest fleet has achieved a 90 percent reduction in sulfur dioxides and nitrogen oxides emissions over the past decade. All of our baghouse and scrubber projects are expected to be completed between now and 2012, and will further improve the Midwest fleet's standing as one of the cleanest operating coal fleets in the U.S., not only in relation to sulfur dioxide and nitrogen oxides, but for mercury and other emissions as well.

External factors that influence our business

We constantly monitor market factors that could impact our business. Two such factors are the U.S. economy and the introduction of federal greenhouse gas emission regulations. During previous recessionary periods, the U.S. has seen short-term drops in demand, and that may be the case in 2009. However, there is no reason to believe that demand growth will not continue over the longer term. As in past years, we believe this recovery will appear as a series of weather- and commodity price-driven peaks and valleys generally trending upward.



Relating to new energy regulations, we have been a proponent of comprehensive and pre-emptive federal legislation to deal with greenhouse gas emissions. In our view, a federal approach is a better alternative than the current patchwork of state and regional regulations that provide economic benefits for some parts of the country – and economic penalties for others – without tangible reductions in total U.S. carbon emissions.

We believe that successful U.S. energy policy will achieve balance among several pressing concerns:

- The environment and the global challenge of reducing greenhouse gas emissions;
- Electricity supplies that are both reliable and affordable – an important point at a time of economic weakness, when many low- and moderate-income consumers cannot afford higher electricity rates; and
- A reduced dependence on overseas energy sources.

Dynegy's risk factors related to climate change regulations can be found under Item 1A of our Annual Report on Form 10-K.

Our value proposition for investors

Dynegy's near-term challenge is to operate and commercialize well. Over the longer term, we believe that our diverse power generation fleet is the cornerstone of our value proposition. In an environment of rising barriers to entry that limit new generation capacity, we would expect an uplift in power pricing as well as higher valuations for existing operating assets. Further, the electricity sector remains fragmented with a large number of small-scale participants, which points to the benefits and eventuality of consolidation.

In this letter, I have outlined the factors that shaped our past-year performance, as well as the strategies and beliefs that have stood the test of time in the cyclical energy industry. These include maintaining a strong balance sheet with ample liquidity and limited near-term maturities, while operating power plants with a focus on the safe, reliable and economic production of megawatts. I also touched on the improvements we are making relative to our commercial approach – a focus on balancing risk and reward that should add near-term predictability to our results, while leaving us open to the longer-term economic benefits associated with power market recovery.

We believe these factors position Dynegy as a strong power generation franchise and investment vehicle for power sector investors seeking long-term value. I thank you for your interest and look forward to seeing many of you at our Annual Meeting of Stockholders on May 22 in Houston. For more information on our company, I encourage you to visit our web site at www.dynegy.com.

Bruce A. Williamson
Chairman, President and Chief Executive Officer
February 26, 2009

Board of Directors

James T. Bartlett, 41
Mr. Bartlett is President of LS Power Equity Advisors, LLC. Prior to joining LS Power in 2005, Mr. Bartlett served as a Managing Director in Credit Suisse First Boston's Energy Investment Banking Group where he focused on M&A and financing transactions in the power generation sector. Previously, Mr. Bartlett was an Associate at Kendall Capital Partners and an Analyst at Drexel Burnham Lambert. Mr. Bartlett began his service as a Dynegy Director in 2007.

David W. Biegler, 62
Mr. Biegler is the Chairman of Estrella Energy, L.P. He previously served as Chairman of Regency Gas Services, LLC, Vice Chairman, President and Chief Operating Officer of TXU Corp., and Chairman, President and Chief Executive Officer of ENSERCH Corp. Mr. Biegler serves as a Director of Trinity Industries, Inc., Austin Industries, Inc., Southwest Airlines Co., and Animal Health International, Inc. Mr. Biegler has served as a Dynegy Director since 2003. (2,4,5)

Thomas D. Clark, Jr., 68
Thomas D. Clark, Jr. is the President of Strategy Associates, a consulting firm specializing in strategy development, strategic planning assistance, corporate governance policy and corporate analysis. He previously served as Dean of the E.J. Ourso College of Business Administration at Louisiana State University, Ourso Distinguished Professor of Business, the Edward G. Schlieder Distinguished Chair of Information Science, and Director of the DECIDE Boardroom, an executive decision research and development facility. Mr. Clark also serves as a Director of Endeavour International. He has served as a Dynegy Director since 2003. (2,3,5)

Victor E. Grijalva, 70
Mr. Grijalva is the former Vice Chairman of Schlumberger Limited. Prior to serving in this role, he was Executive Vice President of Schlumberger's Oilfield Services division from 1994 to 1999 and Executive Vice President of the company's Wireline, Testing and Anadrill division from 1992 to 1994. Mr. Grijalva serves as a Director of Transocean, Inc. He has served as a Dynegy Director since 2006. (1,3,4,5)

Patricia A. Hammick, 62
Ms. Hammick is the former Senior Vice President, Strategy and Communications for Columbia Energy Group. She previously served as an adjunct Professor at George Washington University's Graduate School of Political Management and as Chief Operations Officer of the National Gas Supply Association. Ms. Hammick serves as a Director of Consol Energy, Inc. and SNC-Lavalin Group, Inc. A Dynegy Director since 2003, Ms. Hammick was elected Lead Director in 2004. (5)

Frank E. Hardenbergh, 65
Mr. Hardenbergh is Vice Chairman of LS Power Group. Mr. Hardenbergh joined LS Power in 1993. Prior to joining LS Power, Mr. Hardenbergh served as Senior Vice President, General Counsel and member of the Management Committee of the Commercial Union Capital Group. Before that, he was an Associate with Peabody & Arnold LLP. Mr. Hardenbergh began his service as a Dynegy Director in 2007.

George L. Mazanec, 72
Mr. Mazanec is the former Vice Chairman of PanEnergy Corp. He previously served as Advisor to the Chief Operating Officer of Duke Energy Corp. Mr. Mazanec currently serves as a Director of the National Fuel Gas Company and AEGIS Insurance Services, Inc. In addition, he is a member of the Board of Trustees of DePauw University in Indiana. Mr. Mazanec has served as a Dynegy Director since 2004. (1,2,3,5)

Mike Segal, 58
Mr. Segal is Chairman and Chief Executive Officer of the LS Power Group, a privately held power plant investor, developer and manager. Prior to co-founding LS Power, Mr. Segal served as co-head of Commercial Union Energy Corporation, where he was responsible for managing the Commercial Union Energy Limited Partnership, a partnership focused on investing in power generation projects. Mr. Segal was previously President of The Energy Systems Company, a private developer of cogeneration projects. He held various positions, including General Manager of Power Generation and Systems Planning, with LEMCO Engineers, Inc., or LEMCO, an electrical engineering and consulting firm. Prior to

LEMCO, Mr. Segal worked for the Department of Energy in the former Soviet Union. Mr. Segal began his service as a Dynegy Director in 2007. (4)

Howard B. Sheppard, 63

Mr. Sheppard served as an Assistant Treasurer of Chevron Corp. from 1988 to June 2008. He was employed by Chevron and its affiliates since the merger of Gulf Oil Corp. with Chevron in 1985. Prior to the merger, Mr. Sheppard held positions of increasing responsibility at Gulf Oil Corporation. He has served as a Dynegy Director since 2008. (1,3,4,5)

William L. Trubeck, 62

Mr. Trubeck is the former Executive Vice President and Chief Financial Officer of H&R Block, Inc. He previously served as Executive Vice President and Chief Financial Officer of Waste Management, Inc. Prior to these positions, Mr. Trubeck was Senior Vice President—Finance and Chief Financial Officer of International Multifoods, Inc., as well as President of its Latin American operations. Mr. Trubeck serves as a Director of YRC Worldwide. He has served as a Dynegy Director since 2003. (1,2,5)

Bruce A. Williamson, 49

Mr. Williamson is Chairman, President and Chief Executive Officer of Dynegy Inc. Prior to joining Dynegy, he was President and Chief Executive Officer of Duke Energy Global Markets. He also served as Senior Vice President of Business Development and Risk Management and President and Chief Executive Officer of Duke Energy International. Mr. Williamson was with PanEnergy Corp. in financial and business development leadership roles before its merger with Duke Power. He was also with Shell Oil Company for 14 years in exploration and production and finance roles. Mr. Williamson serves as a Director of Questar Corporation. Mr. Williamson has served as a Dynegy Director since 2002. He was named Chairman of the Board in 2004.

Dynegy Board Committees

(1) Audit and Compliance Committee
(2) Compensation and Human Resources Committee
(3) Corporate Governance and Nominating Committee
(4) Performance Review Committee
(5) Independent Director Committee

Executive Management Team

Bruce A. Williamson, 49
Chairman, President and Chief Executive Officer. He is responsible for the development and execution of Dynegy's business strategies with a focus on growth, sector leadership and delivering value to investors. Mr. Williamson joined Dynegy in 2002 as CEO and Director. He has served as President intermittently and was named Chairman of the Board in 2004.

J. Kevin Blodgett, 37
General Counsel and Executive Vice President, Administration. He is responsible for the company's legal, business services and administrative affairs, all of which support the company's operational, commercial and corporate areas. Mr. Blodgett joined Dynegy in 2000.

Charles C. Cook, 44
Executive Vice President, Commercial and Market Analytics. His responsibilities include overseeing all commercial functions related to Dynegy's power generation fleet. Mr. Cook joined Dynegy predecessor Destec Energy, Inc. in 1991.

Richard W. Eimer, Jr. 60
Executive Vice President of Operations. He is responsible for the operational management of Dynegy's fleet of power generation assets. Mr. Eimer began his career in 1971 with Illinois Power Company, a utility acquired by Dynegy in 2000.

Lynn A. Lednicky, 48
Executive Vice President, Asset Management, Development and Regulatory Affairs. Mr. Lednicky's role includes the execution of the company's commercial and operational strategies. He is also responsible for coordinating the company's regulatory and governmental affairs activities. Mr. Lednicky joined Dynegy predecessor Destec Energy, Inc. in 1991.

Holli C. Nichols, 38
Executive Vice President and Chief Financial Officer. She is responsible for the company's financial affairs, including finance and accounting, treasury, risk management, internal audit and credit agency relationships, as well as investor and public relations. Ms. Nichols joined Dynegy in 2000.

Corporate Information

Corporate Headquarters

Dynegy Inc.
1000 Louisiana Street
Suite 5800
Houston, Texas 77002
713-507-6400
1-800-633-4704
www.dynegy.com

Stock Exchange and Certification Information

In 2008, Dynegy's Chief Executive Officer provided to the NYSE the annual CEO certification regarding Dynegy's compliance with the NYSE's corporate governance listing standards. In addition, Dynegy's CEO and Chief Financial Officer filed with the U.S. Securities and Exchange Commission all required certifications regarding the quality of Dynegy's public disclosures in its 2008 periodic reports. Our Class A common stock is listed on the New York Stock Exchange under the symbol "DYN."

Investor Information

Individual stockholders, security analysts, portfolio managers and other institutional investors seeking information about the company should contact Dynegy Investor Relations at 713-507-6466, 1-800-800-8220 or by e-mail at ir@dynegy.com.

Additional copies of this report may be obtained free of charge by contacting Investor Relations or by visiting Dynegy's web site at www.dynegy.com.

This report is presented for the general information of the stockholders and not in connection with the sale, offer to sell or the solicitation of any offer to buy securities, nor is it intended to be a representation by the company of the value of its securities.

Media Information

Journalists seeking information about the company should contact the Dynegy Media Line at 713-767-5800.

Registrar and Transfer Agent

BNY Mellon Shareowner Services
480 Washington Boulevard
Jersey City, New Jersey 07310
1-888-921-5563
www.bnymellon.com/Shareowner

Annual Meeting

The Annual Meeting of Stockholders will be held on May 22, 2009.

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2008

☐ **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 ☒ No ☐
Dynegy Holdings Inc. Yes ☐ No ☒

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

Dynegy Inc. Yes ☐ No ☒
Dynegy Holdings Inc. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to the filing requirements for the past 90 days.

Dynegy Inc. Yes ☒ No ☐
Dynegy Holdings Inc. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Dynegy Inc. ☐
Dynegy Holdings Inc. ☒

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.	☒	☐	☐	☐
Dynegy Holdings Inc.	☐	☐	☒	☐

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

Dynegy Inc. Yes ☐ No ☒
Dynegy Holdings Inc. Yes ☐ No ☒

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.

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DYNEGY INC. and DYNEGY HOLDINGS INC.
FORM 10-K

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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 used to 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.

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PART I

DEFINITIONS

As used in this Form 10-K, the abbreviations contained herein have the meanings set forth in the glossary, 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.

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.

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 Units 1-2	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 calendar 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.

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.

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.

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.

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.

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.

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.

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.

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.

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 include, but 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.

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.

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.

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.

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.

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.

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.

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.

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).

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.

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:

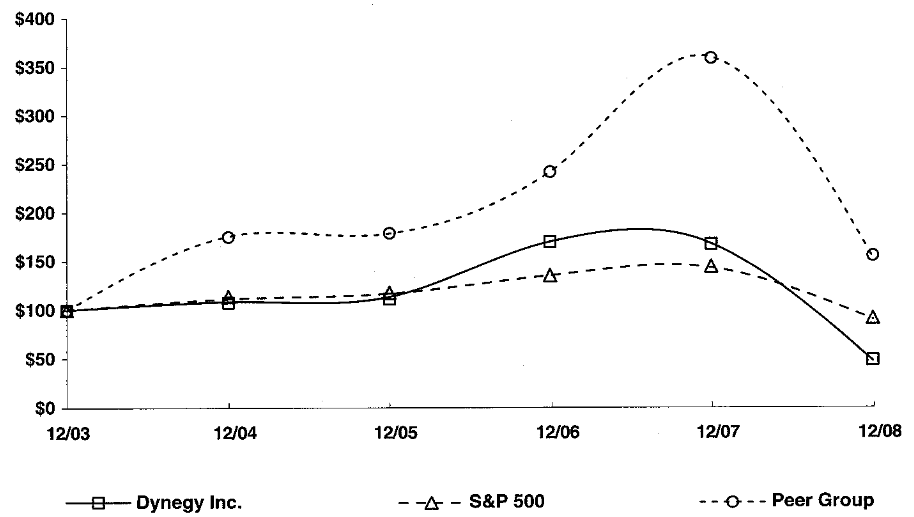
1. $100 was invested in Dynegy Class A common stock, the S&P 500, the Peer Group (as defined below) on December 31, 2003;
2. the returns of each component company in the Peer Group are weighed based on the market capitalization of such company at the beginning of the measurement period; and
3. dividends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

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.

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)

	December 31,				
	2008	2007	2006	2005	2004
	(in millions)				
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
Depreciation and amortization expense	(371)	(325)	(217)	(208)	(210)
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)

	December 31,				
	2008	2007	2006	2005	2004
	(in millions)				
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.

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.

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.

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.

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.

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	December 31, 2007
		(in millions)	
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.

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	2007	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.

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.

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.

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.

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.

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

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

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)

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

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)

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.

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	Other	Total
	(in millions)				
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	Other	Total
	(in millions)				
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.

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.

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

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.

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.

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.

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	Weighted Average Capacity Price
	(in MWs)	($ 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.

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.

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.

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.

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	$(100)
Risk-management gains recognized through the income statement in the period, net	145
Cash paid related to risk-management contracts settled in the period, net	135
Changes in fair value as a result of a change in valuation technique (1)	—
Non-cash adjustments and other (2)	(210)
Fair value of portfolio at December 31, 2008	$ (30)

(1) Our modeling methodology has been consistently applied.
(2) This amount consists of changes in value associated with fair value and cash flow hedges on debt.

The net risk-management liability of $30 million is the aggregate of the following line items on the consolidated balance sheets: Current Assets—Assets from risk-management activities, Other Assets—Assets from risk-management activities, Current Liabilities—Liabilities from risk-management activities and Other Liabilities—Liabilities from risk-management activities. During the period from December 31, 2007 to December 31, 2008, our Current Assets—Assets from risk-management activities and Current Liabilities—Liabilities from risk-management activities increased by approximately $900 million and $700 million, respectively. This increase was primarily a result of increased volumes of purchases and sales of commodities via financial instruments. These amounts are reflected gross on our consolidated balance sheets, as we do not offset fair value amounts recognized for derivative instruments executed with the same counterparties under a master netting agreement. However, a substantial portion of the financial instruments are with the same counterparty, resulting in a significantly smaller increase in our net risk-management liability, as denoted above. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk for further discussion regarding our counterparty credit exposure associated with risk-management accounts.

Risk-Management Asset and Liability Disclosures

The following table depicts the mark-to-market value and cash flow components, based on contract terms, of our net risk-management assets and liabilities at December 31, 2008. As opportunities arise to monetize positions that we believe will result in an economic benefit to us, we may receive or pay cash in periods other than those depicted below.

Net Risk-Management Asset and Liability Disclosures

	Total	2009	2010	2011	2012	2013	Thereafter
				(in millions)			
Mark-to-Market (1)	$ (30)	$144	$19	$(15)	$(12)	$(13)	$(153)
Cash Flow (2)	(113)	158	23	(19)	(16)	(16)	(243)

(1) Mark-to-market reflects the fair value of our net risk-management position, which considers time value, credit, price and other reserves necessary to determine fair value. Cash flows have been segregated between periods based on the delivery date required in the individual contracts.

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

The following table provides an assessment of net contract values by year as of December 31, 2008, based on our valuation methodology:

Net Fair Value of Risk-Management Portfolio

	Total	2009	2010	2011	2012	2013	Thereafter
				(in millions)			
Market Quotations (1)(2)	$(90)	$104	$ 5	$(16)	$(13)	$(14)	$(156)
Value Based on Models (2)	60	40	14	1	1	1	3
Total	$(30)	$144	$19	$(15)	$(12)	$(13)	$(153)

(1) Price inputs obtained from actively traded, liquid markets for commodities.

(2) The market quotations and prices based on models categorization differs from the SFAS No. 157 categories of Level 1, Level 2 and Level 3 due to the application of the different methodologies. Please read Note 6—Risk Management Activities, Derivatives and Financial Instruments—Fair Value Measurements for further discussion.

Derivative Contracts

The absolute notional contract amounts associated with our commodity risk-management and interest rate contracts are discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk below.

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

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

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

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

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

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

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

The modeling of the risk characteristics of our mark-to-market portfolio involves a number of assumptions and approximations. For 2008 and prior periods, we estimated VaR using a JP Morgan RiskMetrics™ approach assuming a one-day holding period. Inputs for the VaR calculation are prices, positions, instrument valuations and the variance-covariance matrix. VaR does not account for liquidity risk or the potential that adverse market conditions may prevent liquidation of existing market positions in a timely fashion. While management believes that these assumptions and approximations are reasonable, there is no uniform industry methodology for estimating VaR, and different assumptions and/or approximations could produce materially different VaR estimates.

Beginning in 2009, we are switching methodologies from a JP Morgan RiskMetrics™ approach to a Monte Carlo simulation-based methodology to better estimate risk for non-linear instruments, such as options. We have recalculated our daily and average VaR as of December 31, 2008 using the new methodology. The results using the new methodology did not result in a different VaR from that calculated using the JP Morgan RiskMetrics™ approach.

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

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

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

The following table sets forth the aggregate daily VaR and average VaR of the mark-to-market portion of our risk-management portfolio primarily associated with the GEN segments and the remaining legacy customer risk management business. The VaR calculation does not include market risks associated with the accrual portion of the risk-management portfolio that is designated as a cash flow hedge or a "normal purchase normal sale", nor does it include expected future production from our generating assets. The average year-to-date VaR increased during 2008 as compared to 2007 due to increased forward sales, higher commodity prices and a full year of VaR calculated on the financial instruments acquired in the Merger.

Daily and Average VaR for Mark-to-Market Portfolios

	December 31, 2008	December 31, 2007
	(in millions)	
One day VaR—95 percent confidence level	$21	$24
One day VaR—99 percent confidence level	$29	$35
Average VaR for the year-to-date period—95 percent confidence level	$42	$20

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

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

The following table represents our credit exposure at December 31, 2008 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary

	Investment Grade Quality	Non-Investment Grade Quality	Total
		(in millions)	
Type of Business:			
Financial Institutions	$198	$—	$198
Utility and Power Generators	4	2	6
Total	$202	$ 2	$204

As of December 31, 2008, we had a net risk management asset exposure to four financial institutions, which are all A rated or better. The largest exposure to a single financial institution was $83 million. We do not anticipate default risk inconsistent with these ratings given the systemic support from the TARP and expected additional federal support of the financial system, if necessary.

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

We are exposed to fluctuating interest rates related to variable rate financial obligations. As of December 31, 2008, the amount owed under our fixed rate debt instruments, as a percentage of the total amount owed under all of our debt instruments, was 75 percent. Adjusted for interest rate swaps, net notional fixed rate debt, as a percentage of total debt, was approximately 82 percent. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of December 31, 2008, it is estimated that a one percentage point interest rate movement in the average market interest rates (either higher or lower) over the twelve months ended December 31, 2009 would either decrease or increase interest expense by approximately $11 million. This exposure would be partially offset by an approximate $9 million increase in interest income related to the restricted cash balance of $850 million posted as collateral to support the term letter of credit facility. Over time, we may seek to adjust the variable rate exposure in our debt portfolio through the use of swaps or other financial instruments.

Derivative Contracts. The absolute notional financial contract amounts associated with our interest rate contracts were as follows at December 31, 2008 and 2007, respectively:

Absolute Notional Contract Amounts

	December 31, 2008	December 31, 2007
Cash flow hedge interest rate swaps (in millions of U.S. dollars) (1)	$ 471	$ 310
Fixed interest rate paid on swaps (percent)	5.32	5.32
Fair value hedge interest rate swaps (in millions of U.S. dollars)	$ 25	$ 25
Fixed interest rate received on swaps (percent)	5.70	5.70
Interest rate risk-management contracts (in millions of U.S. dollars)	$ 231	$ 231
Fixed interest rate paid (percent)	5.35	5.35
Interest rate risk-management contracts (in millions of U.S. dollars)	$ 206	$ 206
Fixed interest rate received (percent)	5.28	5.28

(1) Interest rate swap contracts related to our investment in the Plum Point Project.

Item 8. *Financial Statements and Supplementary Data*

Dynegy's and DHI's consolidated financial statements and financial statement schedules are set forth at pages F-1 through F-93 inclusive, found at the end of this annual report, and are incorporated herein by reference.

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

Not applicable.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of Dynegy's and DHI's management, including their Chief Executive Officer and their Chief Financial Officer, of the effectiveness of the design and operation of Dynegy's and DHI's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). This evaluation included consideration of the various processes carried out under the direction of Dynegy's disclosure committee. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002. Based on this evaluation, Dynegy's and DHI's CEO and CFO concluded that Dynegy's and DHI's disclosure controls and procedures were effective as of December 31, 2008.

Management's Report on Internal Control over Financial Reporting

Dynegy's and DHI's management are responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Dynegy's and DHI's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Dynegy's and DHI's internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of our company are being made only in accordance with authorizations of our management and directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of both Dynegy's and DHI's internal control over financial reporting as of December 31, 2008. In making this assessment, we used the criteria set forth in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this assessment and on those criteria, we concluded that both Dynegy's and DHI's internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of Dynegy's internal control over financial reporting as of December 31, 2008 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein. This annual report does not include an attestation report of DHI's registered public accounting firm regarding internal control over financial reporting. DHI's management report was not subject to attestation by DHI's registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit DHI to provide only management's report in this annual report.

Changes in Internal Controls Over Financial Reporting

There were no changes in Dynegy's and DHI's internal control over financial reporting that have materially affected or are reasonably likely to materially affect Dynegy's and DHI's internal control over financial reporting during the quarter ended December 31, 2008.

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

Not applicable.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Dynegy

Executive Officers. We intend to include the information with respect to our executive officers required by this Item 10 in Dynegy's definitive proxy statement for its 2009 annual meeting of stockholders under the heading "Executive Officers;" which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

Code of Ethics. We have adopted a Code of Ethics within the meaning of Item 406(b) of Regulation S-K. This Code of Ethics applies to our Chief Executive Officer, Chief Financial Officer, Controller and other persons performing similar functions designated by the Chief Financial Officer, and is filed as an exhibit to this Form 10-K.

Other Information. We intend to include the other information required by this Item 10 in Dynegy's definitive proxy statement for its 2009 annual meeting of stockholders under the headings "Proposal 1—Election of Directors" and "Compliance with Section 16(a) of the Exchange Act," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

DHI

Omitted pursuant to General Instruction (1)(2)(c) of Form 10-K.

Item 11. *Executive Compensation*

Dynegy. We intend to include information with respect to executive compensation in Dynegy's definitive proxy statement for its 2009 annual meeting of stockholders under the heading "Executive Compensation", which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

DHI. Omitted pursuant to General Instruction (1)(2)(c) of Form 10-K.

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

Dynegy. The following table sets forth certain information as of December 31, 2008 as it relates to Dynegy's equity compensation plans for its Class A common stock, the only class with respect to which Dynegy offers equity compensation.

Securities Authorized for Issuance Under Equity Compensation Plans

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	5,963,988	$12.20	10,949,552
Equity compensation plans not approved by securityholders (1)	2,852,574	$11.38	1,931,762
Total	8,816,562	$11.93	12,881,314

(1) The plans that were not approved by Dynegy's security holders are as follows: Extant Inc. 401(K) Plan, Dynegy 2001 Non-Executive Stock Incentive Plan and Dynegy UK Plan. Please read Note 20—Capital Stock—Stock Award Plans for a brief description of Dynegy's equity compensation plans, including these plans.

We intend to include information regarding ownership of Dynegy's outstanding securities in Dynegy's definitive proxy statement for its 2009 annual meeting of stockholders under the heading "Security Ownership of Certain Beneficial Owners and Management", which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

DHI. Omitted pursuant to General Instruction (1)(2)(c) of Form 10-K.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Dynegy. We intend to include the information regarding related party transactions in Dynegy's definitive proxy statement for its 2009 annual meeting of stockholders under the headings "Corporate Governance" and "Transactions with Related Persons, Promoters and Certain Control Persons", which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

DHI. Omitted pursuant to General Instruction (1)(2)(c) of Form 10-K.

Item 14. *Principal Accountant Fees and Services*

Dynegy. We intend to include information regarding principal accountant fees and services in Dynegy's definitive proxy statement for its 2009 annual meeting of stockholders under the heading "Independent Registered Public Auditors—Principal Accountant Fees and Services", which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

DHI. DHI is an indirect, wholly owned subsidiary of Dynegy and does not have a separate audit committee. Information regarding principal accountant fees and services for Dynegy and its consolidated subsidiaries, including DHI, will be contained in Dynegy's definitive proxy statement for its 2009 annual meeting of stockholders under the heading "Independent Registered Public Auditors—Principal Accountant Fees and Services". Such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

PART IV

Item 15. *Exhibits, Financial Statement Schedules*

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

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

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

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

Exhibit Number	Description
2.1	—Plan of Merger, Contribution and Sale Agreement, dated September 14, 2006 by and among Dynegy Inc., LSP Gen Investors, LP, LS Power Partners, LP, LS Power Equity Partners PIE I, L.P., LS Power Equity Partners, L.P., LS Power Associates, L.P., Falcon Merger Sub Co. and Dynegy Acquisition, Inc. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
2.2	—Limited Liability Company Membership Interests and Stock Purchase Agreement, dated as of September 14, 2006, among LS Power Associates, L.P., LS Power Equity Partners, L.P., LS Power Equity Partners PIE I, L.P., LS Power Partners, L.P. and Kendall Power LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1- 15659).
3.1	—Amended and Restated Certificate of Incorporation of Dynegy Inc. (formerly named Dynegy Acquisitions, Inc.) (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-8 of Dynegy Inc. filed on April 2, 2007, File No. 333-141810).
3.2	—Amended and Restated Bylaws of Dynegy Inc. (formerly named Dynegy Acquisitions, Inc.) (incorporated by reference to Exhibit 4.2 to the Registration Statement on Form S-8 of Dynegy Inc. filed on April 2, 2007, File No. 333-141810).
3.3	—Restated Certificate of Incorporation of Dynegy Holdings Inc. (incorporated by reference to Exhibit 3.1 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Holdings Inc., File No. 000-29311).
3.4	—Amended and Restated Bylaws of Dynegy Holdings Inc. (incorporated by reference to Exhibit 3.2 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Holdings Inc., File No. 000-29311).
4.1	—Subordinated Debenture Indenture between NGC Corporation and The First National Bank of Chicago, as Debenture Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.2	—Amended and Restated Declaration of Trust among NGC Corporation, Wilmington Trust Company, as Property Trustee and Delaware Trustee, and the Administrative Trustees named therein, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.3	—Series A Capital Securities Guarantee Agreement executed by NGC Corporation and The First National Bank of Chicago, as Guarantee Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).

Exhibit Number	Description
4.4	—Common Securities Guarantee Agreement of NGC Corporation, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.5	—Registration Rights Agreement, dated as of May 28, 1997, among NGC Corporation, NGC Corporation Capital Trust I, Lehman Brothers, Salomon Brothers Inc. and Smith Barney Inc. (incorporated by reference to Exhibit 4.11 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.6	—Indenture, dated as of September 26, 1996, restated as of March 23, 1998, and amended and restated as of March 14, 2001, between Dynegy Holdings Inc. and Bank One Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2000 of Dynegy Holdings Inc., File No. 000-29311).
4.7	—First Supplemental Indenture, dated July 25, 2003 to that certain Indenture, dated as of September 26, 1996, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659).
4.8	—Second Supplemental Indenture, dated as of April 12, 2006, to that certain Indenture, originally dated as of September 26, 1996, as amended and restated as of March 23, 1998 and again as of March 14, 2001, by and between Dynegy Holdings Inc. and Wilmington Trust Company (as successor to JPMorgan Chase Bank, N.A.), as trustee, as supplemented by that certain First Supplemental Indenture, dated as of July 25, 2003 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 12, 2006, File No. 1-15659).
4.9	—Third Supplemental Indenture, dated as of May 24, 2007, to that certain Indenture, originally dated as of September 26, 1996, as amended and restated as of March 23, 1998 and again as of March 14, 2001, by and between Dynegy Holdings Inc. and Wilmington Trust Company (as successor to JPMorgan Chase Bank, N.A.), as trustee, as supplemented by that certain First Supplemental Indenture, dated as of July 25, 2003, and that certain Second Supplemental Indenture, dated as of April 12, 2006 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on May 25, 2007, File No. 000-29311).
4.10	—Fourth Supplemental Indenture, dated as of May 24, 2007, to that certain Indenture, originally dated as of September 26, 1996, as amended and restated as of March 23, 1998 and again as of March 14, 2001, by and between Dynegy Holdings Inc. and Wilmington Trust Company (as successor to JPMorgan Chase Bank, N.A.), as trustee, as supplemented by that certain First Supplemental Indenture, dated as of July 25, 2003, that certain Second Supplemental Indenture, dated as of April 12, 2006, and that certain Third Supplemental Indenture, dated as of May 24, 2007 (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on May 25, 2007, File No. 000-29311).
4.11	—Registration Rights Agreement, effective as of July 21, 2006, by and among Dynegy Holdings Inc. RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 2006, File No. 1-15659).
4.12	—Registration Rights Agreement, dated as of May 24, 2007, by and among Dynegy Holdings Inc. and the several initial purchasers party thereto (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on May 25, 2007, File No. 000-29311).
4.13	—Trust Indenture, dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/ Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).

Exhibit Number	Description
4.14	—First Supplemental Indenture, dated as of January 1, 1993, to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.23 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
4.15	—Second Supplemental Indenture, dated as of October 23, 2001, to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.24 to the Annual Report on Form 10- K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
4.16	—Global Note representing the 9.00 percent Secured Bonds due 2013 of Sithe/Independence Power Partners, L.P. (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2005 of Dynegy Inc., File No. 1-15659).
4.17	—Shareholder Agreement, dated as of September 14, 2006, among Dynegy Acquisition, Inc. and LS Power Partners, L.P., LS Power Associates, L.P., LS Power Equity Partners, L.P., LS Power Equity Partners PIE I, L.P. and LSP Gen Investors, L.P. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
4.18	—Registration Rights Agreement, dated as of September 14, 2006, among Dynegy Acquisition, Inc., LS Power Partners, L.P., LS Power Associates, L.P., LS Power Equity Partners, L.P., LS Power Equity Partners PIE I, L.P. and LSP Gen Investors, L.P. (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
4.19	—Lock-Up Agreement, dated as of September 14, 2006, by and among LSP Gen Investors, LP, LS Power Partners, LP, LS Power Associates, L.P., LS Power Equity Partners PIE I, LP, LS Power Equity Partners, L.P. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.5 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
10.1	—Purchase Agreement, dated August 1, 2003, among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.2	—Purchase Agreement, dated August 1, 2003, among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.3	—Purchase Agreement, dated September 30, 2003, among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 15, 2003, File No. 1-15659).
10.4	—Purchase Agreement, dated as of March 29, 2006, for the sale of $750,000,000 aggregate principal amount of the 8.375 percent Senior Unsecured Notes due 2016 of Dynegy Holdings Inc. among Dynegy Holdings Inc. and the several initial purchasers named therein (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2006 of Dynegy Inc., File No. 1-15659).
10.5	—Purchase Agreement, dated as of May 17, 2007, by and between Dynegy Holdings Inc. and J.P. Morgan Securities Inc. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for Quarterly Period Ended June 30, 2007 of Dynegy Holdings Inc., File No. 000-29311).

Exhibit Number	Description
10.6	—Stock Purchase Agreement, dated as of November 1, 2004, among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.48 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc. File No. 1-15659).
10.7	—Amendment to Stock Purchase Agreement (Special Payroll Payment), dated as of January 28, 2005, among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc. File No. 1-15659).
10.8	—Amendment to Stock Purchase Agreement, dated as of January 31, 2005, among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
10.9	—Amendment to Stock Purchase Agreement (Luz Sale), dated as of January 31, 2005, among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
10.10	—Exchange Agreement, dated as of July 21, 2006, by and among Dynegy Holdings Inc., RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 2006, File No. 1-15659).
10.11	—Corporate Opportunity Agreement, dated as of September 14, 2006, between Dynegy Acquisition, Inc. and LS Power Development, LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
10.12	—Limited Liability Company Agreement of DLS Power Development Company, LLC, dated April 2, 2007, by and between LS Power Associates, L.P. and Dynegy Inc. (formerly named Dynegy Acquisition, Inc.) (incorporated by reference to Exhibit 10.15 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.13	—Amended and Restated Limited Liability Company Agreement of DLS Power Holdings, LLC, dated April 2, 2007, by and between LS Power Associates, L.P. and Dynegy Inc. (formerly named Dynegy Acquisition, Inc.) (incorporated by reference to Exhibit 10.14 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
**10.14	—Dissolution Agreement by and between Dynegy Inc. and LS Power Associates, L.P., effective January 1, 2009.
10.15	—Fifth Amended and Restated Credit Agreement, dated as of April 2, 2007, by and among Dynegy Holdings Inc., as borrower, Dynegy Inc. (formerly named Dynegy Acquisition, Inc.) and Dynegy Inc., as parent guarantors, the other guarantors party thereto, the lenders party thereto and various other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.16	—Amendment No. 1, dated as of May 24, 2007, to the Fifth Amended and Restated Credit Agreement, dated as of April 2, 2007, by and among Dynegy Holdings Inc., as borrower, Dynegy Inc. and Dynegy Illinois Inc., as parent guarantors, the other guarantors party thereto, the lenders party thereto and various other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on May 25, 2007, File No. 000-29311).

Exhibit Number	Description
10.17	—Amendment No. 2, dated as of September 30, 2008, to the Fifth Amended and Restated Credit Agreement, dated as of April 2, 2007, by and among Dynegy Holdings Inc., as borrower, Dynegy Inc. and Dynegy Illinois Inc., as parent guarantors, the other guarantors party thereto, the lenders party thereto and various other parties thereto (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Dynegy Holdings Inc. filed on December 6, 2008, File No. 000-29311).
**10.18	—Amendment No. 3, dated as of February 13, 2009, to the Fifth Amended and Restated Credit Agreement, dated as of April 2, 2007 , by and among Dynegy Holdings Inc., as borrower, Dynegy Inc. and Dynegy Illinois Inc., as parent guarantors, the other guarantors party thereto, the lenders party thereto and various other parties thereto.
10.19	—Second Amended and Restated Security Agreement, dated April 2, 2007, by and among Dynegy Holdings Inc., as Borrower, the initial grantors party thereto, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.20	—Facility and Security Agreement, dated June 17, 2008, by and among Dynegy Holdings Inc., Morgan Stanley Capital Group Inc., as lender and as issuing bank and as collateral agent (as incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 18, 2008, File No. 001-33443).
10.21	—Credit Agreement, dated as of March 29, 2007, by and among Plum Point Energy Associates, LLC, as borrower, and the lenders and other parties thereto (incorporated by reference to Exhibit 10.10 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
**10.22	—First Amendment to Credit Agreement by and among Plum Point Energy Associates, LLC, as borrower, and the lenders and other parties thereto, effective December 13, 2007.
10.23	—Collateral Agency and Intercreditor Agreement, dated as of March 29, 2007, by and among Plum Point Energy Associates, LLC, as borrower, PPEA Holding Company, LLC, as Pledgor, The Bank of New York, as collateral agent, The Royal Bank of Scotland, as Administrative Agent, AMBAC Assurance Corporation, as Loan Insurer, and the other parties thereto (incorporated by reference to Exhibit 10.11 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.24	—Loan Agreement, dated as of April 1, 2006, by and between the City of Osceola, Arkansas and Plum Point Energy Associates, LLC (incorporated by reference to Exhibit 10.12 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.25	—Trust Indenture, dated as of April 1, 2006, by and between the City of Osceola, Arkansas and Regions Bank, as trustee (incorporated by reference to Exhibit 10.13 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.26	—First Supplemental Trust Indenture dated as of April 24, 2007, by and between the City of Osceola, Arkansas and Regions Bank, as trustee (incorporated by reference to Exhibit 10.28 to the Annual Report on Form 10-K of Dynegy Holdings Inc. filed on February 28, 2008, File No. 000-29311).
10.27	—Dynegy Inc. Executive Severance Pay Plan, as amended and restated effective as of January 1, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 4, 2008, File No. 001-33443). ††

Exhibit Number	Description
10.28	—Dynegy Inc. Executive Change in Control Severance Pay Plan effective April 3, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 8, 1008, File No. 001-33443). ††
10.29	—Dynegy Inc. Change In Control Severance Pay Plan effective April 3, 2008 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on May 8, 2008, File No. 001- 33443).
10.30	—Dynegy Inc. Severance Pay Plan, as amended and restated effective as of January 30, 2008 (incorporated by reference to Exhibit 10.37 to the Annual Report of Dynegy Inc. on Form 10-K filed on February 28, 2008, File No. 001-33443). ††
10.31	—Dynegy Inc. Excise Tax Reimbursement Policy, effective January 1, 2008 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on January 4, 2008, File No. 001-33443). ††
**10.32	—Dynegy Northeast Generation, Inc. Savings Incentive Plan, as amended and restated, effective January 1, 2009. ††
**10.33	—Dynegy Inc. 401(k) Savings Plan, as amended and restated effective January 1, 2009. ††
**10.34	—Dynegy Midwest Generation, Inc. 401(k) Savings Plan, as amended and restated, effective as January 1, 2009.
**10.35	—Dynegy Midwest Generation, Inc. 401(k) Savings Plan for Employees Covered under a Collective Bargaining Agreement, as amended and restated, effective January 1, 2009.
10.36	—Dynegy Inc. Restoration 401(k) Savings Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).
10.37	—First Amendment to the Dynegy Inc. Restoration 401(k) Savings Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443). ††
10.38	—Dynegy Inc. Restoration Pension Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443). ††
10.39	—First Amendment to the Dynegy Inc. Restoration Pension Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443). ††
**10.40	—Sithe Pension Account Plan, amended and restated, effective January 1, 2007.
**10.41	—Seventh [First] Amendment to the Sithe Pension Account Plan, as amended, effective January 1, 2008.
**10.42	—Second Amendment to the Sithe Pension Account Plan, as amended, effective January 1, 2008.
10.43	—Form of Non-Qualified Stock Option Award Agreement between Dynegy Inc., all of its affiliates and Bruce A. Williamson (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††
10.44	—Form of Non-Qualified Stock Option Award Agreement between Dynegy Inc., all of its affiliates and Jason Hochberg (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††

Exhibit Number	Description
10.45	—Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††
10.46	—Form of Restricted Stock Award Agreement between Dynegy Inc., all of its affiliates and Bruce A. Williamson (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††
10.47	—Form of Restricted Stock Award Agreement between Dynegy Inc., all of its affiliates and Jason Hochberg (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††
10.48	—Form of Restricted Stock Award Agreement (Managing Directors and Above) (incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††
10.49	—Form of Restricted Stock Award Agreement (Directors and Below) (incorporated by reference to Exhibit 10.13 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443).
10.50	—Form of Performance Award Agreement between Dynegy Inc., all of its affiliates and Bruce A. Williamson (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††
10.51	—Form of Performance Award Agreement between Dynegy Inc., all of its affiliates and Jason Hochberg (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††
10.52	—Form of Performance Award Agreement (incorporated by reference to Exhibit 10.14 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2008 of Dynegy Inc. filed on May 8, 2008, File No. 1-33443). ††
10.53	—Dynegy Inc. Deferred Compensation Plan, amended and restated, effective January 1, 2002(incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080). ††
10.54	—Amendment to the Dynegy Inc. Deferred Compensation Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.38 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311). ††
**10.55	—Dynegy Inc. Deferred Compensation Plan for Certain Directors, as amended and restated, effective January 1, 2008. ††
**10.56	—Trust under Dynegy Inc. Deferred Compensation Plan for Certain Directors, effective January 1, 2009. ††
10.57	—Dynegy Inc. Incentive Compensation Plan, as amended and restated effective January 1, 2006 (incorporated by reference to Exhibit 10.36 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2005 of Dynegy Inc. File No. 1-15659). ††
10.58	—First Amendment to the Dynegy Inc. Incentive Compensation Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.32 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311). ††
10.59	—Dynegy Inc. 1999 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156). ††

Exhibit Number	Description
10.60	—First Amendment to the Dynegy Inc. 1999 Long Term Incentive Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.33 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311). ††
10.61	—Dynegy Inc. 2000 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156). ††
10.62	—Amendment to the Dynegy Inc. 2000 Long Term Incentive Plan effective January 1, 2006 (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659). ††
10.63	—Second Amendment to the Dynegy Inc. 2000 Long Term Incentive Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.34 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311). ††
10.64	—Dynegy Inc. 2002 Long Term Incentive Plan (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 9, 2002). ††
10.65	—Amendment to the Dynegy Inc. 2002 Long Term Incentive Plan, effective January 1, 2006 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659). ††
10.66	—Second Amendment to the Dynegy Inc. 2002 Long Term Incentive Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.36 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311). ††
10.67	—Dynegy Inc. 2001 Non-Executive Stock Incentive Plan (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.68	—First Amendment to the Dynegy Inc. 2001 Non-Executive Stock Incentive Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.35 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
**10.69	—Dynegy Inc. Retirement Plan, as amended and restated, effective January 1, 2009.
**10.70	—Dynegy Inc. Comprehensive Welfare Benefits Plan, effective January 1, 2002.
**10.71	—First Amendment to the Dynegy Inc. Comprehensive Welfare Benefits Plan, dated September 29, 2004.
**10.72	—Second Amendment to the Dynegy Inc. Comprehensive Welfare Benefits Plan, dated January 1, 2005.
**10.73	—Third Amendment to the Dynegy Inc. Comprehensive Welfare Benefits Plan, dated January 28, 2005.
**10.74	—Fourth Amendment to the Dynegy Inc. Comprehensive Welfare Benefits Plan, dated April 20, 2005.
**10.75	—Fifth Amendment to the Dynegy Inc. Comprehensive Welfare Benefits Plan, dated January 1, 2006.
10.76	—Sixth Amendment to the Dynegy Inc. Comprehensive Welfare Benefits Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.31 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
**10.77	—Dynegy Northeast Generation, Inc. Comprehensive Welfare Benefits Plan, dated as of January 1, 2002.

Exhibit Number	Description
**10.78	—Amendment One to the Dynegy Northeast Generation, Inc. Comprehensive Welfare Benefits Plan, dated as of April 20, 2005.
**10.79	—Amendment Two to the Dynegy Northeast Generation, Inc. Comprehensive Welfare Benefits Plan, dated as of January 1, 2006.
**10.80	—Dynegy Northeast Generation, Inc. Retirement Income Plan, as amended and restated, effective January 1, 2009.
10.81	—Master Trust Agreement, dated as of January 1, 2002 (Vanguard) (incorporated by reference to Exhibit 10.45 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.82	—Agreement and Amendment to Master Trust Agreement, dated as of December 31, 2003 (Vanguard) (incorporated by reference to Exhibit 10.46 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.83	—Amendment No. 2 to The Master Trust Agreement, dated as of September 29, 2004 (Vanguard) (incorporated by reference to Exhibit 10.47 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.84	—Amendment to Master Trust Agreement, dated as of January 1, 2006 (Vanguard) (incorporated by reference to Exhibit 10.48 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.85	—Amendment to Master Trust Agreement (Vanguard Fiduciary Trust Company), dated as of April 2, 2007 (incorporated by reference to Exhibit 10.55 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.86	—Trust Agreement—DMG 401(k) Savings Plan for Employees Covered under a Collective Bargaining Agreement (Vanguard), dated as of January 1, 2002 (incorporated by reference to Exhibit 10.5 to Form S-4 of Dynegy Illinois Inc., filed on January 11, 2002, File No. 333-76570).
10.87	—Amendment to Trust Agreement—DMG 401(k) Savings Plan for Employees Covered under a Collective Bargaining Agreement (Vanguard), dated as of September 29, 2004 (incorporated by reference to Exhibit 10.49 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.88	—Amendment to Trust Agreement—DMG 401(k) Savings Plan for Employees Covered under a Collective Bargaining Agreement (Vanguard), dated as of January 1, 2006 (incorporated by reference to Exhibit 10.50 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.89	—Amendment to Trust Agreement—DMG 401(k) Savings Plan for Employees Covered under a Collective Bargaining Agreement (Vanguard), dated as of April 2, 2007 (incorporated by reference to Exhibit 10.52 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.90	—Trust Agreement—DMG 401(k) Savings Plan (Vanguard), dated as of September 29, 2004 (incorporated by reference to Exhibit 10.4 to Form S-4 of Dynegy Illinois Inc., filed on January 11, 2002, File No. 333-76570).
10.91	—Amendment to Trust Agreement—DMG 401(k) Savings Plan (Vanguard), dated as of September 29, 2004 (incorporated by reference to Exhibit 10.49 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).

Exhibit Number	Description
10.92	—Amendment to Trust Agreement—DMG 401(k) Savings Plan (Vanguard), dated as of January 1, 2006 (incorporated by reference to Exhibit 10.50 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.93	—Amendment to Trust Agreement—DMG 401(k) Savings Plan (Vanguard), dated as of April 2, 2007 (incorporated by reference to Exhibit 10.51 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.94	—Dynegy Inc. 401(k) Savings Plan Trust Agreement, effective January 1, 2002 (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76570). ††
10.95	—Amendment to Trust Agreement—Dynegy Inc. 401(k) Savings Plan (Vanguard), dated as of January 1, 2006 (incorporated by reference to Exhibit 10.52 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.96	—Amendment to Trust Agreement—Dynegy Inc. 401(k) Savings Plan (Vanguard), dated as of April 2, 2007 (incorporated by reference to Exhibit 10.53 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
**10.97	—Trust Agreement—Dynegy Northeast Generation Inc. Savings Incentive Plan, dated as of December 31, 2003 (incorporated by reference to Exhibit.
**10.98	—Amendment to Trust Agreement—Dynegy Northeast Generation Inc. Savings Incentive Plan, dated as of January 1, 2006.
**10.99	—Amendment to Trust Agreement—Dynegy Northeast Generation Inc. Savings Incentive Plan, dated as of April 2, 2007.
10.100	—Dynegy Inc. Deferred Compensation Plan Trust Agreement (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080). ††
10.101	—Amendment to Dynegy Inc. Deferred Compensation Plan Trust Agreement (Vanguard), dated as of April 2, 2007 (incorporated by reference to Exhibit 10.54 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311). ††
**10.102	—Dynegy Inc. Master Retirement Trust, dated as of December 13, 2001.
**10.103	—Amendment No. One to The Dynegy Inc. Master Retirement Trust, dated as of August 5, 2002.
**10.104	—Amendment No. Two to The Dynegy Inc. Master Retirement Trust, dated as of September 30, 2004.
**10.105	—Amendment No. Three to The Dynegy Inc. Master Retirement Trust, dated as of December 1, 2005.
**10.106	—Amendment No. Four to The Dynegy Inc. Master Retirement Trust, dated as of September 25, 2006.
**10.107	—Amendment No. Five to The Dynegy Inc. Master Retirement Trust, dated as of April 2, 2007.
10.108	—Purchase Agreement, dated as of May 17, 2007, by and between Dynegy Holdings Inc. and J.P. Morgan Securities Inc. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for Quarterly Period Ended June 30, 2007 of Dynegy Holdings Inc., File No. 000-29311).
10.109	—Equity Commitment Agreement among Sandy Creek Energy Associates, L.P., Dynegy Sandy Creek Holdings, LLC and Credit Suisse dated August 29, 2007 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on September 5, 2007, File No. 000-29311).

Exhibit Number	Description
10.110	—Equity Commitment Agreement among Sandy Creek Energy Associates, L.P., Sandy Creek Holdings, LLC and Credit Suisse dated August 29, 2007 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on September 5, 2007, File No. 000-29311).
10.111	—Baldwin Consent Decree, approved May 27, 2005 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 31, 2005, File No. 1-15659).
14.1	—Dynegy Inc. Code of Ethics for Senior Financial Professionals (incorporated by reference to Exhibit 14.1 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1- 15659).
16.1	— Letter of PricewaterhouseCoopers LLP, as amended, dated May 15, 2007 (incorporated by reference to Exhibit 16.1A to the Current Report on Form 8-K/A of Dynegy Holdings Inc. filed on May 15, 2007, File No. 001-33443).
**21.1	—Subsidiaries of the Registrant (Dynegy Inc.).
21.2	—Subsidiaries of the Registrant (Dynegy Holdings Inc.)—Omitted pursuant to General Instruction (1)(2)(c) of Form 10-K.
**23.1	—Consent of Ernst & Young LLP (Dynegy Inc.).
**23.2	—Consent of PricewaterhouseCoopers LLP (Dynegy Inc.).
**23.3	—Consent of Ernst & Young LLP (Dynegy Holdings Inc.).
**23.4	—Consent of PricewaterhouseCoopers LLP (Dynegy Holdings Inc.).
**31.1	—Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.1(a)	—Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	—Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2(a)	—Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	—Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.1(a)	—Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2	—Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2(a)	—Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

** Filed herewith

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

†† Management contract or compensation plan.

SIGNATURES

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

DYNEGY INC.

Date: February 26, 2009

By: /s/ BRUCE A. WILLIAMSON

Bruce A. Williamson
Chairman of the Board, President and Chief Executive Officer

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

/s/ BRUCE A. WILLIAMSON **Bruce A. Williamson**	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	February 26, 2009
/s/ HOLLI C. NICHOLS **Holli C. Nichols**	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 26, 2009
/s/ CAROLYN J. STONE **Carolyn J. Stone**	Senior Vice President and Controller (Principal Accounting Officer)	February 26, 2009
/s/ JAMES T. BARTLETT **James T. Bartlett**	Director	February 26, 2009
/s/ DAVID W. BIEGLER **David W. Biegler**	Director	February 26, 2009
/s/ THOMAS D. CLARK, JR. **Thomas D. Clark, Jr.**	Director	February 26, 2009
/s/ VICTOR E. GRIJALVA **Victor E. Grijalva**	Director	February 26, 2009
/s/ PATRICIA A. HAMMICK **Patricia A. Hammick**	Director	February 26, 2009
/s/ FRANK E. HARDENBERGH **Frank E. Hardenbergh**	Director	February 26, 2009
/s/ GEORGE L. MAZANEC **George L. Mazanec**	Director	February 26, 2009
/s/ MIKHAIL SEGAL **Mikhail Segal**	Director	February 26, 2009
/s/ HOWARD B. SHEPPARD **Howard B. Sheppard**	Director	February 26, 2009
/s/ WILLIAM L. TRUBECK **William L. Trubeck**	Director	February 26, 2009

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

DYNEGY HOLDINGS INC.

Date: February 26, 2009

By: /s/ BRUCE A. WILLIAMSON

Bruce A. Williamson
President and Chief Executive Officer

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

/s/ BRUCE A. WILLIAMSON **Bruce A. Williamson**	President and Chief Executive Officer (Principal Executive Officer)	February 26, 2009
/s/ HOLLI C. NICHOLS **Holli C. Nichols**	Executive Vice President, Chief Financial Officer, Treasurer and Director (Principal Financial Officer)	February 26, 2009
/s/ CAROLYN J. STONE **Carolyn J. Stone**	Senior Vice President and Controller (Principal Accounting Officer)	February 26, 2009
/s/ J. KEVIN BLODGETT **J. Kevin Blodgett**	Director	February 26, 2009
/s/ LYNN A. LEDNICKY **Lynn A. Lednicky**	Director	February 26, 2009

DYNEGY INC. AND DYNGEGY HOLDINGS INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.

We have audited the accompanying consolidated balance sheets of Dynegy Inc. as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' equity, comprehensive income (loss) and cash flows for the years then ended. Our audits also included the financial statement schedules listed in the Index at Item 15(a) as of and for the years ended December 31, 2008 and 2007. These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Dynegy Inc. at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2007 the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes.*

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Dynegy Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 26, 2009

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.

We have audited Dynegy Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Dynegy Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Dynegy Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2008 consolidated financial statements of Dynegy Inc. and our report dated February 26, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 26, 2009

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Dynegy Inc.:

In our opinion, the accompanying consolidated statements of operations, comprehensive income (loss), stockholders' equity and cash flows for the year ended December 31, 2006 present fairly, in all material respects, the results of operations and cash flows of Dynegy Inc. and its subsidiaries (the "Company") for the year ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules for the year ended December 31, 2006 present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 19, the Company is the subject of substantial litigation. The Company's ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies", that might result from the ultimate resolution of such matters.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2007, except for the effects of discontinued operations described in Note 4, as to which the date is May 14, 2007 for Calcasieu and February 28, 2008 for CoGen Lyondell, and except for the change in reportable segments described in Note 22, as to which the date is February 26, 2009.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholder
Dynegy Holdings Inc.

We have audited the accompanying consolidated balance sheets of Dynegy Holdings Inc. as of December 31, 2008 and 2007, and the related consolidated statements of operations, cash flows, comprehensive income (loss), and stockholder's equity for the years then ended. Our audits also included the financial statement schedule listed in the Index at Item 15(a) as of and for the years ended December 31, 2008 and 2007. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Dynegy Holdings Inc. at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2007 the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*.

/s/ Ernst & Young LLP
Houston, Texas
February 26, 2009

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholder of Dynegy Holdings Inc.:

In our opinion, the accompanying consolidated statements of operations, comprehensive income (loss), stockholder's equity and cash flows for the year ended December 31, 2006 present fairly, in all material respects, the results of operations and cash flows of Dynegy Holdings Inc. and its subsidiaries (the "Company") for the year ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for the year ended December 31, 2006, presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 19, the Company is the subject of substantial litigation. The Company's ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies", that might result from the ultimate resolution of such matters.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 16, 2007, except for the effects of discontinued
operations described in Note 4, as to which the date is May 14,
2007 for Calcasieu and August 16, 2007 for CoGen Lyondell,
except for the effects of the transfer of entities under
common control described in Note 3, as to which the date is
August 16, 2007, and except for the change in reportable segments
described in Note 22, as to which the date is February 26, 2009.

DYNEGY INC.

CONSOLIDATED BALANCE SHEETS
(in millions, except share data)

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 693	$ 328
Restricted cash and investments	87	104
Short-term investments	25	—
Accounts receivable, net of allowance for doubtful accounts of $22 and $20, respectively	340	426
Accounts receivable, affiliates	1	1
Inventory	184	199
Assets from risk-management activities	1,263	358
Deferred income taxes	6	45
Prepayments and other current assets	204	145
Assets held for sale (Note 4)	—	57
Total Current Assets	2,803	1,663
Property, Plant and Equipment	10,869	10,689
Accumulated depreciation	(1,935)	(1,672)
Property, Plant and Equipment, Net	8,934	9,017
Other Assets		
Unconsolidated investments	15	79
Restricted cash and investments	1,158	1,221
Assets from risk-management activities	114	55
Goodwill	433	438
Intangible assets	437	497
Deferred income taxes	—	6
Accounts receivable, affiliates	4	—
Other long-term assets	315	245
Total Assets	$14,213	$13,221
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 303	$ 292
Accrued interest	56	56
Accrued liabilities and other current liabilities	160	201
Liabilities from risk-management activities	1,119	397
Notes payable and current portion of long-term debt	64	51
Liabilities held for sale (Note 4)	—	2
Total Current Liabilities	1,702	999
Long-term debt	5,872	5,739
Long-term debt to affiliates	200	200
Long-Term Debt	6,072	5,939
Other Liabilities		
Liabilities from risk-management activities	288	116
Deferred income taxes	1,166	1,250
Other long-term liabilities	500	388
Total Liabilities	9,728	8,692
Minority Interest	(30)	23
Commitments and Contingencies (Note 19)		
Stockholders' Equity		
Class A Common Stock, $0.01 par value, 2,100,000,000 shares authorized at December 31, 2008 and December 31, 2007; 505,821,277 shares and 502,819,794 shares issued and outstanding at December 31, 2008 and December 31, 2007, respectively	5	5
Class B Common Stock, $0.01 par value, 850,000,000 shares authorized at December 31, 2008 and December 31, 2007; 340,000,000 shares issued and outstanding at December 31, 2008 and December 31, 2007, respectively	3	3
Additional paid-in capital	6,485	6,463
Subscriptions receivable	(2)	(5)
Accumulated other comprehensive loss, net of tax	(215)	(25)
Accumulated deficit	(1,690)	(1,864)
Treasury stock, at cost, 2,568,286 shares and 2,449,259 shares at December 31, 2008 and December 31, 2007, respectively	(71)	(71)
Total Stockholders' Equity	4,515	4,506
Total Liabilities and Stockholders' Equity	$14,213	$13,221

See the notes to the consolidated financial statements

DYNEGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share data)

	Year Ended December 31, 2008	2007	2006
Revenues	$ 3,549	$ 3,103	$1,770
Cost of sales	(1,853)	(1,551)	(798)
Operating and maintenance expense, exclusive of depreciation shown separately below	(494)	(462)	(338)
Depreciation and amortization expense	(371)	(325)	(217)
Impairment and other charges	(47)	—	(119)
Gain on sale of assets, net	82	43	3
General and administrative expenses	(157)	(203)	(196)
Operating income	709	605	105
Losses from unconsolidated investments	(123)	(3)	(1)
Interest expense	(427)	(384)	(382)
Debt conversion costs	—	—	(249)
Other income and expense, net	84	56	54
Minority interest income (expense)	3	(7)	—
Income (loss) from continuing operations before income taxes	246	267	(473)
Income tax (expense) benefit	(75)	(151)	152
Income (loss) from continuing operations	171	116	(321)
Income (loss) from discontinued operations, net of tax (expense) benefit of $(1), $(91) and $10, respectively (Note 4)	3	148	(13)
Income (loss) before cumulative effect of change in accounting principles	174	264	(334)
Cumulative effect of change in accounting principles, net of tax benefit (expense) of zero, zero and zero, respectively (Note 2)	—	—	1
Net income (loss)	174	264	(333)
Less: preferred stock dividends (Note 16)	—	—	9
Net income (loss) applicable to common stockholders	$ 174	$ 264	$ (342)
Earnings (Loss) Per Share (Note 18):			
Basic earnings (loss) per share:			
Earnings (loss) from continuing operations	$ 0.20	$ 0.15	$ (0.72)
Income (loss) from discontinued operations	—	0.20	(0.03)
Cumulative effect of change in accounting principles	—	—	—
Basic earnings (loss) per share	$ 0.20	$ 0.35	$ (0.75)
Diluted earnings (loss) per share:			
Earnings (loss) from continuing operations	$ 0.20	$ 0.15	$ (0.72)
Income (loss) from discontinued operations	—	0.20	(0.03)
Cumulative effect of change in accounting principles	—	—	—
Diluted earnings (loss) per share	$ 0.20	$ 0.35	$ (0.75)
Basic shares outstanding	840	752	459
Diluted shares outstanding	842	754	509

See the notes to the consolidated financial statements

DYNEGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 174	$ 264	$ (333)
Adjustments to reconcile income (loss) to net cash flows from operating activities:			
Depreciation and amortization	376	333	265
Impairment and other charges	47	—	155
Losses from unconsolidated investments, net of cash distributions	124	3	1
Risk-management activities	(255)	(50)	(87)
Gain on sale of assets, net	(82)	(267)	(5)
Deferred taxes	73	215	(162)
Cumulative effect of change in accounting principles (Note 2)	—	—	(1)
Reserve for doubtful accounts	—	—	(35)
Legal and settlement charges	6	26	(2)
Sithe Subordinated Debt exchange charge (Note 12)	—	—	36
Debt conversion costs	—	—	249
Other	33	42	71
Changes in working capital:			
Accounts receivable	68	(114)	391
Inventory	3	(13)	8
Prepayments and other assets	(51)	(37)	126
Accounts payable and accrued liabilities	(71)	(15)	(885)
Changes in non-current assets	(113)	(57)	11
Changes in non-current liabilities	(13)	11	3
Net cash provided by (used in) operating activities	319	341	(194)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(611)	(379)	(155)
Unconsolidated investments	(6)	3	—
Proceeds from asset sales, net	451	558	227
Business acquisitions, net of cash acquired	—	(128)	(8)
Proceeds from exchange of unconsolidated investments, net of cash acquired (Note 3 and Note 4)	—	—	165
Increase in short-term investments	(27)	—	—
(Increase) decrease in restricted cash	80	(871)	121
Other investing, net	11	—	8
Net cash provided by (used in) investing activities	(102)	(817)	358
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	192	2,758	1,071
Repayments of borrowings	(45)	(2,320)	(1,930)
Debt conversion costs	—	—	(249)
Redemption of Series C Preferred (Note 16)	—	—	(400)
Net proceeds from issuance of capital stock	2	4	183
Dividends and other distributions, net	—	—	(17)
Other financing, net	(1)	(9)	—
Net cash provided by (used in) financing activities	148	433	(1,342)
Net increase (decrease) in cash and cash equivalents	365	(43)	(1,178)
Cash and cash equivalents, beginning of period	328	371	1,549
Cash and cash equivalents, end of period	$ 693	$ 328	$ 371

See the notes to the consolidated financial statements

DYNEGY INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(in millions)

	Common Stock	Additional Paid-In Capital	Subscriptions Receivable	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Treasury Stock	Total
December 31, 2005	$ 3,955	$ 51	$ (8)	$ 4	$(1,793)	$ (69)	$2,140
Net loss	—	—	—	—	(333)	—	(333)
Other comprehensive income, net of tax	—	—	—	98	—	—	98
Adjustment to initially apply SFAS No. 158, net of tax benefit of $21	—	—	—	(35)	—	—	(35)
Options exercised	5	(5)	—	—	—	—	—
Dividends and other distributions	—	—	—	—	(9)	—	(9)
401(k) plan and profit sharing stock	3	—	—	—	—	—	3
Options and restricted stock granted	—	8	—	—	—	—	8
Equity issuance (Note 20)	185	(7)	—	—	—	—	178
Equity conversion (Note 20)	225	(8)	—	—	—	—	217
December 31, 2006	$ 4,373	$ 39	$ (8)	$ 67	$(2,135)	$ (69)	$2,267
Net income	—	—	—	—	264	—	264
Other comprehensive loss, net of tax	—	—	—	(92)	—	—	(92)
Adjustment to initially apply FIN No. 48	—	—	—	—	7	—	7
Subscriptions receivable	—	—	3	—	—	—	3
Options exercised	1	2	—	—	—	(2)	1
401(k) plan and profit sharing stock	1	3	—	—	—	—	4
Options and restricted stock granted	—	19	—	—	—	—	19
Equity issuance-LS Power (Note 3)	3	2,030	—	—	—	—	2,033
Conversion from Illinois entity to Delaware entity (Note 20)	(4,370)	4,370	—	—	—	—	—
December 31, 2007	$ 8	$6,463	$ (5)	$ (25)	$(1,864)	$ (71)	$4,506
Net income	—	—	—	—	174	—	174
Other comprehensive loss, net of tax	—	—	—	(190)	—	—	(190)
Subscriptions receivable	—	—	3	—	—	—	3
Options exercised	—	2	—	—	—	—	2
401(k) plan and profit sharing stock	—	5	—	—	—	—	5
Options and restricted stock granted	—	15	—	—	—	—	15
December 31, 2008	$ 8	$6,485	$ (2)	$(215)	$(1,690)	$ (71)	$4,515

See the notes to the consolidated financial statements

DYNEGY INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in millions)

	Year Ended December 31, 2008	2007	2006
Net income (loss)	$ 174	$ 264	$(333)
Cash flow hedging activities, net:			
Unrealized mark-to-market gains (losses) arising during period, net	(142)	(95)	95
Reclassification of mark-to-market (gains) losses to earnings, net	10	(25)	(17)
Deferred losses on cash flow hedges, net	(4)	—	—
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $60, $69 and $(46), respectively)	(136)	(120)	78
Allocation to minority interest	50	5	—
Total cash flow hedging activities	(86)	(115)	78
Foreign currency translation adjustments	(27)	4	(1)
Minimum pension liability (net of tax expense $5)	—	—	10
Actuarial gain (loss) and amortization of unrecognized prior service cost (net of tax benefit (expense) of $29 and $(9), respectively)	(41)	18	—
Unrealized gain (loss) on securities, net:			
Unrealized gain (loss) on securities	(3)	6	11
Reclassification adjustments for gains realized in net income (loss)	(9)	(5)	—
Unrealized gains (losses) on securities, net (net of tax benefit (expense) of $8, $(1), and $(7), respectively)	(12)	1	11
Unconsolidated investment other comprehensive loss, net (net of tax benefit of $17)	(24)	—	—
Other comprehensive income (loss), net of tax	(190)	(92)	98
Comprehensive income (loss)	$ (16)	$ 172	$(235)

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.

CONSOLIDATED BALANCE SHEETS
(in millions)

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 670	$ 292
Restricted cash and investments	87	104
Short-term investments	24	—
Accounts receivable, net of allowance for doubtful accounts of $20 and $15, respectively	343	428
Accounts receivable, affiliates	1	1
Inventory	184	199
Assets from risk-management activities	1,263	358
Deferred income taxes	4	30
Prepayments and other current assets	204	145
Assets held for sale (Note 4)	—	57
Total Current Assets	2,780	1,614
Property, Plant and Equipment	10,869	10,689
Accumulated depreciation	(1,935)	(1,672)
Property, Plant and Equipment, Net	8,934	9,017
Other Assets		
Unconsolidated investments	—	18
Restricted cash and investments	1,158	1,221
Assets from risk-management activities	114	55
Goodwill	433	438
Intangible assets	437	497
Deferred income taxes	—	6
Accounts receivable, affiliates	4	—
Other long-term assets	314	241
Total Assets	$14,174	$13,107
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$ 284	$ 291
Accrued interest	56	56
Accrued liabilities and other current liabilities	157	202
Liabilities from risk-management activities	1,119	397
Notes payable and current portion of long-term debt	64	51
Deferred income taxes	1	—
Liabilities held for sale (Note 4)	—	2
Total Current Liabilities	1,681	999
Long-term debt	5,872	5,739
Long-term debt to affiliates	200	200
Long-Term Debt	6,072	5,939
Other Liabilities		
Liabilities from risk-management activities	288	116
Deferred income taxes	1,052	1,052
Other long-term liabilities	498	381
Total Liabilities	9,591	8,487
Minority Interest	(30)	23
Commitments and Contingencies (Note 19)		
Stockholder's Equity		
Capital Stock, $1 par value, 1,000 shares authorized at December 31, 2008 and December 31, 2007, respectively	—	—
Additional paid-in capital	5,684	5,684
Affiliate receivable	(827)	(825)
Accumulated other comprehensive loss, net of tax	(215)	(25)
Accumulated deficit	(29)	(237)
Total Stockholder's Equity	4,613	4,597
Total Liabilities and Stockholder's Equity	$14,174	$13,107

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Year Ended December 31,		
	2008	2007	2006
Revenues	$ 3,549	$ 3,103	$1,770
Cost of sales	(1,853)	(1,551)	(798)
Operating and maintenance expense, exclusive of depreciation shown separately below	(494)	(462)	(338)
Depreciation and amortization expense	(371)	(325)	(217)
Impairment and other charges	(47)	—	(119)
Gain on sale of assets	82	43	3
General and administrative expenses	(157)	(184)	(193)
Operating income	709	624	108
Earnings (losses) from unconsolidated investments	(40)	6	(1)
Interest expense	(427)	(384)	(375)
Debt conversion costs	—	—	(204)
Other income and expense, net	83	53	51
Minority interest income (expense)	3	(7)	—
Income (loss) from continuing operations before income taxes	328	292	(421)
Income tax (expense) benefit	(123)	(116)	125
Income (loss) from continuing operations	205	176	(296)
Income (loss) from discontinued operations, net of tax (expense) benefit of $(1), $(92) and $12, respectively (Note 4)	3	148	(12)
Net income (loss)	$ 208	$ 324	$ (308)

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 208	$ 324	$ (308)
Adjustments to reconcile income (loss) to net cash flows from operating activities:			
Depreciation and amortization	376	333	263
Impairment and other charges	47	—	155
(Earnings) losses from unconsolidated investments, net of cash distributions	41	(6)	1
Risk-management activities	(255)	(50)	(87)
Gain on sale of assets, net	(82)	(267)	(5)
Deferred taxes	119	179	(138)
Reserve for doubtful accounts	—	—	(35)
Legal and settlement charges	6	26	(2)
Sithe Subordinated Debt exchange charge (Note 15)	—	—	36
Debt conversion costs	—	—	204
Other	29	39	69
Changes in working capital:			
Accounts receivable	67	(114)	391
Inventory	3	(13)	8
Prepayments and other assets	(51)	(37)	102
Accounts payable and accrued liabilities	(67)	(1)	(873)
Changes in non-current assets	(108)	(56)	11
Changes in non-current liabilities	(14)	11	3
Net cash provided by (used in) operating activities	319	368	(205)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(611)	(379)	(155)
Proceeds from asset sales, net	451	558	224
Unconsolidated investments	10	13	—
Business acquisitions, net of cash acquired	—	16	—
Proceeds from exchange of unconsolidated investments, net of cash acquired (Note 3 and Note 4)	—	—	165
Increase in short-term investments	(25)	—	—
(Increase) decrease in restricted cash	80	(871)	121
Affiliate transactions	1	(24)	(6)
Other investing, net	7	(1)	8
Net cash provided by (used in) investing activities	(87)	(688)	357
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	192	2,758	1,071
Repayments of borrowings	(45)	(2,045)	(1,930)
Borrowings from (repayments to) affiliate, net	—	—	(120)
Debt conversion costs	—	—	(204)
Dividends to affiliates	—	(342)	(50)
Other financing, net	(1)	(2)	(2)
Net cash provided by (used in) financing activities	146	369	(1,235)
Net increase (decrease) in cash and cash equivalents	378	49	(1,083)
Cash and cash equivalents, beginning of period	292	243	1,326
Cash and cash equivalents, end of period	$ 670	$ 292	$ 243

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDER'S EQUITY
(in millions)

	Additional Paid-In Capital	Affiliate Receivable	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total
December 31, 2005	$3,593	$ —	$ 4	$(266)	$3,331
Net loss	—	—	—	(308)	(308)
Other comprehensive income, net of tax	—	—	98	—	98
Adjustment to initially apply SFAS No. 158, net of tax benefit of $21	—	—	(35)	—	(35)
Dividends to affiliates	(50)	—	—	—	(50)
December 31, 2006	$3,543	$ —	$ 67	$(574)	$3,036
Net income	—	—	—	324	324
Other comprehensive loss, net of tax	—	—	(92)	—	(92)
Adjustment to initially apply FIN No. 48	—	—	—	13	13
Contribution of Contributed Entities and Sandy Creek to DHI	2,483	—	—	—	2,483
Reclassification of affiliate receivable	—	(825)	—	—	(825)
Dividends to affiliates	(342)	—	—	—	(342)
December 31, 2007	$5,684	$(825)	$ (25)	$(237)	$4,597
Net income	—	—	—	208	208
Other comprehensive loss, net of tax	—	—	(190)	—	(190)
Affiliate activity	—	(2)	—	—	(2)
December 31, 2008	$5,684	$(827)	$(215)	$ (29)	$4,613

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in millions)

	Year Ended December 31,		
	2008	2007	2006
Net income (loss)	$ 208	$ 324	$(308)
Cash flow hedging activities, net:			
Unrealized mark-to-market gains (losses) arising during period, net	(142)	(95)	95
Reclassification of mark-to-market (gains) losses to earnings, net	10	(25)	(17)
Deferred losses on cash flow hedges, net	(4)	—	—
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $60, $69 and $(46), respectively)	(136)	(120)	78
Allocation to minority interest	50	5	—
Total cash flow hedging activities	(86)	(115)	78
Foreign currency translation adjustments	(27)	4	(1)
Minimum pension liability (net of tax expense of $5)	—	—	10
Actuarial gain (loss) and amortization of unrecognized prior service cost (net of tax benefit (expense) of $29 and $(9), respectively)	(41)	18	—
Unrealized gain (loss) on securities, net:			
Unrealized gain (loss) on securities	(3)	6	11
Reclassification adjustments for gains realized in net income (loss)	(9)	(5)	—
Unrealized losses on securities, net (net of tax benefit (expense) of $8, $(1), and $(7), respectively)	(12)	1	11
Unconsolidated investment other comprehensive loss, net (net of tax benefit of $17)	(24)	—	—
Other comprehensive income (loss), net of tax	(190)	(92)	98
Comprehensive income (loss)	$ 18	$ 232	$(210)

See the notes to the consolidated financial statements

DYNEGY INC. and DYNEGY HOLDINGS INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Operations

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) the Midwest segment ("GEN-MW"), (ii) the West segment ("GEN-WE"), and (iii) the Northeast segment ("GEN-NE"). Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization.

In addition to our operating generation facilities, we own an approximate 37 percent interest in PPEA Holding Company LLC ("PPEA") which in turn owns an approximate 57 percent undivided interest in Plum Point Energy Associates, LLC ("Plum Point"), a 665 MW coal-fired power generation facility (the "Plum Point Project") under construction in Arkansas, which is included in GEN-MW. We also own a 50 percent interest in Sandy Creek Holdings, LLC ("SCH"), which through a subsidiary owns an approximate 64 percent undivided interest in Sandy Creek Energy Station ("the Sandy Creek Project"), an 898 MW coal-fired power generation facility under construction in McLennan County, Texas, which is included in GEN-WE.

Note 2—Summary of Significant Accounting Policies

Use of Estimates. The preparation of consolidated financial statements in conformity with generally accepted accounting principles ("GAAP") requires management to make informed estimates and judgments that affect our reported financial position and results of operations based on currently available information. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (i) developing fair value assumptions, including estimates of future cash flows and discount rates, (ii) analyzing tangible and intangible assets for possible impairment, (iii) estimating the useful lives of our assets, (iv) assessing future tax exposure and the realization of deferred tax assets, (v) determining amounts to accrue for contingencies, guarantees and indemnifications, (vi) estimating various factors used to value our pension assets and liabilities and (vii) determining the primary beneficiary of variable interest entities ("VIEs"). Actual results could differ materially from our estimates.

Principles of Consolidation. The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries and VIEs for which we are the primary beneficiary and our proportionate share of assets, liabilities and expenses directly related to an undivided interest in Plum Point. Intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to prior-period amounts to conform with current-period presentation.

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

Restricted Cash and Investments. Restricted cash and investments represent cash that is not readily available for general purpose cash needs. Restricted cash and investments are classified as a current or long-term asset based on the timing and nature of when or how the cash is expected to be used or when the restrictions are expected to lapse. We include all changes in restricted cash and investments in investing cash flows on the consolidated statements of cash flows. Please read Note 15—Debt—Restricted Cash and Investments for further discussion.

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

Unconsolidated Investments. We use the equity method of accounting for investments in affiliates over which we exercise significant influence, generally occurring in ownership interests of 20 percent to 50 percent, and also occurring in lesser ownership percentages due to voting rights or other factors and VIEs where we are not the primary beneficiary. Our share of net income (loss) from these affiliates is reflected in the consolidated statements of operations as earnings (losses) from unconsolidated investments. Any excess of our investment in affiliates, as compared to our share of the underlying equity that is not recognized as goodwill, that represents identifiable other intangible assets, is amortized over the estimated economic service lives of the underlying assets. Or, in the instances where the useful lives can not be determined, the excess is assessed each reporting period for impairment or to determine if the useful life can be estimated. All investments in unconsolidated affiliates are periodically assessed for other-than-temporary declines in value, with write-downs recognized in earnings from unconsolidated investments in the consolidated statements of operations. When the carrying amount of an equity investment has been reduced below zero and we have a funding commitment, the negative investment balance is included in Other long-term liabilities on the consolidated balance sheets.

Please read Note 5—Impairment Charges for a discussion of impairment charges we recognized in 2008 and 2006.

Available-for-Sale Securities. For securities classified as available-for-sale that have readily determinable fair values, the change in the unrealized gain or loss, net of deferred income tax, is recorded as a separate component of accumulated other comprehensive income (loss) in the consolidated statements of comprehensive income (loss). Realized gains and losses on investment transactions are determined using the specific identification method.

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

In accordance with EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty", we account for exchanges of inventory with the same counterparty as one transaction at fair value.

We may opportunistically sell emissions allowances, subject to certain regulatory limitations and restrictions contained in our Consent Decree, or hold them in inventory until they are needed. In the past, we have sold emission allowances that relate to future periods. To the extent the proceeds received from the sale of such allowances exceed our cost, we defer the associated gain until the period to which the allowance relates, as we may be required to purchase emissions allowances in future periods. As of December 31, 2008 and 2007, we had aggregate deferred gains of $9 million, all of which is included in Other long-term liabilities on the consolidated balance sheets. We recognized $32 million, $13 million and $16 million in revenue for the years ended December 31, 2008, 2007 and 2006, respectively, related to sales of emissions credits.

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

Asset Group	Range of Years
Power generation facilities	20 to 40
Buildings and improvements	10 to 39
Office and miscellaneous equipment	3 to 20

Gains and losses on sales of individual assets or asset groups are reflected in Gain on sale of assets, net, in the consolidated statements of operations. We assess the carrying value of our property, plant and equipment in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS No. 144"). If an impairment is indicated, the amount of the impairment loss recognized would be determined by the amount by which 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.

Please read Note 5—Impairment Charges for a discussion of impairment charges we recognized in 2008 and 2006.

Goodwill and Other Intangible Assets. Goodwill represents, at the time of an acquisition, the amount of purchase price paid in excess of the fair value of net assets acquired. We follow the guidance set forth in SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS No. 142"), when assessing the carrying value of our goodwill for impairment. Accordingly, we evaluate our goodwill for impairment on an annual basis on November 1st, and when events warrant an assessment. Our evaluation is based, in part, on our estimate of future cash flows and recent market comparable transactions. The estimation of fair value is highly subjective, inherently imprecise and can change materially from period to period based on, among other things, an assessment of market conditions, projected cash flows and discount rates. We have completed our goodwill impairment analysis for 2008 and no impairment was indicated. Please read Note 13—Goodwill for further discussion of our impairment analysis.

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

In accordance with SFAS No. 142, we initially record and measure intangible assets based on the fair value of those rights transferred in the transaction in which the asset was acquired. Those measurements are based on quoted market prices for the asset, if available, or measurement techniques based on the best information available such as a present value of future cash flows. Present value measurement techniques involve judgments and estimates made by management about prices, cash flows, discount factors and other variables, and the actual value realized from those assets could vary materially from these judgments and estimates. We amortize our definite-lived intangible assets based on the useful life of the respective asset as measured by the life of the underlying contract or contracts. Intangible assets that are not subject to amortization are subjected to impairment testing on an annual basis or when a triggering event occurs, and an impairment loss is recognized if the carrying amount of an intangible asset exceeds its fair value.

Asset Retirement Obligations. We record the present value of our legal obligations to retire tangible, long-lived assets on our balance sheets as liabilities when the liability is incurred. Significant judgment is involved in estimating future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. Our AROs relate to activities such as ash pond and landfill capping, dismantlement of power generation facilities, future removal of asbestos containing material from certain power generation facilities, closure and post-closure costs, environmental testing, remediation, monitoring and land and equipment lease obligations. A summary of changes in our AROs is as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Beginning of year	$107	$ 56	$ 56
New AROs (1)	—	—	6
Accretion expense	10	8	6
Acquisition of the Contributed Entities	—	43	—
Revision of previous estimate (2)	10	—	(12)
End of year	$127	$107	$ 56

(1) During 2006, we recorded additional AROs in the amount of $6 million related to our obligation to remediate a landfill located at our Danskammer generating facility. There were no additional AROs, other than those acquired from LS Contributed Entities, recorded or settled during 2008, 2007 or 2006.

(2) During 2008, we revised our ARO obligation upward by $10 million based on revised estimates of the cost to dismantle the South Bay facility. During 2006, we revised our ARO obligation downward by $12 million based on revised estimates of the costs to remediate ash ponds at certain of our coal fired generating facilities.

We may have additional potential retirement obligations for dismantlement of power generation facilities. Our current intent is to maintain these facilities in a manner such that they will be operated indefinitely. As a result, we cannot estimate any potential retirement obligations associated with these assets. Liabilities will be recorded in accordance with SFAS No. 143 at the time we are able to estimate these AROs.

Contingencies, Commitments, 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 judgment could change based on new information, changes in laws or regulations, changes in management's plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from these estimates and judgments.

Liabilities for environmental contingencies are recorded when 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.

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

Revenue Recognition. We earn revenue from our facilities in three primary ways: (i) sale of energy generated by our facilities; (i) 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 forward contracts, which commit us to sell commodities in the future; futures contracts, which are generally exchange-traded standard commitments to purchase or sell a commodity; option contracts, which convey the right to buy or sell a commodity; and swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined quantity. 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 specified 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.

Previously, we designated many commodity contracts that met the definition of a derivative as cash flow hedges. Beginning on April 2, 2007, we chose to cease designating such contracts as cash flow hedges, and thus have applied mark-to-market accounting treatment prospectively.

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. As of December 31, 2008, included in Prepayments and other current assets on our consolidated balance sheets, we had approximately $88 million of cash collateral postings, which represent the effect of net cash outflows arising from the daily settlements of our exchange-traded or brokered commodity futures positions held with our futures clearing manager.

Derivative Instruments-Financing Activities. We are exposed to changes in interest rates through our variable and fixed rate debt. In order to manage our interest rate risk, we enter into interest rate swap agreements.

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

Fair Value Measurements. On January 1, 2008, we adopted SFAS No. 157 , "Fair Value Measurements" ("SFAS No. 157") for financial assets and Liabilities. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosure requirements for fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, SFAS No. 157 does not require any new fair value measurements; however, for some entities the application of SFAS No. 157 will change current practice. The provisions of SFAS No. 157 are to be applied prospectively, except for the initial impact on three specific items: (i) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF No. 02-3, (ii) existing hybrid financial instruments measured initially at fair value using the transaction price and (iii) blockage factor discounts. We did not record a cumulative effect upon the adoption.

FASB Staff Position No. FAS 157-2 defers the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008, with respect to non-financial assets and non-financial liabilities which are not recognized or disclosed at fair value in the financial statements on a recurring basis. Therefore, we have deferred application of SFAS No. 157 to such non-financial assets and non-financial liabilities until January 1, 2009.

On October 10, 2008, the FASB issued Staff Position No. FAS 157-3 ("FSP SFAS No. 157-3"). FSP SFAS No. 157-3 clarifies the application of SFAS No. 157 to a financial asset when the market for that financial asset is not active. FSP SFAS No. 157-3 was effective upon issuance by the FASB. The issuance of FSP SFAS No. 157-3 had no impact on our financial statements.

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, our estimate of fair value reflects 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 exchange-traded derivatives, listed equities and U.S. government treasury securities.

- 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 as well as financial transmission rights. 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.

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.

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 benefit (expense) and net income (loss) in the period in which such a determination is made.

On January 1, 2007, we adopted FIN No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN No. 48"), which provides clarification of SFAS No. 109 with respect to the recognition of income tax benefits of uncertain tax positions in the financial statements. We recognize accrued interest expense and penalties related to unrecognized tax benefits as income tax expense.

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

Earnings Per Share. Basic earnings per share represent the amount of earnings for the period available to each share of common stock outstanding during the period. Diluted earnings per share amounts include the effect of issuing shares of common stock for outstanding stock options and performance based stock awards under the treasury stock method if including such potential common shares is dilutive.

Foreign Currency. For subsidiaries whose functional currency is not the U.S. Dollar, assets and liabilities are translated at year-end exchange rates, and revenues and expenses are translated at monthly average exchange rates. Translation adjustments for the asset and liability accounts are included as a separate component of accumulated other comprehensive loss in stockholders' equity. Currency transaction gains and losses are recorded in Other income and expense, net, in the consolidated statements of operations. We recorded gains (losses) of approximately \$24 million, \$(6) million and \$1 million for the years ended December 31, 2008, 2007 and 2006, respectively. In 2008, upon substantial liquidation of a foreign entity, we recognized approximately \$24 million of pre-tax income related to translation gains.

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

In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment" ("SFAS No. 123(R)") which revises SFAS No. 123. SFAS No. 123(R) requires all companies to expense the fair value of employee stock options and other forms of stock-based compensation. We adopted SFAS No. 123(R) effective January 1, 2006, using the modified prospective transition method permitted under this pronouncement. Our cumulative effect of implementing this standard, which consists entirely of a forfeiture adjustment, was less than $1 million after tax.

In November 2005, the FASB issued FSP No. 123(R)-3, "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards". We have adopted the short-cut method to calculate the beginning balance of the APIC pool of the excess tax benefit, and to determine the subsequent impact on the APIC pool and consolidated statements of cash flows of the tax effects of employee stock-based compensation awards that were outstanding upon our adoption of FAS 123(R). Utilizing the short-cut method, we have determined that we have a "Pool of Windfall" tax benefits that can be utilized to offset future shortfalls that may be incurred.

Please read Note 20—Capital Stock for further discussion of our share-based compensation and expense recognized for 2008, 2007 and 2006.

Minority Interest. Minority interest on the consolidated balance sheets includes third party investments in entities that we consolidate, but do not wholly own. The net pre-tax results attributed to minority interest holders in consolidated entities are included in Minority interest income (expense) in the consolidated statements of operations. The net after-tax other comprehensive income amounts attributed to minority interest holders in consolidated entities are included in the consolidated statements of comprehensive income (loss).

We allocate net income and other comprehensive income to minority interest owners in PPEA based on the amounts that would be distributed to the equity interest owners in accordance with the terms of the underlying agreement. To the extent that the losses applicable to the minority interest owners would cause the minority interest owners to exceed their obligation to make good such losses, the amounts are reallocated back to us. For the years ended December 31, 2008 and 2007, we have absorbed approximately $6 million and $1 million, respectively, of losses related to net income and approximately $114 million and $15 million, respectively, of losses related to other comprehensive income in excess of the minority interest holders' funding commitments. Beginning January 1, 2009, upon our adoption of FAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51" ("SFAS No. 160"), the noncontrolling interest holders will be allocated their losses, irrespective of their funding commitments. In addition, the presentation of minority interest on the consolidated balance sheets and consolidated statements of operations will change.

Accounting Principles Adopted

SFAS No. 157. On January 1, 2008, we adopted portions of SFAS No. 157. Please read Note 6—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

SFAS No. 159. On January 1, 2008, we adopted SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159"). SFAS No. 159 permits entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. We have not elected the fair value option to measure eligible items. Accordingly, this statement had no impact on our consolidated financial statements.

SFAS No. 162. On May 9, 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles" ("SFAS No. 162"). SFAS No. 162 is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. Prior to the issuance of SFAS No. 162, GAAP hierarchy was defined in the American Institute of Certified Public Accountants ("AICPA") Statement on Auditing Standards No. 69, "The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles" ("SAS No. 69"). SAS No. 69 has been criticized because it is directed to external auditors rather than the entity. SFAS No. 162 addresses these issues by establishing that the GAAP hierarchy should be directed to entities because it is the entity (not its auditor) that is responsible for selecting accounting principles for financial statements that are presented in conformity with GAAP. SFAS No. 162 was effective on November 15, 2008. This statement had no impact on our consolidated financial statements.

Accounting Principles Not Yet Adopted

SFAS No. 141(R). On December 4, 2007, the FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141(R)"). SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS No. 141(R) is effective for fiscal years beginning on or after December 15, 2008. We will apply SFAS No. 141(R) for any business combinations that may be entered into after January 1, 2009.

SFAS No. 160. On December 4, 2007, the FASB issued SFAS No. 160. SFAS No. 160 requires ownership interests in subsidiaries held by parties other than the parent be clearly identified, labeled, and presented in the consolidated statement of financial position within equity, but separate from the parent's equity; the amount of consolidated net income attributable to the parent and to the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of income; changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently; and any retained noncontrolling equity investment in the former subsidiary be initially measured at fair value. SFAS No. 160 also requires that noncontrolling interest holders continue to be attributed their share of losses even if these attributions result in a deficit noncontrolling interest balance. SFAS No. 160 is effective for fiscal years beginning on or after December 15, 2008. Please read Note 2—Summary of Significant Accounting Policies—Minority Interest for further discussion.

SFAS No. 161. On March 19, 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities" ("SFAS No. 161"). SFAS No. 161 is meant to improve transparency about the location and amounts of derivative instruments in an entity's financial statements; how derivative instruments and related hedged items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended; and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS No. 161 requires disclosure of the fair values of derivative instruments and their gains and losses in a tabular format. It also provides more information about an entity's liquidity by requiring disclosure of derivative features that are credit risk-related and it requires cross-referencing within footnotes to enable financial statement users to locate important information about derivative instruments. SFAS No. 161 is effective for fiscal years beginning on or after November 15, 2008. We are currently evaluating the disclosure implications of this standard, however, this statement will have no impact on our financial condition, results of operations or cash flows.

EITF 08-5. On September 24, 2008, EITF Issue No. 08-5, "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF No. 08-5) was issued. EITF 08-5 addresses fair value measurement for liabilities issued with an inseparable third-party credit enhancement. EITF No. 08-5 concludes that the issuer of a liability with a third-party credit enhancement should not include the effect of the credit enhancement in the fair value measurements of the liability. EITF No. 08-5 is effective for periods beginning on or after December 15, 2008. EITF No. 08-5 provides additional guidance with respect to the manner in which we consider credit enhancements, such as letters of credit, in valuing our derivative liability positions under SFAS No. 157. We are currently evaluating the impact of this EITF on our consolidated financial statements.

Note 3—Business Combinations and Acquisitions

LS Power Business Combination. On March 29, 2007, at a special meeting of the shareholders of Dynegy Illinois Inc. ("Dynegy Illinois"), the shareholders of Dynegy Illinois (i) adopted the Plan of Merger, Contribution and Sale Agreement, dated as of September 14, 2006 (the "Merger Agreement"), by and among Dynegy, Dynegy Illinois, Falcon Merger Sub Co., an Illinois corporation and a then-wholly owned subsidiary of Dynegy ("Merger Sub"), 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 Contributing Entities") and (ii) approved the merger of Merger Sub with and into Dynegy Illinois (together with the Merger Agreement, the "Merger").

Upon the closing of the Merger, Dynegy Illinois became a wholly owned subsidiary of Dynegy and each share of the Class A common stock and Class B common stock of Dynegy Illinois outstanding immediately prior to the Merger was converted into the right to receive one share of the Class A common stock of Dynegy, and the LS Contributing Entities transferred to Dynegy all of the interests owned by them in entities that own eleven power generation facilities (the "Contributed Entities").

As part of the Merger transactions, LS Associates transferred its interests in certain power generation development projects to DLS Power Holdings, and contributed 50 percent of the membership interests in DLS Power Holdings to Dynegy. In addition, immediately after the completion of the Merger, LS Associates and Dynegy each contributed $5 million to DLS Power Holdings as their initial capital contributions, and also contributed their respective interests in certain additional power generation development projects to DLS Power Holdings. In connection with the formation of DLS Power Holdings, LS Associates formed DLS Power Development Company, LLC, a Delaware limited liability company ("DLS Power Development"). LS Associates and Dynegy each now own 50 percent of the membership interests in DLS Power Development. Please read Note 12—Variable Interest Entities—DLS Power Holdings and DLS Power Development for a discussion of our dissolution of these entities.

The aggregate purchase price was comprised of (i) $100 million cash, (ii) 340 million shares of the Class B common stock of Dynegy, (iii) the issuance of a promissory note in the aggregate principal amount of $275 million (the "Note") (which was simultaneously issued and repaid in full without interest or prepayment penalty), (iv) the issuance of an additional $70 million of project-related debt (the "Griffith Debt") (which was simultaneously issued and repaid in full without interest or prepayment penalty) via an indirect wholly owned subsidiary, and (v) transaction costs of approximately $52 million, approximately $8 million of which were paid in 2006. The Class B common stock issued by Dynegy was valued at $5.98 per share, which represents the average closing price of Dynegy's common stock on the New York Stock Exchange for the two days prior to, including, and two days subsequent to the September 15, 2006 public announcement of the Merger, or approximately $2,033 million. Dynegy funded the cash payment and the repayment of the Note and the Griffith Debt using cash on hand and borrowings by DHI (and subsequent permitted distributions to Dynegy) of (i) an aggregate $275 million under the Revolving Facility (as defined below) and (ii) an aggregate $70 million under the new Term Loan B (as defined below). Please read Note 15—Debt—Fifth Amended and Restated Credit Facility for further discussion. We paid a premium over the fair value of the net tangible and identified intangible assets acquired due to the (i) scale and diversity of assets acquired in key regions of the United States; (ii) financial stability, and (iii) proven nature of the LS Power asset development platform that was subsequently contributed to DLS Power Holdings and DLS Power Development.

The application of purchase accounting under SFAS No. 141 requires that the total purchase price be allocated to the fair value of assets acquired and liabilities assumed based on their fair values at the acquisition date, with amounts exceeding the fair values being recorded as goodwill in accordance with SFAS No. 142. The allocation process requires an analysis of acquired fixed assets, contracts, and contingencies to identify and record the fair value of all assets acquired and liabilities assumed. Dynegy's allocation of the purchase price to specific assets and liabilities was based upon customary valuation procedures and techniques.

The following table summarizes the fair values of the assets acquired and liabilities assumed at the date of acquisition (in millions):

Cash	$ 16
Restricted cash and investments (including $37 million current)	91
Accounts receivable	52
Inventory	37
Assets from risk management activities (including $11 million current)	37
Prepaids and other current assets	12
Property, plant and equipment	4,223
Intangible assets (including $9 million current)	224
Goodwill	486
Unconsolidated investments	83
Other	35
Total assets acquired	$ 5,296
Current liabilities and accrued liabilities	$ (92)
Liabilities from risk management activities (including $14 million current)	(75)
Long-term debt (including $32 million current)	(1,898)
Deferred income taxes	(627)
Other	(96)
Minority interest	22
Total liabilities and minority interest assumed	$(2,766)
Net assets acquired	$ 2,530

As noted above, Dynegy recorded goodwill of approximately $486 million. Of the goodwill recorded, $81 million was assigned to the GEN-MW reporting unit, $308 million was assigned to the GEN-WE reporting unit and $97 million was assigned to the GEN-NE reporting unit. Please read Note 13—Goodwill for further discussion of goodwill.

Dynegy recorded net intangible assets of $185 million. This consisted of intangible assets of $192 million in GEN-MW and $32 million in GEN-WE offset by intangible liabilities of $4 million and $35 million, respectively, in GEN-NE and GEN-MW. Please read Note 14—Intangible Assets—LS Power for further discussion of the intangible assets.

The intangible liability of $35 million in GEN-MW primarily related to a contract held by LSP Kendall Holding LLC, one of the entities transferred to Dynegy, and ultimately DHI, by the LS Contributing Entities.

LSP Kendall Holding LLC was party to a power tolling agreement with another of our subsidiaries. This power tolling agreement had a fair value of approximately $31 million as of April 2, 2007, representing a liability from the perspective of LSP Kendall Holding LLC. Upon completion of the Merger, this power tolling agreement was effectively settled, which resulted in a second quarter 2007 gain equal to the fair value of this contract, in accordance with EITF Issue 04-01, "Accounting for Pre-existing Contractual Relationships Between the Parties to a Purchase Business Combination" ("EITF Issue 04-1"). We recorded a second quarter 2007 pre-tax gain of approximately $31 million, included as a reduction to Cost of sales on the consolidated statements of operations.

The differences between the financial and tax bases of purchased intangibles and goodwill are not deductible for tax purposes. However, purchase accounting allows for the establishment of deferred tax liabilities on purchased intangibles (other than goodwill) that will be reflected as a tax benefit on our future consolidated statements of operations in proportion to and over the amortization period of the related intangible asset.

Dynegy's results of operations include the results of the acquired entities for the period beginning April 2, 2007. The following table presents unaudited pro forma information for 2007 and 2006 as if the acquisition had occurred on January 1, 2007 or 2006, respectively:

	Twelve Months Ended December 31, 2007		Twelve Months Ended December 31, 2006	
	Actual	Pro Forma (Unaudited)	Actual	Pro Forma (Unaudited)
	(in millions)			
Revenue	$3,103	$3,392	$1,770	$2,739
Income (loss) before cumulative effect of change in accounting principal	264	216	(334)	(354)
Net income (loss) applicable to common stockholders	264	216	(342)	(362)
Basic earnings (loss) per share before cumulative effect of accounting change	$ 0.35	$ 0.29	$ (0.75)	$ (0.45)
Diluted earnings (loss) per share before cumulative effect of accounting change	0.35	0.29	(0.75)	(0.45)
Basic earnings (loss) per share	0.35	0.29	(0.75)	(0.45)
Diluted earnings (loss) per share	0.35	0.29	(0.75)	(0.45)

These unaudited pro forma results, based on assumptions deemed appropriate by management, have been prepared for informational purposes only and are not necessarily indicative of Dynegy's results if the Merger had occurred on January 1, 2007 or 2006, respectively, for the years ended December 31, 2007 and 2006. Pro forma adjustments to the results of operations include the effects on depreciation and amortization, interest expense, interest income and income taxes. The unaudited pro forma condensed consolidated financial statements reflect the Merger in accordance with SFAS No. 141 and SFAS No. 142.

The consummation of the Merger constituted a change in control as defined in our severance pay plans, as well as the various long-term incentive award grant agreements. As a result, all outstanding restricted stock and stock option awards previously granted to employees vested in full on April 2, 2007 upon the closing of the Merger. Specifically, the vesting of the restricted stock awards granted in 2005 and 2006 and the unvested tranches of stock option awards granted in those years were accelerated. Accordingly, we recorded a charge of approximately $6 million in 2007, included in General and administrative expense on our consolidated statement of operations.

LS Assets Contribution. In April 2007, in connection with the completion of the Merger, Dynegy contributed to Dynegy Illinois its interest in the Contributed Entities. Following such contribution, Dynegy Illinois contributed to DHI its interest in the Contributed Entities and, as a result, the Contributed Entities are subsidiaries of DHI. Accordingly, all of the entities acquired in the Merger are included within DHI with the exception of Dynegy's 50 percent interests in DLS Power Holdings and DLS Power Development, which are directly owned by Dynegy.

DHI's results of operations include the results of the acquired entities for the period beginning April 2, 2007. The following table presents unaudited pro forma information for 2007 and 2006, as if the acquisition and subsequent contribution had occurred on January 1, 2007 or 2006, respectively:

	Twelve Months Ended December 31, 2007		Twelve Months Ended December 31, 2006	
	Actual	Pro Forma (Unaudited)	Actual	Pro Forma (Unaudited)
	(in millions)			
Revenue	$3,103	$3,392	$1,770	$2,739
Net income (loss)	324	279	(308)	(319)

These unaudited pro forma results, based on assumptions deemed appropriate by management, have been prepared for informational purposes only and are not necessarily indicative of DHI's results if the Merger had occurred on January 1, 2007 and 2006, respectively, for the twelve months ended December 31, 2007 and 2006. Pro forma adjustments to the results of operations include the effects on depreciation and amortization, interest expense, interest income and income taxes. The unaudited pro forma condensed consolidated financial statements reflect the Merger in accordance with SFAS No. 141 and SFAS No. 142.

Sithe Assets Contribution. In April 2007, Dynegy Illinois contributed to DHI all of its interest in New York Holdings, together with its indirect interest in the subsidiaries of New York Holdings. New York Holdings, together with its wholly owned subsidiaries, owns the Sithe Assets. The Sithe Assets primarily consist of the Independence power generation facility. This contribution was accounted for as a transaction between entities under common control. As such, the assets and liabilities of New York Holdings 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 New York Holdings beginning January 31, 2005.

Rocky Road. On March 31, 2006, contemporaneous with our sale of our interest in WCP (Generation) Holdings LLC ("West Coast Power"), we completed our acquisition of NRG's 50 percent ownership interest in Rocky Road Power, LLC ("Rocky Road"), the entity that owns the Rocky Road power plant, a 330-megawatt natural gas-fired peaking facility near Chicago (of which we already owned 50 percent). As a result of the two transactions, we received net proceeds of $165 million, net of cash acquired. In addition, we became the primary beneficiary of the entity as provided under the guidance in FIN No. 46 (R), and thus consolidated the assets and liabilities of the entity at March 31, 2006. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—West Coast Power and Note 11—Unconsolidated Investments for further discussion.

Note 4—Dispositions, Contract Terminations and Discontinued Operations

Dispositions and Contract Terminations

Heard County. On February 25, 2009, we entered into an agreement to sell our interest in the Heard County power generation facility to Oglethorpe Power Corporation ("Oglethorpe") for approximately $105 million, subject to regulatory approval. The transaction is expected to close in the first half of 2009. We recorded a pre-tax impairment of approximately $47 million in the year ended December 31, 2008, which was included in

Impairment and other charges on our consolidated statements of operations. Please read Note 5—Impairment Charges—Asset Impairments for further discussion. We expect to record an estimated $10 million gain related to the sale of the asset when the sale closes.

Rolling Hills. On July 31, 2008, we completed the sale of the Rolling Hills power generation facility ("Rolling Hills") to an affiliate of Tenaska Capital Management, LLC for approximately $368 million, net of transaction costs. We recorded a $56 million gain during 2008 related to the sale, which is included in Gain on sale of assets in our consolidated statements of operations. The gain includes the impact of allocating approximately $5 million of goodwill associated with the GEN-MW reporting unit to Rolling Hills. The amount of goodwill allocated to Rolling Hills was based on the relative fair values of Rolling Hills and the portion of the GEN-MW reporting unit being retained.

In accordance with SFAS No. 144, we discontinued depreciation and amortization of Rolling Hills' property, plant and equipment during the second quarter 2008. Depreciation and amortization expense related to Rolling Hills totaled $3 million, $8 million and $8 million in the years ended December 31, 2008, 2007 and 2006, respectively. The sale of Rolling Hills did not meet the definition of a discontinued operation. As such, we are reporting the results of Rolling Hills' operations in continuing operations.

The sale of Rolling Hills represented the sale of a significant portion of a reporting unit. As a result, in accordance with SFAS No. 142, we assessed the goodwill of the GEN-MW reporting unit for impairment during the third quarter 2008. No impairment was indicated as a result of this assessment.

NYMEX Securities. In November 2006, the New York Mercantile Exchange ("NYMEX") completed its initial public offering. At the time, we had two membership seats on the NYMEX, and therefore, we received 90,000 NYMEX shares for each membership seat. During August 2007, we sold 30,000 shares for approximately $4 million, and we recognized a gain of $4 million. During the second quarter 2008, we sold our remaining 150,000 shares and both of our membership seats for approximately $16 million, and we recognized a gain of $15 million, which is included in Gain on sale of assets in our consolidated statements of operations partially offset by a reduction of $8 million, net of tax of $5 million, in our consolidated statements of other comprehensive income (loss).

Oyster Creek. In May 2008, we sold the beneficial interest in Oyster Creek Limited for approximately $11 million, which is included in Gain on sale of assets in our consolidated statements of operations.

PPEA Holding Company LLC. On December 13, 2007, we sold a non-controlling ownership interest in PPEA to certain affiliates of John Hancock Life Insurance Company ("Hancock") for approximately $82 million, which is net of non-recourse project debt. The non-controlling interest purchased by Hancock represents approximately 125 MW of generating capacity in the Plum Point power generation facility. Following the transaction, our ownership was reduced to 37 percent interest in PPEA, representing an equivalent of approximately 140 MW. The sale met the requirements set forth in SFAS No. 66, "Accounting for Sales of Real Estate". As a result, we recognized a pre-tax gain totaling approximately $39 million ($24 million after-tax) in the fourth quarter 2007. The gain is included in Gain on sale of assets in our consolidated statements of operations.

Rockingham. On November 9, 2006, we completed the sale of the Rockingham facility to Duke Energy Carolinas, LLC (a subsidiary of Duke Energy), which was included in our GEN-WE reportable segment, for $194 million in cash. A portion of the proceeds from the sale were used to repay our borrowings under a $150 million Term Loan, with the remaining proceeds used as an additional source of liquidity. Please read Note 15—Debt—Fifth Amended and Restated Credit Facility for further discussion of the Term Loan.

In accordance with SFAS No. 144, we discontinued depreciation and amortization of the Rockingham power generation facility's property, plant and equipment during the second quarter 2006. Depreciation and amortization expense related to the Rockingham power generation facility totaled $2 million and $6 million in the years ended December 31, 2006 and 2005, respectively. In addition, SFAS No. 144 requires a loss to be recognized if assets held for sale less liabilities held for sale are in excess of fair value less costs to sell. Accordingly, we recorded a pre-tax impairment of $9 million in the year ended December 31, 2006, which is included in Impairment and other charges in our consolidated statements of operations.

West Coast Power. On March 31, 2006, contemporaneous with our purchase of Rocky Road, we completed the sale to NRG of our 50 percent ownership interest in West Coast Power, a joint venture between us and NRG which has ownership interests in the West Coast Power power plants in southern California totaling approximately 1,800 MW. As a result of the two transactions, we received net proceeds of $165 million, net of cash acquired. We did not recognize a material gain or loss on the sale. Pursuant to our divestiture of West Coast Power, we no longer maintain a significant variable interest in the entity as provided by the guidance in FIN No. 46(R). Please read Note 3—Business Combinations and Acquisitions—Rocky Road and Note 12—Variable Interest Entities for further discussion.

GEN-WE Discontinued Operations

Calcasieu. On March 31, 2008, we completed the sale of the Calcasieu power generation facility to Entergy Gulf States, Inc. ("Entergy") for approximately $56 million, net of transaction costs. We recorded a pre-tax impairment of approximately $36 million in the year ended December 31, 2006, which was included in Income (loss) from discontinued operations on our consolidated statements of operations. Please read Note 5—Impairment Charges—Asset Impairments for further discussion.

In accordance with SFAS No. 144, we discontinued depreciation and amortization of the Calcasieu power generation facility's property, plant and equipment during the first quarter 2007. Depreciation and amortization expense related to the Calcasieu power generation facility totaled approximately zero, zero and $2 million in the years ended December 31, 2008, 2007 and 2006, respectively. Also pursuant to SFAS No. 144, we are reporting the results of Calcasieu's operations in discontinued operations for all periods presented.

CoGen Lyondell. On August 1, 2007, we completed the sale of the CoGen Lyondell power generation facility for approximately $470 million to EnergyCo, LLC ("EnergyCo"), a joint venture between PNM Resources and a subsidiary of Cascade Investment, LLC. We recorded a $224 million gain related to the sale of the asset in 2007. The gain includes the impact of allocating approximately $34 million of goodwill associated with the GEN-WE reporting unit to the CoGen Lyondell power generation facility. The amount of goodwill allocated to the CoGen Lyondell power generation facility was based on relative fair values of the CoGen Lyondell power generation facility and the portion of the GEN-WE reporting unit being retained.

In accordance with SFAS No. 144, we discontinued depreciation and amortization of the CoGen Lyondell power generation facility's property, plant and equipment during the second quarter 2007. Depreciation and amortization expense related to the CoGen Lyondell power generation facility totaled approximately $5 million and $11 million in the years ended December 31, 2007 and 2006, respectively. Also pursuant to SFAS No. 144, we are reporting the results of CoGen Lyondell's operations in discontinued operations for all periods presented.

The sale of the CoGen Lyondell power generation facility represented the sale of a significant portion of a reporting unit. As such, in accordance with SFAS No. 142, during the third quarter 2007, we tested the goodwill of the GEN-WE reporting unit for impairment. No impairment was indicated as a result of this test.

Other Discontinued Operations

In 2007 and 2006, we recognized approximately $11 million and $21 million of pre-tax income related to favorable settlements of legacy receivables.

The following table summarizes information related to Dynegy's discontinued operations:

	GEN-WE	CRM	DGC	NGL	Total
		(in millions)			
2008					
Income from operations before taxes	$—	$—	$—	$ 4	$ 4
Income from operations after taxes	—	—	—	3	3
2007					
Revenues	$307	$—	$—	$—	$307
Income from operations before taxes	1	15	(1)	—	15
Income (loss) from operations after taxes	1	15	—	11	27
Gain on sale before taxes	224	—	—	—	224
Gain on sale after taxes	121	—	—	—	121
2006					
Revenues	$247	$—	$—	$—	$247
Income (loss) from operations before taxes	(53)	23	1	6	(23)
Income (loss) from operations after taxes	(37)	19	1	4	(13)

The following table summarizes information related to DHI's discontinued operations:

	GEN-WE	CRM	NGL	Total
		(in millions)		
2008				
Income from operations before taxes	$—	$—	$ 4	$ 4
Income from operations after taxes	—	—	3	3
2007				
Revenues	$307	$—	$—	$307
Income from operations before taxes	1	15	—	16
Income (loss) from operations after taxes	1	15	11	27
Gain on sale before taxes	224	—	—	224
Gain on sale after taxes	121	—	—	121
2006				
Revenues	$247	$—	$—	$247
Income (loss) from operations before taxes	(53)	23	6	(24)
Income (loss) from operations after taxes	(37)	21	4	(12)

Note 5—Impairment Charges

Asset Impairments. At December 31, 2008, we determined that it was more likely than not that the Heard County power generation facility would be sold prior to the end of its previously estimated useful life. In accordance with SFAS No. 144, we performed an impairment analysis and recorded a pre-tax impairment charge of $47 million ($27 million after tax). This charge is recorded in the GEN-WE segment and is included in Impairment and other charges in our consolidated statements of operations. We determined the fair value of the Heard County facility using the expected present value technique and probability-weighted cash flows incorporating potential sales prices due to recent negotiations.

In 2008, we recorded a $71 million pre-tax loss related to our investment in DLS Power Holdings, which consisted of an impairment of $24 million and a $47 million loss on dissolution. Please read Note 11—Unconsolidated Investments for further discussion.

At December 31, 2006, we determined that it was more likely than not certain assets would be sold prior to the end of their previously estimated useful lives. Therefore, impairment analyses were performed and we recorded a total pre-tax impairment charge of $50 million ($32 million after tax). Of this charge, $36 million related to the Calcasieu facility and is recorded in the GEN-WE segment and is included in Income (loss) from discontinued operations on our consolidated statements of operations. The remaining $14 million relates to the Bluegrass facility and is recorded in the GEN-MW segment. This charge is included in Impairment and other charges in our consolidated statements of operations. We determined the fair value of the Bluegrass facility using the expected present value technique. We determined the fair value of the Calcasieu facility based on the purchase price in the sales agreement.

At September 30, 2006, we tested the Bluegrass generation facility for impairment based on FERC's approval and Louisville Gas and Electric's ("LG&E") completion of various compliance steps to allow it to withdraw its transmission facilities from the MISO as of September 1, 2006. The Bluegrass facility has historically sold power into the MISO market through transmission provided by LG&E. This change limits our ability or increases the cost to deliver power to the MISO market. After testing, we recorded a pre-tax impairment charge of $96 million ($61 million after-tax) in the GEN-MW segment. This charge is included in Impairment and other charges in our consolidated statements of operations. We determined the fair value of the facility using the expected present value technique.

In 2006, we recorded a $9 million pre-tax impairment of our investment in Nevada Cogeneration Associates #2 ("Black Mountain"). Please read Note 11—Unconsolidated Investments for further discussion.

Note 6—Risk Management Activities, Derivatives and Financial Instruments

The nature of our business necessarily involves market and financial risks. Specifically, we are exposed to commodity price variability related to our power generation business. Our commercial team manages these commodity price risks with financially settled and other types of contracts consistent with our commodity risk management policy. Our commercial team also uses financial instruments in an attempt to capture the benefit of fluctuations in market prices in the geographic regions where our assets operate. Our treasury team manages our financial risks and exposures associated with interest expense variability.

Our commodity risk management strategy gives us the flexibility to sell energy and capacity through a combination of spot market sales and near-term contractual arrangements (generally over a rolling 12 to 36 month time frame). Our commodity risk management goal is to protect cash flow in the near-term while keeping the ability to capture value longer-term. Many of our contractual arrangements are derivative instruments and must be accounted for at fair value pursuant to the guidance in SFAS No. 133. We also manage commodity price risk by entering into capacity forward sales arrangements, tolling arrangements, RMR contracts, fixed price coal purchases and other arrangements that do not receive fair value accounting treatment because these arrangements do not meet the definition of a derivative or are designated as "normal purchase normal sales". As a result, the gains and losses with respect to these arrangements are not reflected in the consolidated statements of operations until the settlement dates.

The following table summarizes the carrying value and fair value of the derivatives used in our risk management activities. In the table below, commodity-based derivative contracts primarily represent derivative contracts related to our power generation business that we have not designated as accounting hedges, that are entered into for purposes of hedging future fuel requirements and sales commitments and securing commodity prices we consider favorable under the circumstances.

	December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Interest rate derivatives designated as cash flow accounting hedges	$(238)	$(238)	$ (34)	$ (34)
Interest rate derivatives designated as fair value accounting hedges	3	3	2	2
Interest rate derivatives not designated as accounting hedges	(2)	(2)	(2)	(2)
Commodity-based derivative contracts not designated as accounting hedges	207	207	(66)	(66)
Net liabilities from risk management activities (1)	$ (30)	$ (30)	$(100)	$(100)

(1) Included in both current and non-current assets and liabilities on the consolidated balance sheets.

Beginning April 2, 2007, we chose to cease designating derivatives related to our power generation business as cash flow hedges, and thus apply mark-to-market accounting treatment thereafter. Accordingly, as fair values fluctuate from period to period due to market price volatility, fair value changes and unrealized and realized gains and losses are reflected in the consolidated statements of operations within Revenues pursuant to EITF Issue 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" ("EITF Issue No. 02-3"). As such, 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.

For the twelve months ended December 31, 2008, our revenues included approximately $253 million of mark-to-market gains related to this activity compared to $32 million and $13 million of mark-to-market losses in the periods ended December 31, 2007 and 2006, respectively.

Cash Flow Hedges. We enter into financial derivative instruments that qualify, and that we may elect to designate, as cash flow hedges. Interest rate swaps have been used to convert floating interest rate obligations to fixed interest rate obligations. Additionally, prior to April 2, 2007, we applied the cash flow hedge accounting model to certain GEN derivatives as discussed above. The balance in Accumulated other comprehensive loss at April 2, 2007 related to these instruments has been reclassified contemporaneously with the related purchases of fuel and sales of electricity. As of December 31, 2008, there was no pre-tax income remaining in Accumulated other comprehensive loss on the consolidated balance sheets.

During the twelve month periods ended December 31, 2008, 2007 and 2006 we recorded $2 million, $9 million and $7 million, respectively, of income related to ineffectiveness from changes in the fair value of cash flow hedge positions. No amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows in any of the periods. During the twelve month periods ended December 31, 2008, 2007 and 2006, no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable of occurring.

The balance in cash flow hedging activities, net at December 31, 2008, is expected to be reclassified to future earnings when the hedged transaction impacts earnings. Of this amount, after-tax losses of approximately

$1 million are currently estimated to be reclassified into earnings over the 12 month period ending December 31, 2009. The actual amounts that will be reclassified into earnings over this period and beyond could vary materially from this estimated amount as a result of changes in market conditions and other factors.

Fair Value Hedges. We also enter into derivative instruments that qualify, and that we designate, as fair value hedges. We use interest rate swaps to convert a portion of our non-prepayable fixed-rate debt into floating-rate debt. During the twelve month periods ended December 31, 2008, 2007 and 2006, there was no ineffectiveness from changes in the fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. During the twelve month periods ended December 31, 2008, 2007 and 2006, no amounts were recognized in relation to firm commitments that no longer qualified as fair value hedges.

Fair Value Measurements. The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value as of December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Assets from commodity risk management activities	$—	$1,282	$ 73	$1,355
Assets from interest rate swaps	—	22	—	22
Other—DHI (1)	—	24	—	24
Total—DHI	—	1,328	73	1,401
Other—Dynegy (1)	—	1	—	1
Total—Dynegy	$—	$1,329	$ 73	$1,402
Liabilities:				
Liabilities from commodity risk management activities	$—	$1,134	$ 13	$1,147
Liabilities from interest rate swaps	—	260	—	260
Total—Dynegy and DHI	$—	$1,394	$ 13	$1,407

(1) Other represents available for sale securities.

The following table sets forth a reconciliation of changes in the fair value of financial instruments classified as Level 3 in the fair value hierarchy:

	Twelve Months Ended December 31, 2008
	(in millions)
Balance at December 31, 2007	$(16)
Realized and unrealized gains, net	105
Purchases, issuances and settlements	(28)
Transfers out of Level 3	(1)
Balance at December 31, 2008	$ 60
Change in unrealized gains, net, relating to instruments still held as of December 31, 2008	$ 85

Gains and losses (realized and unrealized) for Level 3 recurring items are included in Revenues on the consolidated statements of operations. We believe an analysis of instruments classified as Level 3 should be undertaken with the understanding that these items generally serve as economic hedges of our power generation portfolio.

Transfers in and/or out of Level 3 represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

Fair Value of Financial Instruments. The disclosure above related to the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, "Disclosures About Fair Value of Financial Instruments". We have determined the estimated fair-value amounts using available market information and selected valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies could have a material effect on the estimated fair-value amounts.

The carrying values of current financial assets and liabilities approximate fair values due to the short-term maturities of these instruments. The carrying amounts and fair values of debt are included in Note 15—Debt and the carrying amounts.

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

At December 31, 2008, our credit exposure as it relates to the mark-to-market portion of our risk management portfolio totaled $204 million. We seek to reduce our credit exposure by executing agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to further reduce credit risk with certain counterparties by obtaining third party guarantees or collateral as well as the right of termination in the event of default.

Our Credit Department establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical delivery and financial contracts. Our credit risk system provides current credit exposure to counterparties on a daily basis.

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

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

Note 7—Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax (except foreign currency translation adjustment), is included in Dynegy's stockholders' equity and DHI's stockholder's equity on the consolidated balance sheets, respectively, as follows:

	Year Ended December 31,	
	2008	2007
	(in millions)	
Cash flow hedging activities, net	$(125)	$ (39)
Foreign currency translation adjustment (1)	—	27
Unrecognized prior service cost and actuarial loss	(66)	(25)
Available for sale securities	—	12
Accumulated other comprehensive loss—unconsolidated investments	(24)	—
Accumulated other comprehensive loss, net of tax	$(215)	$ (25)

(1) In 2008, upon substantial liquidation of a foreign entity, we recognized $24 million of pre-tax income related to translation gains that had accumulated in stockholder's equity. This income is included in Other income (expense), net in our consolidated statements of operations.

Note 8—Cash Flow Information

Following are Dynegy's supplemental disclosures of cash flow and non-cash investing and financing information:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Interest paid (net of amount capitalized)	$413	$ 393	$405
Taxes paid, net	$ 23	$ 48	$ 9
Detail of businesses acquired:			
Current assets and other	$—	$ 174	$ 14
Fair value of non-current assets	—	5,122	13
Liabilities assumed, including deferred taxes	—	(2,766)	18
Non-cash consideration (1)	—	(2,378)	—
Cash balance acquired	—	(16)	(5)
Cash paid, net of cash acquired (2)	$—	$ 136	$ 40
Other non-cash investing and financing activity:			
Non-cash capital expenditures (3)	$ 57	$ 13	$—
Conversion of Convertible Subordinated Debentures due 2023 (Note 15) (4)	—	—	225
Sithe Subordinated Debt exchange, net (Note 15) (5)	—	—	122
Addition of a capital lease (6)	—	—	6
Marketable securities (7)	—	—	18

(1) Includes (i) 340 million shares of the Class B common stock of Dynegy valued at $5.98 per share; (ii) a promissory note in the aggregate principal amount of $275 million, and (iii) an additional $70 million of the Griffith Debt. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for further information.

(2) Includes transaction costs associated with the Merger of approximately $44 million and $8 million for the years ended December 31, 2007 and 2006, respectively.

(3) For the years ended December 31, 2008 and 2007, we had non-cash capital expenditures of approximately $57 million and $13 million, respectively. These expenditures related primarily to our interest in the Plum Point power generation facility and capital expenditures related to the Consent Decree. Please read Note 12—Variable Interest Entities—PPEA Holding Company LLC for further discussion of Plum Point and Note 19—Commitment and Contingencies for further discussion of the Consent Decree.

(4) In May 2006, Dynegy converted all $225 million of its outstanding 4.75 percent Convertible Subordinated Debentures due 2023 into shares of its Class A common stock (the "Convertible Debenture Exchange"). In this transaction, Dynegy issued an aggregate of 54,598,369 shares of our Class A common stock and paid the debenture holders an aggregate of approximately $47 million in premiums and accrued and unpaid interest using cash on hand. Please read Note 15—Debt— Convertible Subordinated Debentures due 2023 for further information.

(5) In July 2006, we executed an exchange of approximately $419 million principal amount of the subordinated debt of Independence, together with all claims for accrued and unpaid interest thereon, for approximately $297 million principal amount of our 8.375 percent Senior Unsecured Notes due 2016. Please read Note 15—Debt—Sithe Senior Notes for further information.

(6) 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 generating facility. Pursuant to our agreement with the lessor, we are obligated for minimum payments in the aggregate amount of $14 million over the ten-year term of the lease.

(7) In November 2006, the New York Mercantile Exchange completed its initial public offering. We had two membership seats on the NYMEX, and therefore, we received 90,000 NYMEX shares for each membership seat.

Following are DHI's supplemental disclosures of cash flow and non-cash investing and financing information:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Interest paid (net of amount capitalized)	$413	$ 393	$402
Taxes paid, net	$ 18	$ 35	$—
Detail of businesses acquired:			
Current assets and other	$—	$ —	$ 14
Fair value of non-current assets	—	—	13
Liabilities assumed, including deferred taxes	—	—	18
Cash balance acquired	—	—	(5)
Cash paid, net of cash acquired	$—	$ —	$ 40
Other non-cash investing and financing activity:			
Non-cash capital expenditures (1)	$ 57	$ 13	$—
Contribution of the Contributed Entities from Dynegy to DHI (2)	—	2,467	—
Contribution of Sithe from Dynegy to DHI (3)	—	—	—
Contribution of Sandy Creek from Dynegy to DHI (4)	—	16	—
Sithe Subordinated Debt exchange, net (Note 15) (5)	—	—	122
Addition of a capital lease (6)	—	—	6
Marketable securities (7)	—	—	18

(1) For the years ended December 31, 2008 and 2007, we had non-cash capital expenditures of approximately $57 million and $13 million, respectively. These expenditures related primarily to our interest in the Plum Point power generation facility and capital expenditures related to the Consent Decree. Please read Note 12—Variable Interest Entities—PPEA Holding Company LLC for further discussion of Plum Point and Note 19—Commitment and Contingencies for further discussion of the Consent Decree.
(2) In April 2007, Dynegy contributed to DHI its interest in the Contributed Entities. The contribution was accounted for as a transaction between entities under common control in a manner similar to a pooling of interests whereby the assets and liabilities were transferred at historical cost. Please read Note 3—Business Combinations and Acquisitions—LS Assets Contribution for further information.
(3) In April 2007, Dynegy contributed to DHI its interest in New York Holdings. This contribution was accounted for as a transaction between entities under common control in a manner similar to a pooling of interests whereby the assets and liabilities were transferred at historical cost. Please read Note 3—Business Combinations and Acquisitions—Sithe Assets Contribution for further information.
(4) In August 2007, Dynegy contributed to DHI its interest in SCH. This contribution was accounted for as a transaction between entities under common control in a manner similar to a pooling of interests whereby the assets and liabilities were transferred at historical cost. Please read Note 12—Variable Interest Entities—Sandy Creek for further information.
(5) In July 2006, DHI executed an exchange of approximately $419 million principal amount of the subordinated debt of Independence, together with all claims for accrued and unpaid interest thereon, for approximately $297 million principal amount of DHI's 8.375 percent Senior Unsecured Notes due 2016. Please read Note 15—Debt—Sithe Senior Notes for further information.
(6) 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 generating facility. Pursuant to our agreement with the lessor, we are obligated for minimum payments in the aggregate amount of $14 million over the ten-year term of the lease.
(7) In November 2006, the New York Mercantile Exchange completed its initial public offering. We had two membership seats on the NYMEX, and therefore, we received 90,000 NYMEX shares for each membership seat.

Note 9—Inventory

A summary of our inventories is as follows:

	December 31, 2008	December 31, 2007
	(in millions)	
Materials and supplies	$ 76	$ 72
Coal	57	70
Fuel oil	29	40
Emissions allowances	18	11
Natural gas storage	4	6
	$184	$199

Note 10—Property, Plant and Equipment

A summary of our property, plant and equipment is as follows:

	December 31, 2008	December 31, 2007
	(in millions)	
Generation assets:		
GEN-MW	$ 6,825	$ 6,642
GEN-WE	2,390	2,393
GEN-NE	1,501	1,464
IT systems and other	153	190
	10,869	10,689
Accumulated depreciation	(1,935)	(1,672)
	$ 8,934	$ 9,017

Interest capitalized related to costs of construction projects in process totaled $23 million, $15 million and $3 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Note 11—Unconsolidated Investments

Equity Method Investments. Our equity method investments consist of investments in affiliates that we do not control, but where we have significant influence over operations. Our principal equity method investments consist of entities that develop and construct generation assets. We entered into these ventures principally to share risk and leverage existing commercial relationships.

A summary of our unconsolidated investments in equity method investees is as follows:

	December 31, 2008	December 31, 2007
	(in millions)	
Equity affiliates:		
Sandy Creek Services	$—	$—
Sandy Creek Holdings LLC	(75)(1)	18
Black Mountain	—	—
Total unconsolidated investments—DHI	(75)	18
DLS Power Holdings and DLS Power Development	15	61
Total unconsolidated investments—Dynegy	$ (60)	$ 79

(1) Included in Other long-term liabilities on the consolidated balance sheets.

Cash distributions received from our equity investments during 2008, 2007 and 2006 were $16 million, $10 million and zero, respectively. Undistributed earnings from our equity investments included in accumulated deficit at December 31, 2008 and 2007 totaled $101 million and $16 million, respectively.

Our equity investments at December 31, 2008 include a 50 percent ownership interest in SCH, which owns all of Sandy Creek Energy Associates LP ("SCEA"). SCEA owns a 64 percent interest in the Sandy Creek Project, an 898 MW coal-fired power generation facility under construction in McLennan County, Texas. Please read Note 12—Variable Interest Entities—Sandy Creek for further information.

In addition, our equity investments include a 50 percent ownership interest in Black Mountain, an 85 MW power generation facility in Las Vegas, Nevada. During the twelve months ended December 31, 2008, 2007 and 2006, we recorded impairment charges of $1 million, $7 million and $9 million, respectively, related to our 50 percent interest in Black Mountain. These charges are the result of declines in value of the investment caused by an increase in the cost of fuel in relation to a third party power purchase agreement through 2023 for 100 percent of the output of the facility. This agreement provides that Black Mountain will receive payments that decrease over time. Please read Note 19—Commitments and Contingencies—Legal Proceedings—Nevada Power Arbitration for further information.

Dynegy's equity investments also include a 50 percent ownership interest in DLS Power Holdings and DLS Power Development LLC. The purpose of DLS Power Development was to provide services to DLS Power Holdings and the project subsidiaries related to power project development and to evaluate and pursue potential new development projects. Effective January 1, 2009, Dynegy entered into an agreement with LS Power Associates, L.P. to dissolve DLS Power Holdings and DLS Power Development LLC. Please read Note 12—Variable Interest Entities—DLS Power Holdings and DLS Power Development for further information.

Summarized Information. Summarized aggregate financial information for our unconsolidated equity investment in SCH and its equity share thereof was:

	December 31,			
	2008		2007	
	Total	Equity Share	Total	Equity Share
	(in millions)			
Current assets	$ 6	$ 3	$ 6	$ 3
Non-current assets	384	192	262	131
Current liabilities	32	16	14	7
Non-current liabilities	536	268	280	140
Revenues	—	—	—	—
Operating income	36	18	26	13
Net income (loss)	(80)	(40)	16	8

Summarized aggregate financial information for Dynegy's unconsolidated equity investment in DLS Power Holdings and Dynegy's equity share thereof was:

	December 31,			
	2008		2007	
	Total	Equity Share	Total	Equity Share
	(in millions)			
Current assets	$ 4	$ 2	$ 2	$ 1
Non-current assets	10	5	4	2
Current liabilities	4	2	4	2
Non-current liabilities	2	1	2	1
Revenues	—	—	—	—
Operating loss	(23)	(12)	(19)	(9)
Net loss	(23)	(12)	(19)	(9)

Dynegy's Losses from unconsolidated investments of $123 million for the year ended December 31, 2008, include $40 million from SCH and $83 million from DLS Power Holdings. In addition to the $12 million noted above, Dynegy's losses of $83 million from its investment in DLS Power Holdings include a $24 million impairment and a $47 million loss on dissolution. Please read Note 12—Variable Interest Entities for further discussion. Dynegy's Losses from unconsolidated investments of $3 million for the year ended December 31, 2007 include losses of $9 million from DLS Power Holdings offset by income of $6 million from SCH and income of less than $1 million from Sandy Creek Services. The $6 million from SCH includes the $8 million above, the elimination of $2 million in commitment fees payable to Dynegy that was expensed by SCH, offset by a reduction in our investment of $5 million due to the sale of an interest in the Sandy Creek Project to Brazos. Please read Note 12—Variable Interest Entities for further discussion.

DHI's Losses from unconsolidated investments of $40 million for the year ended December 31, 2008, include $40 million from SCH. DHI's Earnings from unconsolidated investments of $6 million for the year ended December 31, 2007 include $6 million from SCH and income of less than $1 million from Sandy Creek Services. The $6 million from SCH includes the $8 million above, the elimination of $2 million in commitment fees payable to Dynegy that was expensed by SCH, offset by a reduction in our investment of $5 million due to the sale of an interest in the Sandy Creek Project to Brazos. Please read Note 12—Variable Interest Entities for further discussion.

Available-for-Sale Securities. As of December 31, 2008, Dynegy and DHI had approximately $25 million and $24 million, respectively, invested in the Reserve Primary Fund (the "Fund"), which "broke the buck" on September 16, 2008, when the value of its shares fell below $1.00. On September 22, 2008, the SEC granted the Fund's request to suspend all rights of redemption from the Fund, in order to ensure an orderly disposition of the securities. Since distributions from the Fund were suspended on September 30, 2008, investments in the Fund are no longer readily convertible to cash, and therefore do not meet the definition of "cash and cash equivalents" as set forth in SFAS No. 95, "Statement of Cash Flows". As a result, we have reclassified our investment in the Fund from cash and cash equivalents to short-term investments as of December 31, 2008 and recorded a $2 million impairment, based on management's estimate of the fair value of our proportionate share of the Fund's holdings, which is included in Other income and expense, net, in our consolidated statements of operations. This investment is classified as a current asset, as all of the assets held by the Fund will mature by September 30, 2009, and distributions from the Fund will be made as assets reach maturity or are sold.

In November 2006, the New York Mercantile Exchange ("NYMEX") completed its initial public offering. We had two membership seats on the NYMEX, and therefore, we received 90,000 NYMEX shares for each membership seat. During August 2007, we sold approximately 30,000 shares for approximately $4 million, and we recognized a gain of $4 million. During the second quarter 2008, we sold our remaining 150,000 shares and both of our membership seats for approximately $16 million, and we recognized a gain of $15 million, which is included in Gain on sale of assets in our consolidated statements of operations; partially offset by a reduction of $8 million, net of tax of $5 million, in our condensed consolidated statements of other comprehensive income. Our investment in the NYMEX shares was valued at approximately $21 million at December 31, 2007.

Note 12—Variable Interest Entities

Hydroelectric Generation Facilities. On January 31, 2005, Dynegy completed the acquisition of ExRes. As further discussed in Note 3—Business Combinations and Acquisitions—Sithe Assets Contribution, on April 2, 2007, Dynegy contributed its interest in the Sithe Assets to DHI. ExRes also owns through its subsidiaries four hydroelectric generation facilities, with total capacity of 51 MW, in Pennsylvania. The entities owning these facilities meet the definition of VIEs. In accordance with the purchase agreement, Exelon Corporation ("Exelon") has the sole and exclusive right to direct our efforts to decommission, sell, bankrupt, or otherwise dispose of the hydroelectric facilities owned through the VIE entities. Exelon is obligated to reimburse ExRes for all costs, liabilities, and obligations of the entities owning these hydroelectric generation facilities, and to indemnify ExRes with respect to the past and present assets and operations of the entities. As a result, we are not the primary beneficiary of the entities and have not consolidated them in accordance with the provisions of FIN No. 46(R).

These hydroelectric generation facilities have commitments and obligations that are off-balance sheet with respect to Dynegy arising under operating leases for equipment and long-term power purchase agreements with local utilities. At December 31, 2008, the equipment leases have remaining terms from eleven months to twenty-two years, including options to extend two of the leases and involve future lease payments of $140 million over the terms of the leases, including lease payments for the optional extended terms. Additionally, each of these facilities is party to a long-term power purchase agreement with a local utility. Under the terms of each of these agreements, a project tracking account (the "Tracking Account") was established to quantify the difference between (i) the facility's fixed price revenues under the power purchase agreement and (ii) the respective utility's Public Utility Commission approved avoided costs associated with those power purchases plus accumulated interest on the balance. Each power purchase agreement calls for the hydroelectric facility to return to the utility the balance in the Tracking Account before the end of the facility's life through decreased pricing under the respective power purchase agreement. All four of the hydroelectric facilities are currently in the Tracking Account repayment period of the contract, whereby balances are repaid through decreased pricing. This pricing cannot be decreased below a level sufficient to allow the facilities to recover their operating costs, exclusive of lease or interest costs. The aggregate balance of the Tracking Accounts as December 31, 2008 was approximately $373 million, and the obligations with respect to each Tracking Account are secured by the assets of the respective facility. The decreased pricing necessary to reduce the Tracking Accounts may cause the facilities to operate at a net cash deficit. As discussed above, the obligations of the four hydroelectric facilities are non-recourse to us. Under the terms of the stock purchase agreement with Exelon, we are indemnified for any net cash outflow arising from ownership of these facilities.

PPEA Holding Company LLC. On April 2, 2007, in connection with the completion of the Merger, we acquired 600 of the 900 outstanding Class A Units and all 100 Class B Units in PPEA, which represented an ownership interest of approximately 70 percent. PPEA owns Plum Point. Plum Point is constructing a 665 MW coal-fired power generation facility, located in Mississippi County, Arkansas, in which it owns an approximate 57 percent undivided interest. Also on April 2, 2007, Dynegy became the Project Manager of the Plum Point Project. Under the terms of the Project Management Agreement, we receive $2 million annually, plus out of pocket costs, during the construction period and approximately $2 million annually, plus out of pocket costs, once commercial operations commence. The Project Management Agreement expires 15 years after the commercial operations date, which is expected in August 2010.

On December 13, 2007, we sold 300 of our Class A Units and 30 of our Class B Units in PPEA for approximately $82 million, reducing our ownership interest to 37 percent. On February 28, 2008, we entered into an Operations and Maintenance Agreement with Plum Point and the other owners of the Plum Point Project to be the operator of the facility for $1 million annually, plus out-of-pocket costs. On December 31, 2008, we gave notice of our intention to terminate this agreement effective April 30, 2009.

At the acquisition date and continuing after the sale, we have determined that we are the primary beneficiary of PPEA because we will continue to absorb a majority of the expected losses primarily as a result of the Class B Units absorbing a disproportionate share of income and losses over the expected life of the project. The expected loss calculation includes assumptions about forecasted cash flows, construction costs and plant performance. As such, PPEA is included in our consolidated financial statements in accordance with the provisions of FIN No. 46(R).

Plum Point is the Borrower under a $700 million term loan facility (the "Term Loan Facility"), a $17 million revolving credit facility (the "Revolving Credit Facility"), and a $102 million letter of credit facility securing $100 million of Tax Exempt Bonds (the "LC Facility"). The payment obligations of Plum Point in respect of the Term Loan Facility, the Revolving Credit Facility, and the LC Facility are unconditionally and irrevocably guaranteed by Ambac Assurance Corporation, an independent third party insurance company. The credit facilities and insurance policy are secured by a security interest in all of Plum Point's assets, contract rights and Plum Point's undivided tenancy in common interest in the Plum Point Project and PPEA's interest in Plum Point. There are no guarantees of the indebtedness by any parties, and Plum Point's creditors have no recourse against our general credit. Please read Note 15—Debt—Plum Point Credit Agreement Facility and Note 15—Debt—Plum Point Tax Exempt Bonds for discussion of Plum Point's borrowings.

As of December 31, 2008, we have posted $15 million in letters of credit to support our contingent equity contribution to Plum Point. Hancock and EIF have also posted $15 million and $16 million letters of credit, respectively, to support their contingent equity contributions to Plum Point. Other than providing services under the Project Management Agreement and the Operations and Maintenance Agreements discussed above, we have not provided any other financial or other support to PPEA.

Summarized aggregate financial information for PPEA Holding Company, included in our consolidated financial statements, is included below:

	As of and For the Year Ended	
	2008	2007
	(in millions)	
Current assets	$ 1	$ 16
Property, plant and equipment, net	507	308
Intangible asset	193	193
Other non-current asset	29	40
Total assets	730	557
Current liabilities	19	20
Long-term debt	615	418
Non-current liabilities	244	42
Minority interest	(30)	23
Operating loss	(1)	(1)
Net loss	(3)	(1)

DLS Power Holdings and DLS Power Development. As discussed in Note 3—Business Combinations and Acquisitions—LS Power Business Combination, on April 2, 2007, in connection with Merger, Dynegy acquired a 50 percent interest in DLS Power Holdings and DLS Power Development. The purpose of DLS Power Development is to provide services to DLS Power Holdings and the project subsidiaries related to power project development and to evaluate and pursue potential new development projects. DLS Power Holdings and DLS Power Development meet the definition of VIEs, as they will require additional subordinated financial support from their owners to conduct normal on-going operations. Dynegy determined that it is not the primary beneficiary of the entities because LS Power, a related party, is more closely associated with the entities as they are the managing partner of the entities, own approximately 40 percent of Dynegy's outstanding common stock and have three seats on Dynegy's Board of Directors. Therefore, in accordance with the provisions of FIN No. 46(R), Dynegy has not consolidated the entities.

Dynegy accounts for its investments in DLS Power Holdings and DLS Power Development as equity method investments pursuant to APB 18, "The Equity Method of Accounting for Investments in Common Stock". Dynegy made contributions to the joint ventures of approximately $16 million and $10 million, respectively, during the years ended December 31, 2008 and 2007, respectively, to fund its share of the entities' development efforts.

In December 2008, Dynegy executed an agreement with LS Associates to dissolve DLS Power Holdings and DLS Power Development effective January 1, 2009. Under the terms of the dissolution, Dynegy acquired exclusive rights, ownership and developmental control of all repowering or expansion opportunities related to its existing portfolio of operating assets. LS Associates received approximately $19 million in cash from Dynegy on January 2, 2009, and acquired full ownership and developmental rights associated with various "greenfield" projects under consideration in Arkansas, Georgia, Iowa, Michigan and Nevada, as well as other power generation and transmission development projects not related to Dynegy's existing operating portfolio of assets.

For the year ended December 31, 2008, Dynegy recorded losses related to its equity investment of approximately $83 million. These losses consisted of a $24 million impairment charge, a $47 million loss on the dissolution and $12 million of equity losses. The impairment charge is the result of a decline in the fair value of the development projects during the fourth quarter 2008 as a result of increasing barriers to the development and construction of new generation facilities, including credit and regulatory factors. The loss on the dissolution primarily relates to consideration paid related to the following items which have value to Dynegy, but which do not qualify as assets for accounting purposes: (i) exclusive rights to the potential expansion of its existing facilities; (ii) redirection of management time and resources to other projects; (iii) the allocation to Dynegy of full access and control over current and future expansion opportunities; and (iv) enhancement of Dynegy's strategic flexibility. These losses are included in Losses from unconsolidated investments in Dynegy's consolidated statements of operations.

On December 31, 2008, Dynegy had approximately $15 million included in Unconsolidated investments and $19 million in Accounts payable in its consolidated balance sheet, which related to Dynegy's obligation to pay LS Power Associates approximately $19 million in cash in consideration for the dissolution. Dynegy's maximum exposure to economic loss from these VIEs is limited to $34 million.

Sandy Creek. In connection with its acquisition of a 50 percent interest in DLS Power Holdings, as further discussed above, Dynegy acquired a 50 percent interest in SCH, which owns all of SCEA. SCEA owns an undivided interest in the Sandy Creek Project. In August 2007, SCH became a stand-alone entity separate from DLS Power Holdings, and its wholly owned subsidiaries, including SCEA, entered into various financing agreements to construct its portion of the Sandy Creek Project.

Dynegy Sandy Creek Holdings, LLC (the "Dynegy Member"), an indirectly wholly owned subsidiary of Dynegy, and LSP Sandy Creek Member, LLC (the "LSP Member") each own a 50 percent interest in SCH. In addition, Sandy Creek Services, LLC ("SC Services") was formed to provide services to SCH. Dynegy Power Services and LSP Sandy Creek Services LLC each own a 50 percent interest in SC Services.

Dynegy's 50 percent interest in SCH, as well as a related intangible asset of approximately $23 million, were subsequently contributed to a wholly owned subsidiary of DHI. This contribution was accounted for as a transaction between entities under common control. As such, DHI's investment in SCH, as well as the related intangible asset, were recorded by DHI at Dynegy's historical cost on the acquisition date. DHI's investment in SCH is included in GEN-WE.

The original financing agreements consisted of a $200 million term loan and $800 million in construction commitments with SCEA as borrower. The SCEA debt is secured by a pledge of SCEA's assets and contract rights and SCEA's undivided tenancy in common interest in the Sandy Creek Project as well as a pledge of the equity of SCEA by its direct parents.

In connection with the SCEA term and construction financing described above, SCH entered into arrangements to make capital contributions to SCEA of up to $200 million to fund its equity commitments after the loans under the SCEA financing have been utilized and otherwise upon certain conditions. SCH's obligation to make such contributions is supported by a credit agreement with the Dynegy Member and LSP Member, as lenders, and SCH, as borrower. The lenders provide for commitments of $200 million in loans to SCH. This SCH debt is secured by a pledge of SCH's indirect ownership interests in SCEA.

The Dynegy Member and the LSP Member each also agreed to make equity contributions of $223 million to fund project costs after the SCEA and SCH equity contributions have been utilized and otherwise upon the occurrence of certain events and milestone dates.

In August 2007, upon the close of the financing agreements discussed above, SCEA sold a 25 percent undivided interest in the Sandy Creek Project for approximately $30 million plus reimbursement for a related portion of accumulated construction costs and the obligation to assume a proportionate share of future construction costs. During 2007, we recognized our share of the gain on the sale, which approximated $10 million, in Earnings from unconsolidated investments on our consolidated statements of operations. During 2007, SCEA received $24 million in cash proceeds, consisting of approximately $15 million of the purchase price and $9 million for the purchaser's share of accumulated costs. The remainder of the purchase price, plus accrued interest, is expected to be collected in 2010. SCEA distributed the cash proceeds from the sale to the Dynegy Member and the LSP Member in 2007.

In June 2008, SCEA sold an approximate 11 percent interest in the Sandy Creek Project. As a result, SCEA currently owns an approximate 64 percent interest in the Sandy Creek Project. Losses from unconsolidated investments for the year ended December 31, 2008 includes a 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 to the Senior Secured Lenders and approximately $7 million in affiliate debt to the Dynegy Member and the LSP Member. As a result of the sale, SCEA's availability under the financing agreements was reduced to $155 million for the term loan and $696 million for the construction loans. In addition, both the Dynegy Member and the LSP Member received a cash distribution of approximately $7 million during 2008. As a result of the sale, SCH's equity commitment was reduced from $200 million to $170 million. In addition, the LS Member's and the Dynegy Member's funding commitments to SCEA were each reduced from $223 million to $190 million.

The Dynegy Member's 50 percent share of the SCH credit agreement and its funding commitment to SCEA are supported by letters of credit totaling $275 million issued under a stand-alone letter of credit facility between the Dynegy Member and ABN AMRO Bank, N.V. Such letter of credit may be drawn upon by the SCEA lenders if certain conditions are met.

In 2007 and 2008, we provided credit support as discussed above and also provided construction management services to SC Services. We have been reimbursed for the construction management services at cost. No other support was provided to these entities in 2007 and 2008.

SCH and SC Services both meet the definition of a VIE, as they will require additional subordinated financial support to conduct their normal on-going operations. We determined that we are not considered the primary beneficiary of the entities because LS Power, a related party, is more closely associated with the entities as they are the lead party on negotiating commercial and financing arrangements, significantly influenced the design of the entity and the facility, own approximately 40 percent of Dynegy's outstanding common stock and have three seats on Dynegy's Board of Directors. Therefore, in accordance with FIN No. 46(R), we do not consolidate SCH or SC Services.

We account for our investments in SCH and SC Services as equity method investments pursuant to APB 18. At December 31, 2008, we had $4 million included in non-current Accounts receivable, affiliate and $75 million included in Other long-term liabilities on our consolidated balance sheets. Our maximum exposure to economic loss from these VIEs is limited to $279 million.

Note 13—Goodwill

Assets and liabilities of companies acquired in purchase transactions are recorded at fair value at the date of acquisition. Goodwill represents the excess purchase price over the fair value of net assets acquired, plus any identifiable intangibles. Dynegy acquired the Contributed Entities on April 2, 2007, resulting in goodwill of $486 million. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for further discussion of the acquisition, Note 4—Dispositions, Contract Terminations and Discontinued Operations—GEN-WE Discontinued Operations—CoGen Lyondell for further discussion of the sale of CoGen Lyondell and Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—Rolling Hills for further discussion of the sale of Rolling Hills. Changes in the carrying amount of goodwill during the years ended December 31, 2008 and 2007 were as follows:

	GEN-MW	GEN-WE	GEN-NE	Total
		(in millions)		
December 31,2006	$—	$—	$—	$—
Acquisition of the Contributed Entities	81	308	97	486
Sale of CoGen Lyondell	—	(48)	—	(48)
December 31,2007	$ 81	$260	$ 97	$438
Sale of Rolling Hills	(5)	—	—	(5)
December 31, 2008	$ 76	$260	$ 97	$433

Goodwill is reviewed for potential impairment as of November 1st of each year or more frequently if events or circumstances occur that would indicate a reduction in our fair value. The impairment test is performed in two phases at the reporting unit level. The first step compares the fair value of the reporting unit with its carrying amount, including goodwill. We generally determine the fair value of our reporting units using the income approach. This analysis requires us to make various judgmental estimates and assumptions about sales, operating margins, growth rates, discount factors and comparable company market multiples. If the fair value of the reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered impaired; thus the second step of the goodwill impairment test is unnecessary. However, if the carrying amount of the reporting unit exceeds its fair value, an additional step is required. The additional step compares the implied fair value of the reporting unit's goodwill with the carrying amount of such goodwill. An impairment loss is recorded to the extent that the carrying value of the goodwill exceeds its implied fair value.

In evaluating our goodwill for impairment, we calculated the estimated fair value of our reporting units using a discounted cash flow analysis using forward-looking projections of our estimated future operating results based on discrete financial forecasts developed by management for planning purposes. Cash flows beyond the discrete forecasts were estimated using a terminal value calculation, which incorporated historical and forecasted financial trends and considered long-term earnings growth rates based on growth rates observed in the power sector. Next, we utilized 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. Based on the results of our analysis, we have concluded that the fair value of our reporting units exceeded their carrying values at November 1, 2008. Accordingly, we have determined that no goodwill impairment is indicated for 2008. Given the current economic environment, we will continue to monitor the need to test goodwill for impairment as required by SFAS No. 142.

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 share price does not reflect a control premium; (ii) 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, and (iii) our share price was negatively impacted in the third and fourth quarters of 2008 by the sale of large blocks of shares by hedge funds. After giving consideration to these factors, we concluded that our market capitalization at November 1, 2008 is not indicative of the fair value of our aggregate reporting units. Due to further declines in our market capitalization through December 31, 2008, we evaluated key assumptions, including forward natural gas and power pricing, power demand growth and cost of capital, to determine whether these assumptions remained valid at December 31, 2008. 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 units to be below their respective carrying values at December 31, 2008.

As with many financial statement matters, our impairment analysis requires us to make estimates and assumptions and make judgments that affect our conclusions and the reported financial information. Such estimates, assumptions and judgments are subject to known and unknown risks and uncertainties. Actual results could differ materially from those estimates and assumptions.

Note 14—Intangible Assets

A summary of changes in our intangible assets is as follows:

	LS Power	Sithe	Rocky Road	Total
		(in millions)		
December 31, 2005	$—	$442	$—	$442
Acquisition of Rocky Road	—	—	29	29
Amortization expense	—	(59)	(7)	(66)
December 31, 2006	$—	$383	$ 22	$405
Acquisition of the Contributed Entities	224	—	—	224
Amortization expense	(8)	(50)	(9)	(67)
December 31, 2007	$216	$333	$ 13	$562
Amortization expense	(7)	(49)	(9)	(65)
December 31, 2008	$209	$284	$ 4	$497

LS Power. Pursuant to our acquisition of the Contributed Entities in April 2007, we recorded intangible assets of $224 million. This consisted of intangible assets of $192 million in GEN-MW and $32 million in GEN-WE. The intangible asset in GEN-MW relates to the value of PPEA's interest in the Plum Point Project as a result of the construction contracts, debt agreements and related to power purchase agreements. This intangible asset will be amortized over the contractual term of 30 years, beginning when the facility becomes operational, which we expect to occur in 2010. The intangible assets for GEN-WE primarily relate to power tolling agreements that are being amortized over their respective contract terms ranging from 6 months to 7 years. The amortization expense is being recognized on the revenue line in our consolidated statements of operations where we record the revenues received from the contract.

The estimated amortization expense for each of the five succeeding years is approximately $7 million, $10 million, $6 million, $6 million and $6 million, respectively. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for further discussion.

Sithe. Pursuant to our acquisition of Sithe Energies in February 2005, we recorded intangible assets of $657 million. This consisted primarily of a $488 million intangible asset related to a firm capacity sales agreement between Sithe Independence Power Partners and Con Edison, a subsidiary of Consolidated Edison, Inc. That contract provides Independence the right to sell 740 MW of capacity until 2014 at fixed prices that are currently above the prevailing market price of capacity for the New York Rest of State market. This asset will be amortized on a straight-line basis over the remaining life of the contract through October 2014. The amortization expense is being recognized in the revenue line on our consolidated statements of operations where we record the revenues received from the contract. The annual amortization of the intangible asset is expected to approximate $50 million.

Rocky Road. Pursuant to our acquisition of NRG's 50 percent ownership interest in the Rocky Road power plant, we recorded an intangible asset in the amount of $29 million. The amortization expense associated with this asset is being recognized in the revenue line on our consolidated statements of operations where we record the revenues received from the contract. The annual amortization of the intangible asset is expected to be approximately $4 million in 2009. Please read Note 3—Business Combinations and Acquisitions—Rocky Road for further discussion.

Note 15—Debt

A summary of our long-term debt is as follows:

	December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Term Loan B, due 2013	$ 69	$ 52	$ 70	$ 70
Term Facility, floating rate due 2013	850	639	850	850
Senior Notes and Debentures:				
6.875 percent due 2011	502	427	502	483
8.75 percent due 2012	501	426	501	506
7.5 percent due 2015	550	388	550	514
8.375 percent due 2016	1,047	742	1,047	1,022
7.125 percent due 2018	173	110	173	155
7.75 percent due 2019	1,100	762	1,100	1,011
7.625 percent due 2026	172	93	172	149
Subordinated Debentures payable to affiliates, 8.316 percent, due 2027	200	83	200	173
Sithe Senior Notes, 9.0 percent due 2013	344	328	388	416
Plum Point Credit Agreement Facility, floating rate due 2010	515	365	318	318
Plum Point Tax Exempt Bonds, floating rate due 2036	100	100	100	100
	6,123		5,971	
Unamortized premium on debt, net	13		19	
	6,136		5,990	
Less: Amounts due within one year, including non-cash amortization of basis adjustments	64		51	
Total Long-Term Debt	$6,072		$5,939	

Aggregate maturities of the principal amounts of all long-term indebtedness as of December 31, 2008 are as follows: 2010—$68 million, 2011—$575 million, 2012—$582 million, 2013—$1,004 million and thereafter—$3,843 million.

Fifth Amended and Restated Credit Facility. On April 2, 2007, we entered into a fifth amended and restated credit facility (the "Fifth Amended and Restated Credit Facility") with Citicorp USA, Inc. and JPMorgan Chase Bank, N.A., as co-administrative agents, JPMorgan Chase Bank, N.A., as collateral agent, Citicorp USA Inc., as payment agent, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as joint lead arrangers and joint book-runners, and the other financial institutions party thereto as lenders or letter of credit issuers.

The Fifth Amended and Restated Credit Facility amended DHI's former credit facility by increasing the amount of the existing $470 million revolving credit facility (the "Revolving Facility") to $850 million, increasing the amount of the existing $200 million term letter of credit facility (the "Term L/C Facility") to $400 million and adding a $70 million senior secured term loan facility ("Term Loan B").

Loans and letters of credit are available under the Revolving Facility and letters of credit are available under the Term L/C Facility for general corporate purposes. Letters of credit issued under DHI's former credit facility have been continued under the Fifth Amended and Restated Credit Facility. The Term Loan B was used to pay a portion of the consideration under the Merger. In connection with the completion of the Merger, an aggregate $275 million under the Revolving Facility, an aggregate $400 million under the Term L/C Facility (with the proceeds placed in a collateral account to support the issuance of letters of credit), and an aggregate $70 million under Term Loan B (representing all available borrowings under Term Loan B) were drawn.

The Fifth Amended and Restated Credit Facility is secured by certain assets of DHI and is guaranteed by Dynegy, Dynegy Illinois and certain subsidiaries of DHI. In addition, the obligations under the Fifth Amended and Restated Credit Facility and certain other obligations to the lenders thereunder and their affiliates are secured by substantially all of the assets of such guarantors. The Revolving Facility matures on April 2, 2012, and the Term L/C Facility and Term Loan B each mature on April 2, 2013. The principal amount of the Term L/C Facility is due in a single payment at maturity; the principal amount of Term Loan B is due in quarterly installments of $175,000 in arrears commencing December 31, 2008, with the unpaid balance due at maturity.

Borrowings under the Fifth Amended and Restated Credit Facility bear interest, at DHI's option, at either the base rate, which is calculated as the higher of Citibank, N.A.'s publicly announced base rate and the federal funds rate in effect from time to time, or the Eurodollar rate (which is based on rates in the London interbank Eurodollar market), in each case plus an applicable margin.

The applicable margin for borrowings under the Fifth Amended and Restated Credit Facility depends on the Standard & Poor's Ratings Services ("S&P") and Moody's Investors Service, Inc. ("Moody's") credit ratings of the Fifth Amended and Restated Credit Facility, with higher credit ratings resulting in a lower rate. The applicable margin for such borrowings will be either 0.125 percent or 0.50 percent per annum for base rate loans and either 1.125 percent or 1.50 percent per annum for Eurodollar loans, with the lower applicable margin being payable if the ratings for the Fifth Amended and Restated Credit Facility by S&P and Moody's are BB+ and Ba1 or higher, respectively, and the higher applicable margin being payable if such ratings are less than BB+ and Ba1.

An unused commitment fee of either 0.25 percent or 0.375 percent is payable on the unused portion of the Revolving Facility, with the lower commitment fee being payable if the ratings for the Revolving Facility by S&P and Moody's are BB+ and Ba1 or higher, respectively, and the higher commitment fee being payable if such ratings are less than BB+ and Ba1.

The Fifth Amended and Restated Credit Facility contains mandatory prepayment provisions associated with specified asset sales and dispositions (including as a result of casualty or condemnation). The Fifth Amended and Restated Credit Facility also contains customary affirmative and negative non-financial covenants and events of default. Subject to certain exceptions, DHI and its subsidiaries are subject to restrictions on incurring additional indebtedness, limitations on investments and certain limitations on dividends and other payments in respect of capital stock.

The Fifth Amended and Restated Credit Facility also 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 earnings before interest, taxes, depreciation and amortization ("EBITDA") for DHI and its relevant subsidiaries of no greater than 2.75:1 (December 31, 2008 and thereafter through and including 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 period 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.

On May 24, 2007, we entered into an Amendment No. 1, dated as of May 24, 2007 (the "Amendment No.1"), to the Fifth Amended and Restated Credit Facility, which increased the amount of the existing $850 million Revolving Facility to $1.15 billion and increased the amount of the existing $400 million Term L/C Facility to $850 million; the Amendment No. 1 did not affect the Term Loan B. The Amendment No. 1 also amended a pro forma leverage ratio requirement in the Fifth Amended and Restated Credit Facility to allow DHI to issue the Notes (as defined and discussed below).

In September 2008, Lehman Brothers Holding Inc. filed for protection from creditors under Chapter 11 bankruptcy law. Lehman Commercial Paper Inc. ("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. Lehman CP is now formally a defaulting lender under our Fifth Amended and Restated Credit Facility, is no longer accruing commitment fees and would not be expected to fund any borrowing requests, thereby reducing our effective availability under the Fifth Amended and Restated Credit Facility by $70 million to $1.9 billion.

On September 30, 2008, we entered into Amendment No. 2 ("Amendment No. 2") to the Fifth Amended and Restated Credit Facility. Amendment No. 2 serves to amend the definition of "Change of Control" in Section 1.01 of our Fifth Amended and Restated Credit Facility such that the reference to "42%" was replaced with "50%".

On February 13, 2009, we entered into Amendment No. 3 ("Amendment No. 3") to the Fifth Amended and Restated Credit Facility. Amendment No. 3 relates to the modification of certain conditions precedent to refinancing of existing indebtedness, the incurrence of other DHI indebtedness, adding revolver commitments, certain investments, asset sales and certain other events. Prior to Amendment No. 3, such conditions precedent included satisfaction, on a pro forma basis, of a separate ratio test of total indebtedness divided by EBITDA (both as defined in the Fifth Amended and Restated Credit Facility) of not greater than 5.0:1. Amendment No. 3 changes the ratio test to not greater than 6.0:1 for 2009. For years 2010 and thereafter, such ratio test will revert to the 5.0:1 level.

Senior Notes. On April 12, 2006, DHI issued $750 million aggregate principal amount of our 8.375 percent Senior Unsecured Notes due 2016 (the "New Senior Notes") in a private offering (the "Senior Notes Offering"). The New Senior Notes are not redeemable at our option prior to maturity. The New Senior Notes are our senior unsecured obligations of DHI and rank equal in right of payment to all of DHI's existing and future senior unsecured indebtedness, and are senior to all of our existing and any of our future subordinated indebtedness. Dynegy did not guarantee the New Senior Notes, and the assets that Dynegy owns (principally its interest in DLS Power Holdings and DLS Power Development) do not support the New Senior Notes. The proceeds from the Senior Notes Offering, together with cash on hand, were used to fund the SPN Tender Offer discussed below. On September 14, 2006, DHI exchanged the New Senior Notes for a new issue of substantially identical notes registered under the Securities Act of 1933.

On May 24, 2007, DHI issued $1.1 billion aggregate principal amount of its 7.75 percent Senior Unsecured Notes due 2019 (the "2019 Notes") and $550 million aggregate principal amount of its 7.50 percent Senior Unsecured Notes due 2015 (the "2015 Notes" and, together with the 2019 Notes, the "Notes") pursuant to the terms of a purchase agreement, dated as of May 17, 2007, by and among DHI and the several initial purchasers party thereto (the "Purchasers"). The Notes are senior unsecured obligations and rank equal in right of payment to all of DHI's existing and future senior unsecured indebtedness, and are senior to all of DHI's existing, and any of its future, subordinated indebtedness. DHI's secured debt and its other secured obligations are effectively senior to the Notes to the extent of the value of the assets securing such debt or other obligations. None of DHI's subsidiaries have guaranteed the Notes and, as a result, all of the existing and future liabilities of DHI's subsidiaries are effectively senior to the Notes. Dynegy has not guaranteed the Notes, and the assets that Dynegy owns through its subsidiaries, other than DHI, do not support the Notes. In connection with the Notes, DHI entered into a registration rights agreement with the Purchasers of the Notes pursuant to which DHI agreed to offer to exchange the Notes for a new issue of substantially identical notes registered under the Securities Act of 1933. On October 15, 2007, pursuant to the registration rights agreement, DHI initiated the exchange offer, which was completed in the fourth quarter 2007.

DHI used the net proceeds from the sale of the Notes to repay a portion of the debt assumed in the Merger. Long-term debt assumed upon completion of the Merger and repaid from the proceeds of the sale of the Notes consisted of the following as of April 2, 2007:

	Face Value	Premium Discount	Fair Value
		(in millions)	
Generation Facilities First Lien Term Loans due 2013	$ 919	$ 1	$ 920
Generation Facilities Second Lien Term Loans due 2014	150	1	151
Kendall First Lien Term Loan due 2013	396	(5)	391
Ontelaunee First Lien Term Loan due 2009	100	(1)	99
Ontelaunee Second Lien Credit Agreement due 2009	50	1	51
Total debt repaid with proceeds from unsecured offering	$1,615	$(3)	$1,612

Outstanding letters of credit under the above mentioned LC facilities were transferred to, and became outstanding letters of credit under, the Fifth Amended and Restated Credit Facility as amended. Continuing secured obligations of Dynegy Gen Finance Co LLC include financially settled heat rate options and a collateral posting arrangement that are secured by the assets of Dynegy Gen Finance Co LLC.

Second Priority Senior Secured Notes. On April 12, 2006, we completed a cash tender offer and consent solicitation (the "SPN Tender Offer"), in which we purchased $151 million of our $225 million Second Priority

Senior Secured Floating Rate Notes due 2008 (the "2008 Notes"), $614 million of our $625 million 9.875 percent Second Priority Senior Secured Notes due 2010 (the "2010 Notes") and all $900 million of our 10.125 percent Second Priority Senior Secured Notes due 2013 (the "2013 Notes" and collectively with the "2008 Notes" and the "2010 Notes," the "Second Priority Notes"). In connection with the SPN Tender Offer, we amended the indenture under which the Second Priority Notes were issued to eliminate or modify substantially all of the restrictive covenants, certain events of default and related provisions and release certain liens securing the obligations of DHI and the guarantors of the Second Priority Notes.

Total cash paid to repurchase the $1,664 million of Second Priority Notes, including consent fees and accrued interest, was $1,904 million. We recorded a charge of approximately $228 million in 2006 associated with this transaction, of which $202 million is included in debt conversion costs, and $26 million of acceleration of amortization of financing costs and write-offs of discounts and premiums is included in interest expense on our consolidated statements of operations.

On July 15, 2006, we redeemed the remaining $74 million of our 2008 Notes, at a redemption price of 103 percent of the principal amount, plus accrued and unpaid interest to the redemption date. The interest rate on the 2008 Notes was based on three-month LIBOR plus 650 basis points. We recorded a charge of approximately $2 million in 2006 associated with this transaction, which is included in debt conversion costs in our consolidated statements of operations.

On September 7, 2007, we completed the redemption of $11 million of DHI's remaining outstanding 2010 Notes at a redemption price of 104.938 percent of the principal amount plus accrued and unpaid interest to the date of redemption.

Subordinated Debentures. In May 1997, NGC Corporation Capital Trust I ("Trust") issued, in a private transaction, $200 million aggregate liquidation amount of 8.316 percent Subordinated Capital Income Securities ("Trust Securities") representing preferred undivided beneficial interests in the assets of the Trust. The Trust invested the proceeds from the issuance of the Trust Securities in an equivalent amount of DHI's 8.316 percent Subordinated Debentures ("Subordinated Debentures"). The sole assets of the Trust are the Subordinated Debentures. The Trust Securities are subject to mandatory redemption in whole, but not in part, on June 1, 2027, upon payment of the Subordinated Debentures at maturity, or in whole, but not in part, at any time, contemporaneously with the optional prepayment of the Subordinated Debentures, as allowed by the associated indenture. The Subordinated Debentures are redeemable, at DHI's option, at specified redemption prices. The Subordinated Debentures represent DHI's unsecured obligations and rank subordinate and junior in right of payment to all of DHI's senior indebtedness to the extent and in the manner set forth in the associated indenture. We have irrevocably and unconditionally guaranteed, on a subordinated basis, payment for the benefit of the holders of the Trust Securities the obligations of the Trust to the extent the Trust has funds legally available for distribution to the holders of the Trust Securities. Since the Trust is considered a VIE, and the holders of the Trust Securities absorb a majority of the Trust's expected losses, DHI's obligation is represented by the Subordinated Debentures payable to the deconsolidated Trust. We may defer payment of interest on the Subordinated Debentures as described in the indenture, although we have not yet done so and have continued to pay interest as and when due. As of December 31, 2008 and 2007, the redemption amount associated with these securities totaled $200 million.

Contingent LC Facility. On June 17, 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.

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.

Sithe Senior Notes. On January 31, 2005, we completed the acquisition of ExRes, the parent company of Sithe Energies and Independence. Upon the closing, we consolidated $919 million in face value project debt, which was recorded at its fair value of $797 million as of January 31, 2005, for which certain of the entities acquired are obligated. Please read Note 3—Business Combinations and Acquisitions—Sithe Energies Business Combination for further discussion of this transaction.

Long-term debt consolidated upon completion of the Sithe Energies acquisition consisted of the following as of January 31, 2005:

	Face Value	Premium (Discount)	Fair Value
		(in millions)	
Subordinated Debt, 7.0 percent due 2034	$419	$(167)	$252
Senior Notes, 8.5 percent due 2007	91	3	94
Senior Notes, 9.0 percent due 2013	409	42	451
Total Independence Debt	$919	$(122)	$797

The senior debt and subordinated debt are secured by substantially all of the assets of Independence, but are not guaranteed by us. The difference of $122 million between the face value and the fair value of the Independence Debt that was recognized upon the acquisition of ExRes will be accreted into interest expense over the life of the debt.

The terms of the indenture governing the senior debt, among other things, prohibit cash distributions by Independence to its affiliates, including Dynegy, unless certain project reserve accounts are funded to specified levels and the required debt service coverage ratio is met. The indenture also includes other covenants and restrictions, relating to, among other things, prohibitions on asset dispositions and fundamental changes, reporting requirements and maintenance of insurance.

On July 21, 2006, DHI executed and consummated an exchange agreement (the "Exchange Agreement"), by and among DHI and RCP Debt, LLC and RCMF Debt, LLC (together, the "Reservoir Entities"). Pursuant to the Exchange Agreement, the Reservoir Entities exchanged approximately $419 million principal amount of the subordinated debt of Independence, together with all claims for accrued and unpaid interest thereon and all other rights and all obligations of the Reservoir Entities under the agreement pursuant to which the subordinated debt was issued (together, the "Sithe Debt"), for approximately $297 million principal amount of DHI's 8.375 percent Senior Unsecured Notes due 2016 (the "Additional Notes"). The Additional Notes have terms and conditions identical to, and are fungible for trading and other purposes with, the $750 million aggregate principal amount of the New Senior Notes issued on April 12, 2006. On September 14, 2006, DHI exchanged the Additional Notes for a new issue of substantially identical notes registered under the Securities Act of 1933. We recorded a charge of approximately $36 million in 2006 associated with this transaction, which is included in interest expense in our consolidated statements of operations.

Plum Point Credit Agreement Facility. The Plum Point Credit Agreement Facility ("Credit Agreement Facility") consists of a $700 million construction loan (the "Construction Loan"), a $700 million term loan commitment (the "Bank Loan"), a $17 million revolving credit facility (the "Revolver") and a $102 million backstop letter of credit facility (the "LC Facility"). The LC Facility was initially utilized to back-up the $101 million letter of credit issued under the then-existing LC Facility (the "Original LC") for the benefit of the owners of the Tax Exempt Bonds described below. During the second quarter 2007, the Tax Exempt Bonds were repaid and reoffered and a new letter of credit in the amount of approximately $101 million was issued under the LC Facility in substitution for the Original LC. Borrowings under the Credit Agreement Facility bear interest, at Plum Point's option, at either the base rate, which is determined as the greater of the Prime Rate or the Federal Funds Rate in effect from time to time plus ½ of 1 percent, or Adjusted LIBOR, which is equal to the product of the applicable LIBOR and any Statutory Reserves plus an applicable margin equal to 0.35 percent. In addition, Plum Point pays commitment fees equal to 0.125 percent per annum on the undrawn Bank Loan, Revolver and LC Facility commitments. Upon completion of the construction of the Plum Point Project, the Construction Loan will terminate and the debt thereunder will be replaced by the Bank Loan. The Bank Loan matures on the thirtieth anniversary of the later of the date on which substantial completion of the facility has occurred or the first date of commercial operation under any of the power purchase agreements then in effect. The expected commercial operations date is August 2010.

The payment obligations of Plum Point in respect of the Bank Loan, the Revolver, the LC Facility, and associated interest rate hedging agreements (discussed below) are unconditionally and irrevocably guaranteed by Ambac Assurance Corporation. Ambac Assurance Corporation also provided an unconditional commitment to issue, upon the closing of any refinancing of the Tax Exempt Bonds, a bond insurance policy insuring the Tax Exempt Bonds and a debt service reserve surety in an amount equal to the debt service reserve requirement with respect to such bonds. The credit facilities and insurance policy are secured by a mortgage and security interest (subject to permitted liens) in all of Plum Point's assets and contract rights and Plum Point's undivided tenancy in common interest in the Plum Point Project and PPEA's interest in Plum Point. Plum Point pays an additional 0.38 percent spread for the AMBAC insurance coverage, which is deemed a cost of financing and included in interest expense.

In the second quarter 2007, Plum Point entered into three interest rate swap agreements with an initial aggregate notional amount of approximately $183 million and fixed interest rates of approximately 5.3 percent. These interest rate swap agreements convert Plum Point's floating rate debt exposure (exclusive of that on the Tax Exempt Bonds) to a fixed interest rate. The interest rate swap agreements expire in June 2040. During 2007, we recorded $27 million of mark-to-market income related to these interest rate swap agreements as an offset to our consolidated interest expense. Effective July 1, 2007, we designated these agreements as cash flow hedges. Therefore, changes in value after that date are reflected in Other Comprehensive Income (Loss), and subsequently reclassified to interest expense contemporaneously with the related interest expense, or depreciation expense in the event the interest was capitalized, in either case to the extent of hedge effectiveness.

Plum Point Tax Exempt Bonds. On April 1, 2006, the City of Osceola (the "City") loaned the $100 million in proceeds of a tax exempt bond issuance (the "Tax Exempt Bonds") to Plum Point. The Tax Exempt Bonds were issued pursuant to and secured by a Trust Indenture dated April 1, 2006 between the City and Regions Bank as Trustee. The purpose of the Tax Exempt Bonds is to finance certain of Plum Point's undivided interests in various sewage and solid waste collection and disposal facilities in the Plum Point facility. Interest expense on the Tax Exempt Bonds is based on a weekly variable rate and is payable monthly. The interest rate in effect at December 31, 2008 was 3.50 percent. The Tax Exempt Bonds mature on April 1, 2036.

Convertible Subordinated Debentures due 2023. On May 15, 2006, we converted all $225 million of our outstanding 4.75 percent Convertible Subordinated Debentures due 2023 into shares of our Class A common stock (the "Convertible Debenture Exchange"). In this transaction, we issued an aggregate of 54,598,369 shares of our Class A common stock and paid the debenture holders an aggregate of approximately $47 million in premiums and accrued and unpaid interest using cash on hand. We recorded a charge of approximately $44 million in 2006 associated with this transaction, which is included in debt conversion costs in our consolidated statements of operations.

Restricted Cash and Investments. The following table depicts our restricted cash and investments as of December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
	(in millions)	
Credit facility (1)	$ 850	$ 850
Sithe Energy (2)	41	41
Plum Point (3)	29	54
GEN Finance (4)	50	57
Sandy Creek (5)	275	323
Total restricted cash and investments	$1,245	$1,325

(1) Includes cash posted to support the letter of credit component of our credit facility. We are required to post cash collateral in an amount equal to 103 percent of outstanding letters of credit.
(2) Includes amounts related to the terms of the indenture governing the Sithe Senior Debt, which among other things, prohibit cash distributions by Independence to its affiliates, including us, unless certain project reserve accounts are funded to specified levels and the required debt service coverage ratio is met.
(3) Includes proceeds from the Tax Exempt Bonds. These funds are used to finance PPEA's undivided interest in various sewage and solid waste collection and disposal facilities which are under construction. Funds will be drawn from the restricted accounts as necessary for the construction of these facilities.
(4) Includes amounts restricted under the terms of a security and deposit agreement associated with a collateral agreement and commodity hedges entered into by GEN Finance.
(5) Includes amounts related to our funding commitment related to the Sandy Creek Project. Please read Note 12—Variable Interest Entities—Sandy Creek.

Note 16—Related Party Transactions

Transactions with Chevron

On April 2, 2007, in connection with the Merger, the ownership interest of Chevron U.S.A. Inc. ("CUSA") was reduced from approximately 20 percent to approximately 12 percent and CUSA's shares automatically converted into Class A shares. On May 24, 2007, CUSA completed the sale of its 96,891,014 shares of Dynegy's Class A common stock in an underwritten public offering.

Transactions with CUSA consisted of purchases and sales of natural gas and natural gas liquids between our affiliates and CUSA. We believe that these transactions were executed on terms that were fair and reasonable. During the years ended December 31, 2007 and 2006, we recognized net purchases from CUSA of $22 million and $52 million, respectively. In accordance with the net presentation provisions of EITF Issue 02-3, all of these transactions, whether physically or financially settled, have been presented net on the consolidated statements of operations.

Series C Convertible Preferred Stock. In August 2003, Dynegy issued to CUSA 8 million shares of its Series C Convertible Preferred Stock due 2033 ("Series C Preferred"). Dynegy accrued dividends on the Series C Preferred at a rate of 5.5 percent of the liquidation value per annum. In May 2006, Dynegy redeemed all of the outstanding shares of its Series C Preferred, which were held by CUSA. In order to redeem the Series C Preferred, Dynegy paid CUSA $400 million in cash, plus accrued and unpaid dividends totaling approximately $6.3 million. Dynegy used approximately $178 million in net proceeds from an equity offering of 40.25 million shares of its Class A common stock that closed on the same day (including net proceeds of $23 million from the underwriters' exercise of their option to purchase an additional 5.25 million shares), with the balance funded from cash on hand and a cash dividend of $50 million from DHI. The redemption of the Series C Preferred eliminated the associated $22 million annual preferred dividend and reduced the number of diluted shares of Dynegy's common stock outstanding.

Equity Investments. We hold an investment in a joint venture in which CUSA or its affiliates are also investors. The investment is a 50 percent ownership interest in Black Mountain, which owns the Black Mountain power generation facility. During the years ended December 31, 2008, 2007 and 2006, our portion of the net income from joint ventures with CUSA was approximately $1 million, $7 million and $8 million, respectively.

Other

Equity Investments. We also hold three investments in joint ventures in which LS Power or its affiliates are also investors. Dynegy has a 50 percent ownership interest in DLS Power Holdings and DLS Power Development. DHI has a 50 percent ownership interest in SCEA, which was contributed to it by Dynegy in August 2007. Effective January 1, 2009, Dynegy and LS Power Associates, L.P. agreed to dissolve the two companies' development joint venture. Please read Note 12—Variable Interest Entities for further discussion.

December 2001 Equity Purchases. In December 2001, ten former members of our senior management purchased Class A common stock from Dynegy in a private placement pursuant to Section 4(2) of the Securities Act of 1933. These former officers received loans from Dynegy totaling approximately $25 million to purchase Dynegy's common stock at a price of $19.75 per share, the same price as the net proceeds per share received by Dynegy from a concurrent public offering. The loans bear interest at 3.25 percent per annum and are full recourse to the borrowers. Such loans are accounted for as subscriptions receivable within Dynegy's stockholders' equity on the consolidated balance sheets.

Other. DHI paid dividends of $342 million to Dynegy for the year ended December 31, 2007. Additionally, DHI paid a dividend of $175 million to Dynegy in January, 2009.

On April 2, 2007, Dynegy contributed to Dynegy Illinois its interest in the Contributed Entities. Also in April 2007, Dynegy Illinois contributed to DHI all of its interest in New York Holdings, together with its indirect interest in the subsidiaries of New York Holdings. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for further discussion. In August 2007, Dynegy contributed to DHI its 50 percent interest in SCH. Please read Note 12—Variable Interest Entities—Sandy Creek for further information.

During 2006, DHI repaid a $120 million borrowing from Dynegy. Also during 2006, DHI made a one time dividend payment of $50 million to Dynegy from the proceeds of the Term Loan. Please read Note 15—Debt for further discussion.

In the normal course of business, payments are made or cash is received by DHI on behalf of Dynegy, or by Dynegy on behalf of DHI. As a result of such transactions, DHI has recorded over time a receivable from Dynegy in the aggregate amount of $827 million and $825 million at December 31, 2008 and 2007, respectively. DHI resolved, effective December 31, 2007, to memorialize and distribute this receivable balance to Dynegy, once all required third-party approvals have been obtained. As such, this receivable is classified as equity on DHI's consolidated balance sheet as of December 31, 2008 and 2007.

Note 17—Income Taxes

Income Tax (Expense) Benefit-Dynegy. We are subject to U.S. federal, foreign and state income taxes on our operations.

Dynegy's components of income (loss) from continuing operations before income taxes were as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Income (loss) from continuing operations before income taxes:			
Domestic	$218	$273	$(478)
Foreign	28	(6)	5
	$246	$267	$(473)

Dynegy's components of income tax (expense) benefit related to income (loss) from continuing operations were as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Current tax expense:			
Domestic	$ (5)	$ (22)	$ (3)
Foreign	—	—	(2)
Deferred tax benefit (expense):			
Domestic	(66)	(132)	148
Foreign	(4)	3	9
Income tax (expense) benefit	$ (75)	$(151)	$152

Dynegy's income tax (expense) benefit related to income (loss) from continuing operations for the years ended December 31, 2008, 2007 and 2006, was equivalent to effective rates of 30 percent, 57 percent and 32 percent, respectively. Differences between taxes computed at the U.S. federal statutory rate and Dynegy's reported income tax benefit were as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Expected tax (expense) benefit at U.S. statutory rate (35%)	$ (86)	$ (94)	$166
State taxes (1)	—	(55)	32
Foreign taxes	—	5	(12)
Permanent differences	7	(2)	3
Valuation allowance	(6)	—	(4)
IRS and state audits and settlements	—	(3)	(38)
Other (2)	10	(2)	5
Income tax (expense) benefit	$ (75)	$(151)	$152

(1) Includes a benefit of $18 million and expense of $21 million for the years ended December 31, 2008 and 2007, respectively, related to adjustments arising from measurement of temporary differences.

(2) Includes a benefit of $8 million for the year ended December 31, 2008 arising from the conversion of a foreign tax credit to a deduction.

Income Tax (Expense) Benefit-DHI. DHI's components of income (loss) from continuing operations before income taxes were as follows:

	Year Ended December 31, 2008	2007	2006
	(in millions)		
Income (loss) from continuing operations before income taxes:			
Domestic	$300	$298	$(426)
Foreign	28	(6)	5
	$328	$292	$(421)

DHI's components of income tax benefit related to loss from continuing operations were as follows:

	Year Ended December 31, 2008	2007	2006
	(in millions)		
Current tax benefit (expense):			
Domestic	$ (3)	$ (11)	$ (1)
Foreign	—	—	(2)
Deferred tax benefit (expense):			
Domestic	(116)	(108)	119
Foreign	(4)	3	9
Income tax (expense) benefit	$(123)	$(116)	$125

DHI's income tax (expense) benefit related to income (loss) from continuing operations for the years ended December 31, 2008, 2007 and 2006, was equivalent to effective rates of 38 percent, 40 percent and 30 percent, respectively. Differences between taxes computed at the U.S. federal statutory rate and DHI's reported income tax benefit were as follows:

	Year Ended December 31, 2008	2007	2006
	(in millions)		
Expected tax benefit at U.S. statutory rate (35%)	$(115)	$(102)	$147
State taxes (1)	(14)	(21)	17
Foreign taxes	—	5	(12)
Permanent Differences	7	(2)	5
Valuation allowance	(6)	—	(4)
IRS and state audits and settlements	—	8	(38)
Other (2)	5	(4)	10
Income tax (expense) benefit	$(123)	$(116)	$125

(1) Includes a benefit of $12 million and expense of $19 million for the years ended December 31, 2008 and 2007, respectively, related to adjustments arising from measurement of temporary differences.

(2) Includes a benefit of $8 million for the year ended December 31, 2008 arising from the conversion of a foreign tax credit to a deduction.

Deferred Tax Liabilities and Assets. Our significant components of deferred tax assets and liabilities were as follows:

	Dynegy		DHI	
	Year Ended December 31,		Year Ended December 31,	
	2008	2007	2008	2007
	(in millions)			
Deferred tax assets:				
Current:				
Reserves (legal, environmental and other)	$ —	$ 28	$ —	$ 28
NOL carryforwards	13	58	12	48
Miscellaneous book/tax recognition differences	4	—	4	—
Subtotal	17	86	16	76
Less: valuation allowance	(5)	(18)	(5)	(16)
Total current deferred tax assets	12	68	11	60
Non-current:				
NOL carryforwards	35	97	35	86
AMT credit carryforwards	271	262	—	—
Capital loss carryforward	10	17	10	17
Foreign tax credits	—	24	—	21
Reserves (legal, environmental and other)	42	53	42	53
Other comprehensive income	146	30	146	30
Miscellaneous book/tax recognition differences	71	30	47	26
Subtotal	575	513	280	233
Less: valuation allowance	(32)	(44)	(32)	(43)
Total non-current deferred tax assets	543	469	248	190
Deferred tax liabilities:				
Current:				
Reserves (legal, environmental and other)	6	—	8	—
Miscellaneous book/tax recognition differences	—	23	—	30
Total current deferred tax liabilities	6	23	8	30
Non-current:				
Depreciation and other property differences	1,620	1,640	1,207	1,184
Power contract	89	75	93	54
Total non-current deferred tax liabilities	1,709	1,715	1,300	1,238
Net deferred tax liability	$1,160	$1,201	$1,049	$1,018

NOL Carryforwards-Dynegy. At December 31, 2008, Dynegy had approximately $32 million of regular federal tax NOL carryforwards and $1 billion of AMT NOL carryforwards. The federal and AMT NOL carryforwards will expire beginning in 2027 and 2024, respectively. As a result of the application of certain provisions of the Internal Revenue Code, Dynegy incurred an ownership change in May 2007 that placed an annual limitation on its ability to utilize certain tax carryforwards, including its NOL carryforwards. We do not expect that the ownership change will have a material impact on Dynegy's tax liability. There was no valuation allowance established at December 31, 2008 for Dynegy's federal NOL carryforwards, as management believes Dynegy's NOL carryforward is more likely than not to be fully realized in the future based, among other things, on management's estimates of future taxable net income, future reversals of existing taxable temporary differences and tax planning.

At December 31, 2008 and 2007, state NOL carryforwards totaled $815 million and $1.3 billion, respectively. At December 31, 2008 and 2007, foreign NOL carryforwards totaled $4 million and $1 million, respectively.

NOL Carryforwards—DHI. At December 31, 2008, DHI had approximately $28 million of regular federal tax NOL carryforwards. The federal NOL carryforwards will expire beginning in 2027. As a result of the application of certain provisions of the Internal Revenue Code, Dynegy incurred an ownership change in May 2007 that placed an annual limitation on its ability to utilize certain tax carryforwards, including its NOL carryforwards. We do not expect that the ownership change will have a material impact on DHI's tax liability. There was no valuation allowance established at December 31, 2008 for DHI's federal NOL carryforwards, as management believes DHI's NOL carryforward is more likely than not to be fully realized in the future based, among other things, on management's estimates of future taxable net income, future reversals of existing taxable temporary differences and tax planning.

At December 31, 2008 and 2007, state NOL carryforwards totaled $815 million and $1.3 billion, respectively. At December 31, 2008 and 2007, foreign NOL carryforwards totaled $4 million and $1 million, respectively.

AMT Credit Carryforwards. At December 31, 2008, Dynegy had approximately $271 million of AMT credit carryforwards. The AMT credit carryforwards do not expire. As a result of the application of certain provisions of the internal revenue code, Dynegy incurred an ownership change on May 2007 that placed an annual limitation on its liability to utilize certain tax carryforwards, including its AMT credits. We do not expect that the ownership change will have a material impact on Dynegy's tax liability. There was no valuation allowance established at December 31, 2008 for Dynegy's AMT credit carryforwards, as management believes the AMT credit carryforward is more likely than not to be fully realized in the future based, among other things, on management's estimates of future taxable net income and future reversals of existing taxable temporary differences.

Capital Loss Carryforwards. At December 31, 2008, we had approximately $10 million of federal capital loss carryforwards. The capital loss carryforwards expire in 2009. At December 31, 2008, we had a full valuation allowance against our capital loss carryforwards, which management believes are not likely to be fully realized in the future based on our ability to generate capital gains.

Foreign Tax Credits. At December 31, 2008 and 2007, Dynegy had approximately zero and $24 million of foreign tax credits. The foreign tax credits, which had expiration dates between 2010 and 2016 were converted to a foreign tax deduction in 2008. In conjunction with the conversion, the associated $24 million valuation allowance was released and a tax benefit of $8 million was recognized.

At December 31, 2008 and 2007, DHI had approximately zero and $21 million of foreign tax credits. The foreign tax credits, which had expiration dates between 2010 and 2016, were converted to a foreign tax deduction in 2008. In conjunction with the conversion, the associated $21 million valuation allowance was released and a tax benefit of $8 million was recognized.

Residual U.S. Income Tax on Foreign Earnings. We do not have material undistributed non-previously taxed earnings from our foreign operations, and therefore, we have not provided any U.S. deferred taxes or foreign withholding taxes on the actual or deemed remittance of any such earnings.

Change in Valuation Allowance. Realization of our deferred tax assets is dependent upon, among other things, our ability to generate taxable income of the appropriate character in the future. At December 31, 2008, valuation allowances related to capital loss carryforwards, foreign NOL carryforwards, other foreign book-tax differences and state NOL carryforwards have been established. During 2008, we decreased our valuation allowance associated with capital loss carryforwards and foreign tax credits, and increased our valuation allowance on state NOL carryforwards, foreign NOL carryforwards, and foreign book-tax differences. During 2007, we decreased our valuation allowance associated with various state NOL carryforwards, and increased our valuation allowance on foreign tax credit carryforwards. During 2006, we increased our valuation allowance associated with various state NOL carryforwards and released a valuation allowance on foreign NOL carryforwards.

The changes in the valuation allowance by attribute for Dynegy were as follows:

	Capital Loss Carryforwards	Foreign Tax Credits	State NOL Carryforwards	Foreign NOL Carryforwards and Deferred Tax Assets	Total
			(in millions)		
Balance as of December 31, 2005	$(17)	$(23)	$(17)	$(13)	$(70)
Changes in valuation allowance—Sithe subordinated debt exchange	—	—	5	—	5
Changes in valuation allowance—continuing operations	—	—	(10)	13	3
Changes in valuation allowance—discontinued operations	—	—	(7)	—	(7)
Balance as of December 31, 2006	(17)	(23)	(29)	—	(69)
Changes in valuation allowance—continuing operations	—	—	6	—	6
Changes in valuation allowance—discontinued operations	—	(1)	2	—	1
Balance as of December 31, 2007	(17)	(24)	(21)	—	(62)
Changes in valuation allowance—continuing operations	—	8	(2)	(4)	2
Other release	7	16	—	—	23
Balance as of December 31, 2008	$(10)	$—	$(23)	$ (4)	$(37)

The changes in the valuation allowance by attribute for DHI were as follows:

	Capital Loss Carryforwards	Foreign Tax Credits	State NOL Carryforwards	Foreign NOL Carryforwards and Deferred Tax Assets	Total
			(in millions)		
Balance as of December 31, 2005	$ (17)	$ (5)	$ (17)	$ (13)	$(52)
Changes in valuation allowance—Sithe subordinated debt exchange	—	—	5	—	5
Changes in valuation allowance—continuing operations	—	(15)	(10)	13	(12)
Changes in valuation allowance—discontinued operations	—	—	(7)	—	(7)
Balance as of December 31, 2006	(17)	(20)	(29)	—	(66)
Changes in valuation allowance—continuing operations	—	—	6	—	6
Changes in valuation allowance—discontinued operations	—	(1)	2	—	1
Balance as of December 31, 2007	(17)	(21)	(21)	—	(59)
Changes in valuation allowance—continuing operations	—	8	(2)	(4)	2
Other release	7	13	—	—	20
Balance as of December 31, 2008	$ (10)	$—	$ (23)	$ (4)	$(37)

Acquisition of LS Power. On April 2, 2007, Dynegy acquired the Contributed Entities. Please read Note 3—Business Combinations and Acquisitions—LS Power for further discussion. As a part of this transaction, Dynegy recorded a net deferred tax liability of $627 million.

Unrecognized Tax Benefits. Dynegy files a consolidated income tax return in the U.S. federal jurisdiction, and we file other income tax returns in various states and foreign jurisdictions. DHI is included in Dynegy's consolidated federal tax returns. With few exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2004. Our federal income tax returns are routinely audited by the IRS, and provisions are routinely made in the financial statements in anticipation of the results of these audits. We have begun the IRS audit of our 2006-2007 tax years and expect to finalize our 2004-2005 audit in the first quarter 2009. As a result of the IRS Revenue Agent's Report for our 2004-2005 audit, a 2007 settlement of a Canadian audit, and various state settlements, we recorded, and included in our income tax expense, a benefit of $1 million and an expense of $8 million for the years ended December 31, 2008 and 2007, respectively.

Dynegy adopted the provisions of FIN No. 48 on January 1, 2007 and recorded a decrease of $7 million to its accumulated deficit as of January 1, 2007 to reflect the cumulative effect of adopting FIN No. 48. DHI adopted the provisions of FIN No. 48 on January 1, 2007 and recorded a decrease of $13 million to its accumulated deficit as of January 1, 2007 to reflect the cumulative effect of adopting FIN No. 48. Additionally, in conjunction with the adoption of FIN No. 48, as of January 1, 2007, Dynegy reduced its regular federal tax NOL carryforwards by $253 million, from $948 million to $695 million. The reduction was offset by corresponding changes to its net deferred tax liability and reserve for uncertain tax positions. DHI reduced its regular federal tax NOL carryforwards by $153 million, from $597 million to $444 million. The reduction was offset by corresponding changes to its net deferred tax liability and reserve for uncertain tax positions.

A reconciliation of Dynegy's and DHI's beginning and ending amounts of unrecognized tax benefits follows:

	Dynegy	DHI
	(in millions)	
Balance at January 1, 2007	$111	$ 77
Additions based on tax positions related to the current year	1	1
Additions based on tax positions related to the prior year	11	1
Reductions based on tax positions related to the prior year	(47)	(46)
Settlements	(43)	(25)
Balance at December 31, 2007	$ 33	$ 8
Additions based on tax positions related to the prior year	2	2
Reductions based on tax positions related to the prior year	(3)	(3)
Balance at December 31, 2008	$ 32	$ 7

As of December 31, 2008 and December 31, 2007, approximately $30 million and $31 million of unrecognized tax benefits would impact Dynegy's effective tax rate if recognized. As of December 31, 2008 and December 31, 2007, approximately $6 million and $6 million of unrecognized tax benefits would impact DHI's effective tax rate if recognized.

The changes to our unrecognized tax benefits during the twelve months ended December 31, 2008 primarily resulted from changes in various state audits and positions. The adjustments to our reserves for uncertain tax positions as a result of these changes had an insignificant impact on our net income.

Included in our balance of unrecognized tax benefits at December 31, 2008 is $2 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authorities to an earlier period.

During both the years ended December 31, 2008 and 2007, we recognized less than $1 million in interest and penalties. Dynegy and DHI had approximately $2 million and $(1) million accrued for the payment of interest and penalties at December 31, 2008 and December 31, 2007, respectively.

We expect that our unrecognized tax benefits could continue to change due to the settlement of audits and the expiration of statutes of limitation in the next twelve months; however, we do not anticipate any such change to have a significant impact on our results of operations, financial position or cash flows in the next twelve months.

Note 18—Dynegy's Earnings (Loss) Per Share

The reconciliation of basic earnings (loss) per share from continuing operations to diluted earnings (loss) per share from continuing operations of Dynegy common stock outstanding during the period is shown in the following table. Diluted earnings (loss) per share represents the amount of earnings (losses) for the period available to each share of Dynegy common stock outstanding during the period plus each share that would have been outstanding assuming the issuance of common shares for all dilutive potential common shares outstanding during the period.

	Year Ended December 31,		
	2008	2007	2006
	(in millions, except per share amounts)		
Income (loss) from continuing operations	$ 171	$ 116	$ (321)
Convertible preferred stock dividends	—	—	(9)
Income (loss) from continuing operations for basic earnings (loss) per share	171	116	(330)
Effect of dilutive securities:			
Interest on convertible subordinated debentures	—	—	3
Dividends on Series C convertible preferred stock	—	—	9
Income (loss) from continuing operations for diluted earnings (loss) per share	$ 171	$ 116	$ (318)
Basic weighted-average shares	840	752	459
Effect of dilutive securities:			
Stock options	2	2	2
Convertible subordinated debentures	—	—	20
Series C convertible preferred stock	—	—	28
Diluted weighted-average shares	842	754	509
Earnings (loss) per share from continuing operations:			
Basic	$0.20	$0.15	$(0.72)
Diluted (1)	$0.20	$0.15	$(0.72)

(1) When an entity has a net loss from continuing operations adjusted for preferred dividends, SFAS No. 128, "Earnings per Share", prohibits the inclusion of potential common shares in the computation of diluted per-share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the year ended December 31, 2006.

Note 19—Commitments and Contingencies

Legal Proceedings

Set forth below is a summary of our material ongoing legal proceedings. In accordance with SFAS No. 5, we record reserves for contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable. In addition, we disclose matters for which management believes a material loss is at least reasonably possible. In all instances, management has assessed the matters below based on current information and made a judgment concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of damages sought and the probability of success. Management's judgment may prove materially inaccurate and such judgment is made subject to the known uncertainty of litigation.

Gas Index Pricing Litigation. We, several of our affiliates, our former joint venture affiliate WCP (Generation) Holdings LLC ("West Coast Power") and other energy companies were named as defendants in numerous lawsuits in state and federal court claiming damages resulting from alleged price manipulation and false reporting of natural gas prices to various index publications in the 2000-2002 timeframe. Many of the cases have been resolved and those which remain are pending in Nevada federal district court and Tennessee state appellate court. Recent developments include:

- In February 2007, the Tennessee state court dismissed a class action on defendants' motion. Plaintiffs appealed and in November 2007, the case was argued to the appellate court. In October 2008, the appellate court reversed the dismissal and remanded the case for further proceedings. In December 2008, the defendants applied for leave to appeal the appellate court decision to the Tennessee Supreme Court.
- In February 2008, the United States District Court in Las Vegas, Nevada granted defendants' motion for summary judgment in a Colorado class action, which had been transferred to Nevada through the multi-district litigation management process, thereby dismissing the case and all of plaintiffs' claims. Plaintiffs moved for reconsideration and the court ordered additional briefing on plaintiffs' declaratory judgment claims. In January 2009, the court dismissed plaintiffs' remaining declaratory judgment claims. The decision is subject to appeal.
- The remaining six cases, three of which seek class certification, are also pending in Nevada federal court. Five of the cases were transferred through the multi-district litigation management process from other states, including Kansas, Wisconsin, Missouri and Illinois. All of the cases contain similar claims that individually and in conjunction with other energy companies, we engaged in an illegal scheme to inflate natural gas prices by providing false information to natural gas index publications. The complaints rely heavily on prior FERC and CFTC investigations into and reports concerning index manipulation in the energy industry. The lawsuits seek actual and punitive damages, restitution and/or expenses, and are currently in the discovery phase.

We continue to analyze the Gas Index Pricing Litigation and are vigorously defending the remaining individual matters. Due to the uncertainty of litigation, we cannot predict whether we will incur any liability in connection with these lawsuits. However, given the nature of the claims, an adverse result in these proceedings could have a material effect on our financial condition, results of operations and cash flows.

Nevada Power Arbitration. Through indirect subsidiaries, Chevron USA and we are equal stakeholders in Nevada Cogeneration Associates #2 ("Black Mountain"), a power generation facility located in Clark County, Nevada. Black Mountain operates under a long-term power sale agreement ("PSA") with NV Energy Inc (formerly known as Nevada Power Company) through April 2023. In October 2007, NV Energy Inc. ("NV Energy") initiated an arbitration against the joint venture seeking declaratory relief that (i) NV Energy's methodology for calculating a cumulative excess payment in the event of default or early termination is correct and (ii) the joint venture is obligated to repay to NV Energy the full amount of any outstanding excess payment in the event of a default or early termination or upon the expiration of the PSA in 2023. NV Energy alleged that as of December 31, 2007, the balance of the cumulative excess payment was approximately $136 million. NV Energy further alleged that the cumulative excess payment balance was projected to be approximately $365 million in 2023, which amount would be payable upon the scheduled termination of the PSA. We did not believe that any amount would be owed to NV Energy upon the scheduled termination of the PSA.

In July 2008, the parties presented evidence and arguments during an arbitration proceeding. In October 2008, following post hearing briefing and closing arguments, the case was submitted to the arbitrator for decision. In January 2009, the arbitrator issued an interim opinion, holding that under the PSA: (i) the cumulative excess payment was intended solely as a remedy in the event of a material breach of the PSA by Black Mountain, and that the cumulative excess payment amount, if one then exists, is not owed at the end of the contract term; and (ii) the cumulative excess payment must be calculated using simple interest, not compound interest. The arbitrator requested further briefing on reapportionment of costs associated with the arbitration. Once the arbitrator addresses the apportionment of costs, the interim order will become final.

New York Attorney General Subpoena. On September 17, 2007, Dynegy and four other companies received a subpoena from the Office of the New York Attorney General. The subpoena sought information and documents related to Dynegy's public disclosures concerning the expected impact of climate change and the regulation of greenhouse gas emissions. In October 2008, the Attorney General closed its inquiry and did not find any weakness or impropriety in Dynegy's past disclosures. Under an agreement reached with the Attorney General's Office, Dynegy acknowledged that it will continue to provide timely and relevant information to investors about climate change risk in accordance with applicable SEC disclosure requirements.

Cooling Water Intake Permits. The cooling water intake structures at several of our facilities are regulated under section 316(b) of the Clean Water Act. This provision generally requires that standards set for facilities require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available ("BTA") for minimizing adverse environmental impact. These standards are developed and implemented for power generating facilities through the National Pollutant Discharge Elimination System ("NPDES") permits or individual State Pollutant Discharge Elimination System ("SPDES") permits. Historically, standards for minimizing adverse environmental impacts of cooling water intakes have been made by permitting agencies on a case-by-case basis considering the best professional judgment of the permitting agency.

In 2004, the U.S. EPA issued Cooling Water Intake Structures Phase II regulations setting forth standards to implement the BTA requirements for cooling water intakes at existing facilities. The rule was challenged by several environmental groups and in 2007 was struck down by the U.S. Court of Appeals for the Second Circuit in *Riverkeeper, Inc. v. EPA*. The Court's decision remanded several provisions of the rule to the U.S. EPA for further rulemaking. Several parties sought review of the decision before the U.S. Supreme Court and in April 2008 that court granted review concerning whether the cost and benefit of controls could be considered by the agency in determining BTA. A decision by the U.S. Supreme Court is expected in early 2009.

The environmental groups that participate in NPDES and SPDES permit proceedings generally argue that only closed cycle cooling meets the BTA requirement. The issuance and renewal of NPDES or SPDES permits for three of our facilities have been challenged on this basis.

- Danskammer SPDES Permit—In January 2005, the New York State Department of Environmental Conservation ("NYSDEC") issued a Draft SPDES Permit renewal for the Danskammer plant. Three environmental groups sought to impose a permit requirement that the Danskammer plant install a closed cycle cooling system. A formal evidentiary hearing was held and the revised Danskammer SPDES Permit was issued on June 1, 2006 with conditions generally favorable to us. While the revised Danskammer SPDES Permit does not require installation of a closed cycle cooling system, it does require aquatic organism mortality reductions resulting from NYSDEC's determination of BTA requirements under its regulations. The petitioners appealed and on September 19, 2008, the Appellate Division issued its Memorandum and Judgment confirming the determination of NYSDEC in issuing the revised Danskammer SPDES Permit and dismissed the appeal. Both the Third Department and the New York Court of Appeals have denied petitions for leave to appeal.
- Roseton SPDES Permit—In April 2005, the NYSDEC issued a Draft SPDES Permit renewal for the Roseton plant. The Draft Roseton SPDES Permit would require the facility to actively manage its water intake to substantially reduce mortality of aquatic organisms. In July 2005, a public hearing was held to receive comments on the Draft Roseton SPDES Permit. Three environmental organizations filed petitions for party status in the permit renewal proceeding. The petitioners are seeking to impose a permit requirement that the Roseton plant install a closed cycle cooling system. In September 2006, the

administrative law judge issued a ruling admitting the petitioners to party status and setting forth the issues to be adjudicated in the permit renewal hearing. Various holdings in the ruling have been appealed to the Commissioner of NYSDEC by the petitioners, NYSDEC staff and us. We expect that the adjudicatory hearing on the Draft Roseton SPDES Permit will begin in 2009. We believe that the petitioners' claims lack merit and we plan to oppose those claims vigorously.

- Moss Landing NPDES Permit—The California Regional Water Quality Control Board ("Water Board") issued an NPDES permit for the Moss Landing Power Plant in 2000 in connection with modernization of the plant. A local environmental group sought review of the permit contending that the once through seawater-cooling system at Moss Landing should be replaced with a closed cycle cooling system to meet the BTA requirements. Following an initial remand from the courts, the Water Board affirmed its BTA finding. The Water Board's decision was affirmed by the Superior Court in 2004 and by the Court of Appeals in 2007. The petitioners filed a Petition for Review by the Supreme Court of California, which was granted in March 2008, with further action deferred pending disposition of petitions for certiorari in the U.S. Supreme Court regarding the Phase II Rule. We believe that petitioner's claims lack merit and we plan to oppose those claims vigorously.

Given the numerous variables and factors involved in calculating the potential costs associated with installing a closed cycle cooling system, any decision to install such a system at any of our plants would be made on a case-by-case basis considering all relevant factors at such time. If capital expenditures related to cooling water systems become great enough to render the operation of the plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate that facility and forego the capital expenditures.

Native Village of Kivalina and City of Kivalina v. ExxonMobil Corporation, et al. In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska initiated an action in federal court in the Northern District of California against DHI and 23 other companies in the energy industry. Plaintiffs claim that defendants' emissions of greenhouse gases including CO_2 contribute to climate change and have caused significant damage to a native Alaskan Eskimo village through increased vulnerability to waves, storm surges and erosion. In June 2008, defendants filed multiple motions to dismiss which are now fully briefed. A hearing on defendants' motions is scheduled for May 2009. We believe the plaintiffs' suit lacks merit and we intend to oppose their claims vigorously.

Ordinary Course Litigation. In addition to the matters discussed above, we are party to numerous legal proceedings arising in the ordinary course of business or related to discontinued business operations. In management's judgment, which may prove to be materially inaccurate as indicated above, the disposition of these matters will not materially affect our financial condition, results of operations or cash flows.

Other Commitments and Contingencies

In conducting our operations, we have routinely entered into long-term commodity purchase and sale commitments, as well as agreements that commit future cash flow to the lease or acquisition of assets used in our businesses. These commitments have been typically associated with commodity supply arrangements, capital projects, reservation charges associated with firm transmission, transportation, storage and leases for office space, equipment, plant sites, power generation assets and LPG vessel charters. The following describes the more significant commitments outstanding at December 31, 2008.

Purchase Obligations. We have firm capacity payments related to transportation of natural gas. Such arrangements are routinely used in the physical movement and storage of energy. The total of such obligations was $345 million as of December 31, 2008.

Transmission Obligation. We have a transmission obligation with respect to transmission services for our Griffith facility, which expires in 2039. Our obligation under this agreement is approximately $6 million per year through the term of the contract.

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

Consent Decree. In 2005, we settled a lawsuit filed by the U.S. EPA and the United States Department of Justice in the U.S. District Court for the Southern District of Illinois that alleged violations of the Clean Air Act and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating station. A Consent Decree was finalized in July 2005. Among other provisions of the Consent Decree, we are required to not operate certain of our power generating facilities after specified dates unless certain emission control equipment is installed. We have spent approximately $290 million through December 31, 2008 related to these Consent Decree projects and anticipate incurring significantly more costs over the course of the next five years in connection with the Consent Decree. 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.

Other Minimum Commitments. 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. The Vermilion facility is included in the GEN-MW segment. 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. Minimum commitments at December 31, 2008 were $2 million for each of the years ending 2009, 2010, 2011, 2012 and 2013 and a total of $2 million thereafter.

In the first quarter 2001, we acquired the DNE power generation facilities. These facilities consist of a combination of baseload, intermediate and peaking facilities aggregating approximately 1,700 MW. The facilities are approximately 50 miles north of New York City and were acquired for approximately $903 million cash, plus inventory and certain working capital adjustments. In May 2001, two of our subsidiaries completed a sale-leaseback transaction to provide term financing for the DNE facilities. Under the terms of the sale-leaseback transaction, our subsidiaries sold plants and equipment and agreed to lease them back for terms expiring within 34 years, exclusive of renewal options. We have no option to purchase the leased facilities at the end of their respective lease terms. If one or more of the leases were to be terminated because of an event of loss, because it becomes illegal for the applicable lessee to comply with the lease or because a change in law makes the facility economically or technologically obsolete, DHI would be required to make a termination payment. As of December 31, 2008, the termination payment would be approximately $930 million for all of the DNE facilities.

Minimum commitments in connection with office space, equipment, plant sites and other leased assets, including the leases discussed above, at December 31, 2008, were as follows: 2009—$149 million, 2010—$104 million, 2011—$119 million, 2012—$182 million, 2013—$146 million and beyond—$407 million.

Rental payments made under the terms of these arrangements totaled $148 million in 2008, $122 million in 2007 and $80 million in 2006.

We are party to two charter party agreements relating to VLGCs previously utilized in our former global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $14 million for each year from 2009 through 2012, and approximately $17 million for 2013 through lease expiration. The charter party rates payable under the two charter party agreements float in accordance with market based rates for similar shipping services. The $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 term of one charter is through September 2013 while the primary term of the second charter is through September 2014. 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. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements.

Guarantees and Indemnifications

In the ordinary course of business, we routinely enter into contractual agreements that contain various representations, warranties, indemnifications and guarantees. Examples of such agreements include, but are not limited to, service agreements, equipment purchase agreements, engineering and technical service agreements, asset sales and procurement and construction contracts. Some agreements contain indemnities that cover the other party's negligence or limit the other party's liability with respect to third party claims, in which event we will effectively be indemnifying the other party. Virtually all such agreements contain representations or warranties that are covered by indemnifications against the losses incurred by the other parties in the event such representations and warranties are false. While there is always the possibility of a loss related to such representations, warranties, indemnifications and guarantees in our contractual agreements, and such loss could be significant, in most cases management considers the probability of loss to be remote. Related to the indemnifications discussed below, we have accrued approximately $6 million as of December 31, 2008.

West Coast Power Indemnities. In connection with the sale of our 50 percent interest in West Coast Power to NRG on March 31, 2006, an agreement was executed to allocate responsibility for managing certain litigation and provide for certain indemnities with respect to such litigation. The agreement provides that we will manage the Gas Index Pricing Litigation described above for which NRG could suffer a loss subsequent to the closing and that we would indemnify NRG for all costs or losses resulting from such litigation, as well as from other proceedings based on similar acts or omissions. West Coast Power is no longer a party to any active Gas Index Pricing Litigation matters. The indemnification agreement further provides that NRG assumes responsibility for all defense costs and any risk of loss, subject to certain conditions and limitations, arising from a February 2002 complaint filed at FERC by the California Public Utilities Commission alleging that several parties, including West Cost Power subsidiaries, overcharged the State of California for wholesale power. FERC found the rates charged by wholesale suppliers to be just and reasonable. However, this matter was appealed to the U.S. Supreme Court, which remanded the case to FERC for further review.

Targa Indemnities. During 2005, as part of our sale of DMSLP, we agreed to indemnify Targa Resources, Inc. ("Targa") against losses it may incur under indemnifications DMSLP provided to purchasers of certain assets, properties and businesses disposed of by DMSLP prior to our sale of DMSLP. We have incurred no significant expense under these prior indemnities and deem their value to be insignificant. We have recorded an accrual in association with the remediation of groundwater contamination at the Breckenridge Gas Processing Plant. The indemnification provided by DMSLP to the purchaser of the plant has a limit of $5 million. We have also indemnified Targa for certain tax matters arising from periods prior to our sale of DMSLP. We have recorded a tax reserve associated with this indemnification.

Illinois Power Indemnities. As a condition of Dynegy's 2004 sale of Illinois Power and its interest in Electric Energy Inc.'s plant in Joppa, Illinois, Dynegy provided indemnifications to third parties regarding environmental, tax, employee and other representations. These indemnifications are limited to a maximum recourse of $400 million. Additionally, Dynegy has indemnified third parties against losses resulting from possible adverse regulatory actions taken by the ICC that could prevent Illinois Power from recovering costs incurred in connection with purchased natural gas and investments in specified items. Although there is no limitation on Dynegy's liability under this indemnity, the amount of the indemnity is limited to 50 percent of any such losses. Dynegy has made certain payments in respect of these indemnities following regulatory action by the ICC, and has established reserves for further potential indemnity claims. Further events, which fall within the scope of the indemnity, may still occur. However, Dynegy is not required to accrue a liability in connection with these indemnifications, as management cannot reasonably estimate a range of outcomes or at this time considers the probability of an adverse outcome as only reasonably possible. Dynegy intends to contest any proposed regulatory actions.

Other Indemnities. During 2003, as part of our sales of the Rough and Hornsea natural gas storage facilities and certain natural gas liquids assets, we provided indemnities to third parties regarding tax representations. Maximum recourse under these indemnities is limited to $857 million and $28 million, respectively. As of December 31, 2008, no claims have been made against these indemnities. We also entered into similar indemnifications regarding environmental, tax, employee and other representations when completing other asset sales such as, but not limited to the Rolling Hills, Calcasieu and CoGen Lyondell power generating facilities. As of December 31, 2008, no claims have been made against these indemnities.

Note 20—Capital Stock

At December 31, 2008, Dynegy had authorized capital stock consisting of 2,100,000,000 shares of Class A common stock, $0.01 par value per share and 850,000,000 shares of Class B common stock, $0.01 par value per share.

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.

Preferred Stock. Dynegy has authorized preferred stock consisting of 100,000,000 shares, $0.01 par value. Dynegy preferred stock may be issued from time to time in one or more series, the shares of each series to have such designations and powers, preferences, rights, qualifications, limitations and restrictions thereof as specified by Dynegy's Board of Directors.

Common Stock. At December 31, 2008, there were 845,821,277 shares of Dynegy Class A and B common stock issued in the aggregate and 2,568,286 shares were held in treasury. During 2008 and 2007, no quarterly cash dividends were paid by Dynegy.

Pursuant to the terms of the Merger Agreement, Dynegy established two classes of common shares, Class A and Class B. All of Dynegy's outstanding Class B common stock is owned by the LS Contributing Entities and its permitted transferees, affiliates and associates (the "LS Control Group"). Generally, holders of Class B common stock vote together with the holders of Class A common stock as a single class on every matter acted upon by the stockholders except for the following matters:

- the holders of Class B common stock vote as a separate class for the election of up to three of Dynegy's directors, while the holders of Class A common stock vote as a separate class for the remaining directors;
- any amendment to the provisions of Dynegy's Amended and Restated Certificate of Incorporation addressing the voting rights of holders of Class A and Class B common stock or to Section 7 of Article III or Article X of its Bylaws requires the affirmative vote of a majority of the outstanding shares of Class B common stock voting as a separate class, and the affirmative vote of a majority of the shares of common stock, voting together as a single class, except that no such stockholder approval is required

with respect to an amendment to Section 7 of Article III or Article X of Dynegy's Amended and Restated Bylaws if such amendment is approved by a majority of the Class B Directors present at a meeting where such amendment is considered and by a majority of all Dynegy directors; and

- any agreement of merger or consolidation if a party to such agreement is a member of the LS Control Group or an affiliate of such group requires the affirmative vote of a majority of the shares of Class A common stock outstanding, voting as a separate class, and the affirmative vote of a majority of all shares of common stock outstanding, voting together as a single class.

Holders of Dynegy's Class A and Class B common stock are entitled to one vote per share on all matters submitted to a vote of stockholders. Holders of common stock will not be entitled to cumulative voting. The voting rights of any holders of common stock will be subject to the voting rights of holders of any series of preferred stock that may be issued from time to time.

Subject to the preferences of preferred stock, holders of Dynegy's Class A and Class B common stock have equal and ratable rights to dividends, when and if dividends are declared by Dynegy's Board of Directors. Holders of Dynegy's Class A and Class B common stock are entitled to share ratably, as a single class, in all of Dynegy's assets available for distribution to holders of shares of common stock upon the liquidation, dissolution or winding up of Dynegy's affairs, after payment of Dynegy's liabilities and any amounts to holders of preferred stock, if any.

A share of Class B common stock automatically converts into a share of Class A common stock if it is transferred to any person other than a member of the LS Control Group. Additionally, each share of Class B common stock automatically converts into a share of Class A common stock when the outstanding shares of Class B common stock represent less than 10 percent of the total outstanding shares of Dynegy's common stock. As long as the outstanding shares of Class B common stock represent at least 10 percent of the total outstanding shares, each share of Class A common stock owned by the LS Control Group will automatically be converted into one share of Class B common stock.

Holders of Class A and Class B common stock generally are not entitled to preemptive rights, subscription rights, or redemption rights, except that the LS Control Group is entitled to preemptive rights under the shareholder agreement. The rights and preferences of holders of common stock are subject to the rights of any series of preferred stock we may issue.

Common stock activity for the three years ended December 31, 2008 was as follows:

	Class A Common Stock		Class B Common Stock held by CUSA		Class B Common Stock held by LS Power	
	Shares	Amount	Shares	Amount	Shares	Amount
			(in millions)			
December 31, 2005	305	$ 2,949	97	$ 1,006	—	$—
Options exercised	3	5	—	—	—	—
401(k) plan and profit sharing	1	3	—	—	—	—
Equity issuance	40	185	—	—	—	—
Equity conversion	54	225	—	—	—	—
December 31, 2006	403	$ 3,367	97	$ 1,006	—	$—
Options exercised	2	1	—	—	—	—
401(k) plan and profit sharing	1	1	—	—	—	—
LS Power Business Combination:						
Conversion of Chevron Class B shares to Class A shares	97	1,006	(97)	(1,006)	—	—
Conversion from Illinois entity to Delaware entity	—	(4,370)	—	—	—	—
Issuance of LS Power Class B shares	—	—	—	—	340	3
December 31, 2007	503	$ 5	—	$ —	340	$ 3
Options exercised	2	—	—	—	—	—
401(k) plan and profit sharing	1	—	—	—	—	—
December 31, 2008	506	$ 5	—	$ —	340	$ 3

Treasury Stock. During 2008, 2007 and 2006, Class A common shares purchased into treasury totaled 119,027, 662,255 and 72,978, respectively. All of the purchases were related to shares withheld to satisfy income tax withholding requirements in connection with forfeitures of restricted stock awards

Stock Award Plans. Dynegy has nine stock option plans, all of which provide for the issuance of authorized shares of Dynegy's Class A common stock. Restricted stock awards and option grants are issued under the plans. Each option granted is exercisable at a strike price, which ranges from $1.77 per share to $56.98 per share for options currently outstanding. A brief description of each plan is provided below:

- ***NGC Plan.*** Created early in Dynegy's history and revised prior to Dynegy becoming a publicly traded company in 1996, this plan provided for the issuance of 13,651,802 authorized shares, had a 10-year term, and expired in May 2006. All option grants are vested.
- ***Employee Equity Plan.*** This plan is the only plan under which Dynegy granted options below the fair market value of its Class A common stock on the date of grant. This plan provided for the issuance of 20,358,802 authorized shares and expired in May 2002. Grants under this plan vested on the fifth anniversary from the date of the grant. All option grants are vested.
- ***Illinova Plan.*** Adopted by Illinova prior to the merger with Dynegy, this plan provided for the issuance of 3,000,000 authorized shares and expired upon the merger date in February 2000. All option grants are vested.
- ***Extant Plan.*** Adopted by Extant prior to its acquisition by Dynegy, this plan provided for the issuance of 202,577 authorized shares and expired in September 2000. Grants from this plan vested at 25 percent per year. All option grants are vested.

- ***UK Plan.*** This plan provided for the issuance of 276,000 authorized shares and has been terminated. All option grants are vested.
- ***Dynegy 1999 Long-Term Incentive Plan ("LTIP").*** This annual compensation plan provides for the issuance of 6,900,000 authorized shares, has a 10-year term and expires in 2009. All option grants are vested.
- ***Dynegy 2000 LTIP.*** This annual compensation plan, created for all employees upon Illinova's merger with us, provides for the issuance of 10,000,000 authorized shares, has a 10-year term and expires in June 2009. Grants from this plan vest in equal annual installments over a three-year period.
- ***Dynegy 2001 Non-Executive LTIP.*** This plan is a broad-based plan and provides for the issuance of 10,000,000 authorized shares, has a ten-year term and expires in September 2011. Grants from this plan vest in equal annual installments over a three-year period.
- ***Dynegy 2002 LTIP.*** This annual compensation plan provides for the issuance of 10,000,000 authorized shares, has a 10-year term and expires in May 2012. Grants from this plan vest in equal annual installments over a three-year period.

All options granted under Dynegy's option plans cease vesting for employees who are terminated for cause. For severance eligible terminations, as defined under the applicable severance pay plan, disability, retirement or death, continued vesting and/or an extended period in which to exercise vested options may apply, dependent upon the terms of the grant agreement applying to a specific grant that was awarded. It has been Dynegy's practice to issue shares of common stock upon exercise of stock options generally from previously unissued shares. Options awarded to Dynegy's executive officers and others who participate in our Executive Change in Control Severance Pay Plan vest immediately upon the occurrence of a change in control.

The Merger constituted a change in control as defined in Dynegy's severance pay plans, as well as the various grant agreements. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for further discussion of the transaction. As a result, all options previously granted to employees fully vested immediately upon the closing of the Merger and related change in control. This occurrence resulted in the accelerated vesting of the unvested tranche of previous option grants issued in 2006 and 2005, which did not have a material effect on Dynegy's financial condition, results of operations or cash flows.

During 2006, Dynegy entered into an exchange transaction with its Chairman and CEO. Under the terms of the transaction, the purpose of which was to address uncertainties created by proposed regulations issued in late 2005 pursuant to Section 409A of the Internal Revenue Code, Dynegy cancelled all of the 2,378,605 stock options then held by its Chairman and CEO. As consideration for canceling these stock options, Dynegy granted its Chairman and CEO 967,707 stock options at an exercise price of $4.88, which equaled the closing price of its Class A common stock on the date of grant, and made a cash payment to him of approximately $5.6 million on January 15, 2007 based on the in-the-money value of the vested stock options that were cancelled. These stock options vested immediately upon the closing of the Merger and related change in control. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for further discussion. We were not required to record any incremental compensation expense in connection with the transaction.

Compensation expense related to options granted and restricted stock awarded totaled $15 million, $19 million and $8 million for the years ended December 31, 2008, 2007 and 2006, respectively. We recognize compensation expense ratably over the vesting period of the respective awards. Tax benefits for compensation expense related to options granted and restricted stock awarded totaled $5 million, $8 million and $3 million for the years ended December 31, 2008, 2007 and 2006, respectively. As of December 31, 2008, $5 million of total unrecognized compensation expense related to options granted and restricted stock awarded is expected to be recognized over a weighted-average period of 1.7 years. The total fair value of shares vested was $7 million, $20 million and $4 million for the years ended December 31, 2008, 2007 and 2006, respectively. We did not capitalize or use cash to settle any share-based compensation in the years ended December 31, 2008, 2007 or 2006, other than as described above.

Cash received from option exercises for the years ended December 31, 2008, 2007 and 2006 was $2 million, $4 million and $5 million, and the tax benefit realized for the additional tax deduction from share-based payment awards totaled $3 million, $4 million and $3 million, respectively. The total intrinsic value of options exercised and released for the years ended December 31, 2008, 2007 and 2006 was $5 million, $23 million and $5 million, respectively.

In 2008, we granted stock-based compensation awards to certain of our employees that cliff vest after three years based on achievement of Dynegy's stock price target on March 6, 2011. In 2007, we granted stock-based compensation awards to certain of our employees that cliff vest after three years based on achievement of Dynegy's stock price target on April 23, 2010. Compensation expense recorded in the years ended December 31, 2008 and 2007 related to these "performance units" was $5 million and $4 million, respectively, and was accrued in Other long-term liabilities in our consolidated balance sheets. The Merger constituted a change in control as related to the 2006 performance units. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for further discussion.

Stock option activity for the years ended December 31, 2008, 2007 and 2006 was as follows:

	Year Ended December 31,					
	2008		2007		2006	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(options in thousands)					
Outstanding at beginning of period	8,420	$12.60	7,361	$12.63	9,314	$12.66
Granted	1,565	$ 7.48	2,136	$ 9.67	3,268	$ 4.88
Exercised	(555)	$ 4.03	(872)	$ 4.29	(1,560)	$ 3.46
Cancelled or expired	(614)	$16.88	(205)	$18.60	(3,661)	$ 9.68
Outstanding at end of period	8,816	$11.93	8,420	$12.60	7,361	$12.63
Vested and unvested expected to vest	8,702	$11.98	8,137	$12.70	6,898	$13.16
Exercisable at end of period	5,878	$13.64	6,305	$13.59	3,774	$20.07

	Year Ended December 31, 2008	
	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at end of period	6.22	$0.04
Vested and unvested expected to vest	6.18	$0.04
Exercisable at end of period	5.03	$0.04

During the three-year period ended December 31, 2008, we did not grant any options at an exercise price less than the market price on the date of grant.

Options outstanding as of December 31, 2008 are summarized below:

Range of Exercise Prices	Options Outstanding: Number of Options Outstanding at December 31, 2008	Options Outstanding: Weighted Average Remaining Contractual Life (Years)	Options Outstanding: Weighted Average Exercise Price	Options Exercisable: Number of Options Exercisable at December 31, 2008	Options Exercisable: Weighted Average Exercise Price
	(options in thousands)				
$1.77-$4.48	658	4.75	$ 3.68	658	$ 3.68
$4.88	2,402	7.21	$ 4.88	2,402	$ 4.88
$7.02	12	0.38	$ 7.02	12	$ 7.02
$7.48	1,552	9.18	$ 7.48	—	$ —
$8.70	9	8.70	$ 8.70	3	$ 8.70
$9.67	2,070	7.87	$ 9.67	695	$ 9.67
$10.17-$23.85	1,476	1.68	$20.64	1,471	$20.68
$28.47-$50.63	620	1.96	$44.90	620	$44.90
$52.50	5	1.70	$52.50	5	$52.50
$56.98	12	0.38	$56.98	12	$56.98
	8,816			5,878	

For stock options, we determine the fair value of each stock option at the grant date using a Black-Scholes model, with the following weighted-average assumptions used for grants.

	Year Ended December 31, 2008	2007	2006
Dividends	—	—	—
Expected volatility (historical)	45.07%	45.60%	48.8%
Risk-free interest rate	3.80%	4.9%	5.1%
Expected option life	6 Years	6 Years	6 Years

The expected volatility was calculated based on a five-, four- and three-year historical volatility of Dynegy's Class A common stock price for the years ended December 31, 2008, 2007 and 2006, respectively. The risk-free interest rate was calculated based upon observed interest rates appropriate for the term of our employee stock options. Currently, we calculate the expected option life using the simplified methodology suggested by SAB 107, "Share-Based Payment". For restricted stock awards, we consider the fair value to be the closing price of the stock on the grant date. We recognize the fair value of our share-based payments over the vesting periods of the awards, which is typically a three-year service period.

The weighted average grant-date fair value of options granted during the years ended December 31, 2008, 2007 and 2006 was $3.63, $4.91 and $2.61, respectively.

Restricted stock activity for the three years ended December 31, 2008 was as follows:

	Year Ended December 31,			
	2008	2008 Weighted Average Grant Date Fair Value	2007	2006
	(restricted stock shares in thousands)			
Outstanding at beginning of period	1,552	$9.67	2,114	1,239
Granted	1,445 (1)	$7.48	1,643 (2)	1,311 (3)
Vested	(367)	$9.53	(2,113)	(251)
Cancelled or expired	(85)	$8.69	(92)	(185)
Outstanding at end of period	2,545	$8.48	1,552	2,114

(1) We awarded 1,445,061 shares of restricted stock in March 2008. The closing stock price was $7.48 on the date of the award.
(2) We awarded 1,639,088 shares, 1,967 shares and 2,299 shares of restricted stock in April 2007, May 2007 and September 2007, respectively. The closing stock prices were $9.67, $10.17 and $8.70, respectively, on the dates of the awards.
(3) We awarded 1,311,149 shares of restricted stock in March 2006. The closing stock price was $4.88 on the date of the award.

All restricted stock awards to employees vest immediately upon the occurrence of a change in control in accordance with the terms of the applicable Change in Control Severance Pay Plan. The Merger constituted a change in control as defined in our restricted stock agreements. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for further discussion.

Note 21—Employee Compensation, Savings and Pension Plans

We sponsor and administer defined benefit plans and defined contribution plans for the benefit of our employees. We also provide other post retirement benefits to retirees who meet age and service requirements. The following summarizes these plans:

Short-Term Incentive Plan. We maintain a discretionary incentive compensation plan to provide employees with rewards for the achievement of corporate goals and individual, professional accomplishments. Specific awards are determined by the Compensation and Human Resources Committee of the Board of Directors and are based on predetermined goals and objectives established at the start of each performance year.

401(k) Savings Plans. During the year ended December 31, 2008, our employees participated in four 401(k) savings plans, all of which meet the requirements of Section 401(k) of the Internal Revenue Code and are defined contribution plans subject to the provisions of ERISA. The following summarizes the plans:

- ***Dynegy Inc. 401(k) Savings Plan.*** This plan and the related trust fund are established and maintained for the exclusive benefit of participating employees in the United States. Generally, all employees of designated Dynegy subsidiaries are eligible to participate in the plan. Employee pre-tax and Roth contributions to the plan are matched by the company at 100 percent, up to a maximum of five percent of base pay, subject to IRS limitations. Vesting in company contributions is based on years of service at 25 percent per full year of service. However, effective January 1, 2009, generally, vesting in company contributions is based on years of service at 50 percent per full year of service. The Plan also allows for a discretionary contribution to eligible employee accounts for each plan year, subject to the sole discretion of the Compensation and Human Resources Committee of the Board of Directors. Matching and discretionary contributions, if any, are allocated in the form of units in the Dynegy common stock fund. During the years ended December 31, 2008, 2007 and 2006, we issued approximately 0.8 million, 0.3 million and 0.3 million shares, respectively, of Dynegy's Class A common stock in the form of matching contributions to fund the plan. No discretionary contributions were made for any of the years in the three-year period ended December 31, 2008.

- ***Dynegy Midwest Generation, Inc. 401(K) Savings Plan (formerly the Illinois Power Company Incentive Savings Plan)*** and ***Dynegy Midwest Generation, Inc. 401(K) Savings Plan for Employees Covered Under a Collective Bargaining Agreement (formerly the Illinois Power Company Incentive Savings Plan for Employees Covered Under A Collective Bargaining Agreement).*** We match 50 percent of employee pre-tax and Roth contributions to the plans, up to a maximum of 6 percent of compensation, subject to IRS limitations. Employees are immediately 100 percent vested in all contributions. The Plan also provides for an annual discretionary contribution to eligible employee accounts for a plan year, subject to the sole discretion of the Compensation and Human Resources Committee of the Board of Directors. Matching contributions and discretionary contributions, if any, to the plans are initially allocated in the form of units in the Dynegy common stock fund. During the years ended December 31, 2008, 2007 and 2006, we issued 0.3 million, 0.1 million and 0.2 million shares, respectively, of Dynegy's Class A common stock in the form of matching contributions to the plans. No discretionary contributions were made for any of the years in the three-year period ended December 31, 2008.

- ***Dynegy Northeast Generation, Inc. Savings Incentive Plan.*** Under this plan we match 50 percent of employee pre-tax contributions up to six percent of base salary for union employees and 50 percent of employee contributions up to eight percent of base salary for non-union employees, in each case subject to IRS limitations. Employees are immediately 100 percent vested in our contributions. Matching contributions to this plan are made in cash and invested according to the employee's investment discretion.

During the years ended December 31, 2008, 2007 and 2006, we recognized aggregate costs related to these employee compensation plans of $5 million, $4 million and $3 million, respectively.

Pension and Other Post-Retirement Benefits

We have various defined benefit pension plans and post-retirement benefit plans. Generally, all employees participate in the pension plans (subject to the plans eligibility requirements), but only some of our employees participate in the other post-retirement medical and life insurance benefit plans. Our pension plans are in the form of cash balance plans and more traditional career average or final average pay formula plans.

Restoration Plans. In 2008, we also adopted the Dynegy Inc. Restoration 401(k) Savings Plan, or the Restoration 401(k) Plan, and the Dynegy Inc. Restoration Pension Plan, or the Restoration Pension Plan, two nonqualified plans that supplement or restore benefits lost by certain of our highly compensated employees under the qualified plans as a result of Internal Revenue Code limitations that apply to the qualified plans. The Restoration 401(k) Plan is intended to supplement benefits under certain of the 401(k) plans, and the Restoration Pension Plan is intended to supplement benefits under certain of the pension plans. Employees who are eligible employees under the related qualified plans and earn in excess of certain of the qualified plan limits are eligible to participate in the restoration plans. The definitions of plan pay under the restoration plans, as well as the vesting rules, mirror those under the related qualified plans. Benefits under the restoration plans are paid as a lump sum.

Obligations and Funded Status. The following tables contain information about the obligations and funded status of these plans on a combined basis:

	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
	(in millions)			
Projected benefit obligation, beginning of the year	$182	$182	$ 58	$ 61
Service cost	11	10	3	3
Interest cost	11	10	4	4
Actuarial (gain) loss	17	(15)	(2)	(9)
Benefits paid	(4)	(5)	(1)	(1)
Plan amendments	—	—	(1)	—
Projected benefit obligation, end of the year	$217	$182	$ 61	$ 58
Fair value of plan assets, beginning of the year	$154	$135	$—	$—
Actual return on plan assets	(44)	10	—	—
Employer contributions	29	14	1	1
Benefits paid	(4)	(5)	(1)	(1)
Fair value of plan assets, end of the year	$135	$154	$—	$—
Funded status	$ (82)	$ (28)	$ (61)	$ (58)

The accumulated benefit obligation for all defined benefit pension plans was $187 million and $125 million at December 31, 2008 and 2007, respectively. The following summarizes information for our defined benefit pension plans, all of which have an accumulated benefit obligation in excess of plan assets at December 31, 2008:

	December 31,	
	2008	2007
	(in millions)	
Projected benefit obligation	$217	$143
Accumulated benefit obligation	187	125
Fair value of plan assets	135	120

On September 29, 2006, the FASB issued SFAS No. 158. SFAS No. 158 requires employers to recognize the overfunded or underfunded status of a defined benefit or other postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position, and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income (loss).

Under SFAS No. 158, adjustments to the minimum pension liability were eliminated. In the year of adoption, we were required to adjust the minimum pension liability for a final time in accordance with SFAS No. 87. The following table summarizes the change to accumulated other comprehensive income (loss) associated with the minimum pension liability:

	2008	2007	2006
		(in millions)	
Change in minimum liability included in other comprehensive income (loss) (net of tax benefit (expense) of zero, zero million and ($5) million, respectively)	$—	$—	$10

Subsequent to the final minimum pension liability adjustment, we were required to recognize as a component of Accumulated other comprehensive income (loss) the gains or losses and prior service costs that existed at December 31, 2006, but that had not been recognized as components of net period benefit cost pursuant to SFAS No. 87 and SFAS No. 106. As a result, the pre-tax amounts recognized in accumulated other comprehensive income (loss) consist of:

	Year Ended December 31,			
	2008		2007	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
	(in millions)			
Prior service cost	$ 5	$ (1)	$ 6	$—
Actuarial loss	95	11	22	13
Net amount recognized	$100	$10	$28	$ 13

Amounts recognized in the consolidated balance sheets consist of:

	Year Ended December 31,			
	2008		2007	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
	(in millions)			
Current liabilities	$—	$ (1)	$—	$ (1)
Noncurrent liabilities	(82)	(60)	(28)	(57)
Net amount recognized	$ (82)	$(61)	$ (28)	$(58)

The estimated net actuarial loss and prior service cost that will be amortized from Accumulated other comprehensive income (loss) into net periodic benefit cost during the year ended December 31, 2009 for the defined benefit pension plans are less than $4 million and $1 million, respectively. The estimated net actuarial loss and prior service cost that will be amortized from Accumulated other comprehensive income (loss) into net periodic benefit cost during the year ended December 31, 2009 for other postretirement benefit plans are both zero. The amortization of prior service cost is determined using a straight line amortization of the cost over the average remaining service period of employees expected to receive benefits under the Plan.

Components of Net Periodic Benefit Cost. The components of net periodic benefit cost were:

	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
	(in millions)					
Service cost benefits earned during period	$ 11	$ 10	$ 9	$ 3	$ 3	$ 3
Interest cost on projected benefit obligation	11	10	10	3	4	3
Expected return on plan assets	(13)	(11)	(10)	—	—	—
Amortization of prior service costs	1	1	1	—	—	—
Recognized net actuarial loss	—	1	3	1	1	1
Net periodic benefit cost	$ 10	$ 11	$ 13	$ 7	$ 8	$ 7
Additional cost due to curtailment	—	—	3	—	—	—
Total net periodic benefit cost	$ 10	$ 11	$ 16	$ 7	$ 8	$ 7

Assumptions. The following weighted average assumptions were used to determine benefit obligations:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2008	2007	2008	2007
Discount rate (1)	6.12%	6.46%	5.93%	6.48%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

(1) We utilized a yield curve approach to determine the discount. Projected benefit payments for the plans were matched against the discount rates in the yield curve.

The following weighted average assumptions were used to determine net periodic benefit cost:

	Pension Benefits			Other Benefits		
	Year Ended December 31,			Year Ended December 31,		
	2008	2007	2006	2008	2007	2006
Discount rate	6.46%	5.87%	5.52%	6.48%	5.90%	5.53%
Expected return on plan assets	8.25%	8.25%	8.25%	N/A	N/A	N/A
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

Our expected long-term rate of return on plan assets for the year ended December 31, 2009 will be 8.25% percent. This figure begins with a blend of asset class-level returns developed under a theoretical global capital asset pricing model methodology conducted by an outside consultant. In development of this figure, the historical relationships between equities and fixed income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long-term. Current market factors such as inflation and interest rates are also incorporated in the assumptions. The figure also incorporates an upward adjustment reflecting the plan's use of active management and favorable past experience.

The following summarizes our assumed health care cost trend rates:

	December 31,	
	2008	2007
Health care cost trend rate assumed for next year	7.83%	8.99%
Ultimate trend rate	4.90%	5.00%
Year that the rate reaches the ultimate trend rate	2060	2016

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The impact of a one percent increase/decrease in assumed health care cost trend rates is as follows:

	Increase	Decrease
	(in millions)	
Aggregate impact on service cost and interest cost	$ 1	$(1)
Impact on accumulated post-retirement benefit obligation	$11	$(9)

Plan Assets. We employ a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. The intent of this strategy is to minimize plan expenses by outperforming plan liabilities over the long run. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition.

The investment portfolio contains a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks as well as growth, value, and small and large capitalizations.

Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying investment. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, periodic asset/liability studies, and annual liability measurements.

Our pension plans' weighted-average asset allocations by asset category were as follows:

	December 31,	
	2008	2007
Equity securities	65%	64%
Debt securities	35%	36%
Total	100%	100%

Equity securities did not include any of Dynegy's Class A common stock at December 31, 2008 or 2007.

Contributions and Payments. During the year ended December 31, 2008, we contributed approximately $29 million to our pension plans and $1 million to our other post-retirement benefit plans. In 2009, we expect to contribute approximately $27 million to our pension plans and $1 million to our other postretirement benefit plans.

Our expected benefit payments for future services for our pension and other postretirement benefits are as follows:

	Pension Benefits	Other Benefits
	(in millions)	
2009	$10	$ 1
2010	10	2
2011	10	2
2012	10	2
2013	11	3
2014 – 2018	78	19

Note 22—Segment Information

We report results of our power generation business in the following segments: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Beginning in the first quarter 2008, 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 and depreciation and amortization. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements.

During 2008, one customer in our GEN-MW segment and one customer in our GEN-NE segment accounted for approximately 25 percent and 11 percent of our consolidated revenues, respectively. During 2007, two customers in our GEN-MW segment and one customer in our GEN-NE segment accounted for approximately 23 percent, 11 percent and 17 percent of our consolidated revenues, respectively. During 2006, two customers in our GEN-MW segment and one customer in our GEN-NE segment accounted for approximately 23 percent, 19 percent and 18 percent of our consolidated revenues, respectively.

In the second quarter 2007, we discontinued the use of hedge accounting for certain derivative transactions affecting the GEN-MW, GEN-WE and GEN-NE segments. The operating results presented herein reflect the changes in market values of derivative instruments entered into by each of these segments. Please read Note 6—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

Reportable segment information for Dynegy, including intercompany transactions accounted for at prevailing market rates, for the years ended December 31, 2008, 2007 and 2006 is presented below:

Dynegy's Segment Data as of and for the Year Ended December 31, 2008
(in millions)

	Power Generation				
	GEN-MW	**GEN-WE**	**GEN-NE**	**Other**	**Total**
Unaffiliated revenues:					
Domestic	$1,623	$ 925	$ 890	$ (5)	$ 3,433
Other	—	—	116	—	116
Total revenues	$1,623	$ 925	$1,006	$ (5)	$ 3,549
Depreciation and amortization	$ (206)	$ (101)	$ (54)	$ (10)	$ (371)
Impairment and other charges	—	(47)	—	—	(47)
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 taxes					246
Income tax expense					(75)
Income from continuing operations					171
Income from discontinued operations, net of taxes					3
Net income					$ 174
Identifiable assets:					
Domestic	$6,763	$3,410	$2,534	$1,494	$14,201
Other	—	—	5	7	12
Total	$6,763	$3,410	$2,539	$1,501	$14,213
Unconsolidated investments	$ —	$ —	$ —	$ 15	$ 15
Capital expenditures and investments in unconsolidated affiliates	$ (530)	$ (29)	$ (36)	$ (32)	$ (627)

Dynegy's Segment Data as of and for the Year Ended December 31, 2007
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$1,325	$ 689	$ 920	$ 12	$ 2,946
Other	—	—	156	1	157
Total revenues	$1,325	$ 689	$1,076	$ 13	$ 3,103
Depreciation and amortization	$ (194)	$ (73)	$ (45)	$ (13)	$ (325)
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 taxes					267
Income tax expense					(151)
Income from continuing operations					116
Income from discontinued operations, net of taxes					148
Net income					$ 264
Identifiable assets:					
Domestic	$6,507	$3,251	$2,352	$1,075	$13,185
Other	—	5	12	19	36
Total	$6,507	$3,256	$2,364	$1,094	$13,221
Unconsolidated investments	$ —	$ 18	$ —	$ 61	$ 79
Capital expenditures and investments in unconsolidated affiliate	$ (300)	$ (17)	$ (47)	$ (25)	$ (389)

Dynegy's Segment Data as of and for the Year Ended December 31, 2006
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$ 969	$ 87	$ 501	$ 66	$1,623
Other	—	—	129	18	147
	969	87	630	84	1,770
Intersegment revenues	—	—	(21)	21	—
Total revenues	$ 969	$ 87	$ 609	$ 105	$1,770
Depreciation and amortization	$ (168)	$ (8)	$ (24)	$ (17)	$ (217)
Impairment and other charges	(110)	(9)	—	—	(119)
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 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)
Identifiable assets:					
Domestic	$5,036	$440	$1,373	$ 490	$7,339
Other	—	5	13	180	198
Total	$5,036	$445	$1,386	$ 670	$7,537
Capital expenditures	$ (101)	$ (24)	$ (22)	$ (8)	$ (155)

Reportable segment information for DHI, including intercompany transactions accounted for at prevailing market rates, for the years ended December 31, 2008, 2007 and 2006 is presented below:

DHI's Segment Data as of and for the Year Ended December 31, 2008
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$1,623	$ 925	$ 890	$ (5)	$ 3,433
Other	—	—	116	—	116
Total revenues	$1,623	$ 925	$1,006	$ (5)	$ 3,549
Depreciation and amortization	$ (206)	$ (101)	$ (54)	$ (10)	$ (371)
Impairment and other charges	—	(47)	—	—	(47)
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 taxes					328
Income tax expense					(123)
Income from continuing operations					205
Income from discontinued operations, net of taxes					3
Net income					$ 208
Identifiable assets:					
Domestic	$6,763	$3,410	$2,534	$1,455	$14,162
Other	—	—	5	7	12
Total	$6,763	$3,410	$2,539	$1,462	$14,174
Capital expenditures	$ (530)	$ (29)	$ (36)	$ (16)	$ (611)

DHI's Segment Data as of and for the Year Ended December 31, 2007
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$1,325	$ 689	$ 920	$ 12	$ 2,946
Other	—	—	156	1	157
Total revenues	$1,325	$ 689	$1,076	$ 13	$ 3,103
Depreciation and amortization	$ (194)	$ (73)	$ (45)	$ (13)	$ (325)
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 taxes					292
Income tax expense					(116)
Income from continuing operations					176
Income from discontinued operations, net of taxes					148
Net income					$ 324
Identifiable assets:					
Domestic	$6,507	$3,256	$2,352	$ 973	$13,088
Other	—	—	12	7	19
Total	$6,507	$3,256	$2,364	$ 980	$13,107
Unconsolidated investments	$ —	$ 18	$ —	$ —	$ 18
Capital expenditures	$ (300)	$ (17)	$ (47)	$ (15)	$ (379)

DHI's Segment Data as of and for the Year Ended December 31, 2006
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$ 969	$ 87	$ 501	$ 66	$1,623
Other	—	—	129	18	147
	969	87	630	84	1,770
Intersegment revenues	—	—	(21)	21	—
Total revenues	$ 969	$ 87	$ 609	$ 105	$1,770
Depreciation and amortization	$ (168)	$ (8)	$ (24)	$ (17)	$ (217)
Impairment and other charges	(110)	(9)	—	—	(119)
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 taxes					(421)
Income tax benefit					125
Loss from continuing operations					(296)
Loss from discontinued operations, net of taxes					(12)
Net loss					$ (308)
Identifiable assets:					
Domestic	$5,038	$440	$1,373	$1,215	$8,066
Other	—	—	13	57	70
Total	$5,038	$440	$1,386	$1,272	$8,136
Capital expenditures	$ (101)	$ (24)	$ (22)	$ (8)	$ (155)

Note 23—Quarterly Financial Information (Unaudited)

The following is a summary of Dynegy's unaudited quarterly financial information for the years ended December 31, 2008 and 2007:

	Quarter Ended			
	March 2008	June 2008	September 2008	December 2008
	(in millions, except per share data)			
Revenues	$ 545	$ 323	$1,886	$ 795
Operating income (loss)	(150)	(364)	1,116	107
Net income (loss) before cumulative effect of change in accounting principles	(152)	(272)	605(1)	(7)(2)
Net income (loss)	(152)	(272)	605(1)	(7)(2)
Net income (loss) per share	$(0.18)	$(0.32)	$ 0.72(1)	$(0.01)(2)

(1) Includes a gain on the sale of the Rolling Hills power generation facility of $56 million. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Rolling Hills for further information.

(2) Includes an impairment of our Heard County power generation facility of $47 million. Please read Note 5—Impairment Charges—Asset Impairments for further information. Includes a loss on the dissolution of DLS Power Development of $47 million and an impairment of our investment in DLS Power Development of $24 million. Please read Note 12—Variable Interest Entities—DLS Power Holdings and DLS Power Development for further information. Also includes translation gains related to the substantial liquidation of a foreign entity of $24 million.

	Quarter Ended			
	March 2007	June 2007	September 2007	December 2007
	(in millions, except per share data)			
Revenues	$ 505	$ 828	$1,046	$ 724
Operating income	81	182	247	95
Net income (loss) before cumulative effect of change in accounting principles	14	76(1)	220(2)	(46)
Net income (loss)	14	76(1)	220(2)	(46)(3)
Net income (loss) per share before cumulative effect of change in accounting principles	$0.03	$0.09(1)	$ 0.26(2)	$(0.06)(3)
Net income (loss) per share	$0.03	$0.09(1)	$ 0.26(2)	$(0.06)(3)

(1) Includes a gain related to a change in the fair value of interest rate swaps, net of minority interest of $30 million and a gain related to the settlement of the Kendall tolling arrangement of $31 million.

(2) Includes a gain on the sale of the CoGen Lyondell power generation facility of $210 million. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—GEN-WE Discontinued Operations—CoGen Lyondell for further information.

(3) Includes tax expense resulting from an increase in Dynegy's estimated state tax rate of approximately $50 million. Also includes a gain related to the sale of a portion of our interest in the Plum Point Project of $39 million.

The following is a summary of DHI's unaudited quarterly financial information for the years ended December 31, 2008 and 2007:

	Quarter Ended			
	March 2008	June 2008	September 2008	December 2008
	(in millions, except per share data)			
Revenues	$ 545	$ 323	$1,886	$795
Operating income (loss)	(150)	(364)	1,116	107
Net income (loss) before cumulative effect of change in accounting principles	(153)	(269)	606(1)	24(2)
Net income (loss)	(153)	(269)	606(1)	24(2)

(1) Includes a gain on the sale of the Rolling Hills power generation facility of $56 million. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Rolling Hills for further information.
(2) Includes an impairment of our Heard County power generation facility of $47 million. Please read Note 5—Impairment Charges—Asset Impairments for further information. Includes translation gains related to the substantial liquidation of a foreign entity of $24 million.

	Quarter Ended			
	March 2007	June 2007	September 2007	December 2007
	(in millions, except per share data)			
Revenues	$505	$828	$1,046	$724
Operating income	98	184	247	95
Net income (loss) before cumulative effect of change in accounting principles	22	90(1)	222(2)	(10)(3)
Net income (loss)	22	90(1)	222(2)	(10)(3)

(1) Includes a gain related to a change in the fair value of interest rate swaps, net of minority interest of $30 million and a gain related to the settlement of the Kendall tolling arrangement of $31 million.
(2) Includes a gain on the sale of the CoGen Lyondell power generation facility of $210 million. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—GEN-WE Discontinued Operations—CoGen Lyondell for further information.
(3) Includes tax expense resulting from an increase in DHI's estimated state tax rate of approximately $25 million. Also includes a gain related to the sale of a portion of our interest in the Plum Point Project of $39 million.

Note 24—Subsequent Events

Effective January 1, 2009, Dynegy entered into an agreement with LS Associates to dissolve the two companies' development joint venture. Please read Note 11—Unconsolidated Investments—Equity Method Investments for further discussion.

On February 13, 2009, we entered into Amendment No. 3 to the Fifth Amended and Restated Credit Facility. Please read Note 15—Debt—Fifth Amended and Restated Credit Facility 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.

DEFINITIONS

As used in this Form 10-K, the abbreviations listed below have the following meanings:

ANPR	Advanced Notice of proposed rulemaking
APB	Accounting Principles Board
APIC	Additional paid-in-capital
ARB	Accounting Research Bulletin
ARO	Asset retirement obligation
BACT	Best Available Control Technology (air)
BART	Best Available Retrofit Technology
BTA	Best technology available (water intake)
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAISO	The California Independent System Operator
CAVR	The Clean Air Visibility Rule
CERCLA	The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CO_2	Carbon dioxide
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CRA	Canada Revenue Authority
CRM	Our customer risk management business segment
DHI	Dynegy Holdings Inc., Dynegy's primary financing subsidiary
DMG	Dynegy Midwest Generation
DMSLP	Dynegy Midstream Services L.P.
DMT	Dynegy Marketing and Trade
DNE	Dynegy Northeast Generation
DPM	Dynegy Power Marketing Inc
EAB	The Environmental Appeals Board of the U.S. Environmental Protection Agency
EBITDA	Earnings before interest, taxes, depreciation and amortization
EITF	Emerging Issues Task Force
ERISA	The Employee Retirement Income Security Act of 1974, as amended
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIP	Federal Implementation Plan
FSP	FASB Staff Position
FTC	U.S. Federal Trade Commission
FTR	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles of the United States of America
GEN	Our power generation business
GEN-MW	Our power generation business—Midwest segment
GEN-NE	Our power generation business—Northeast segment
GEN-SO	Our power generation business—South segment, which was renamed GEN-WE
GEN-WE	Our power generation business—West segment
GHG	Greenhouse gas

ICAP	Installed capacity
ICC	Illinois Commerce Commission
IMA	In-Market Availability
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator—New England
LBH	Lehman Brothers Holdings Inc.
LMP	Locational Marginal Pricing
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MACT	Maximum Available Control Technology
MISO	Midwest Independent Transmission System Operator
MGGA	Midwest Greenhouse Gas Accord
MGGRP	Midwestern Greenhouse Reduction Program
MMBtu	Millions of British thermal units
MRTU	Market Redesign and Technology Upgrade
MW	Megawatts
MWh	Megawatt hour
NERC	North American Electric Reliability Council
NGL	Our natural gas liquids business segment
NOL	Net operating loss
NO_x	Nitrogen oxide
NYISO	New York Independent System Operator
NYDEC	New York Department of Environmental Conservation
OCI	Other Comprehensive Income
OTC	Over-the-counter
PCAOB	Public Company Accounting Oversight Board (United States)
PJM	PJM Interconnection, LLC
PPA	Power purchase agreement
PPEA	Plum Point Energy Associates
PRB	Powder River Basin coal
PSD	Prevention of Significant Deterioration
PURPA	The Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RCRA	The Resource Conservation and Recovery Act of 1976, as amended
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SAB	SEC Staff Accounting Bulletin
SCEA	Sandy Creek Energy Associates, LP
SCH	Sandy Creek Holdings, LLC
SEC	U.S. Securities and Exchange Commission
SERC	Southeastern Electric Reliability Council
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SPE	Special Purpose Entity

SPDES	State Pollutant Discharge Elimination System
SPN	Second Priority Senior Secured Notes
TARP	Troubled Assets Relief Program
TCEQ	Texas Commission on Environmental Quality
U.S. EPA	United States Environmental Protection Agency
VaR	Value at Risk
VIE	Variable Interest Entity
VLGC	Very large gas carrier
WAPA	Western Area Power Administration
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

DYNEGY INC.

CONDENSED BALANCE SHEETS OF THE REGISTRANT
(in millions)

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 22	$ 35
Intercompany accounts receivable	534	1,756
Short term investments	1	—
Deferred income taxes	6	45
Total Current Assets	563	1,836
Other Assets		
Investments in affiliates	7,369	6,101
Unconsolidated investments	15	61
Deferred income taxes	—	6
Total Assets	$ 7,947	$ 8,004
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 19	$ 5
Intercompany accounts payable	2	—
Other current liabilities	1	—
Total Current Liabilities	22	5
Intercompany long-term debt	2,244	2,243
Deferred income taxes	1,166	1,250
Total Liabilities	3,432	3,498
Commitments and Contingencies (Note 3)		
Stockholders' Equity		
Class A Common Stock, $0.01 par value, 2,100,000,000 shares authorized at December 31, 2008 and December 31, 2007; 505,821,277 shares and 502,819,794 shares issued and outstanding at December 31, 2008 and December 31, 2007, respectively	5	5
Class B Common Stock, $0.01 par value, 850,000,000 shares authorized at December 31, 2008 and December 31, 2007; 340,000,000 shares issued and outstanding at December 31, 2008 and December 31, 2007, respectively	3	3
Additional paid-in capital	6,485	6,463
Subscriptions receivable	(2)	(5)
Accumulated other comprehensive income (loss), net of tax	(215)	(25)
Accumulated deficit	(1,690)	(1,864)
Treasury stock, at cost, 2,568,286 shares and 2,449,259 shares at December 31, 2008 and December 31, 2007, respectively	(71)	(71)
Total Stockholders' Equity	4,515	4,506
Total Liabilities and Stockholders' Equity	$ 7,947	$ 8,004

See Notes to Registrant's Financial Statements and Dynegy Inc.'s Consolidated Financial Statements

DYNEGY INC.

CONDENSED STATEMENTS OF OPERATIONS OF THE REGISTRANT
(in millions)

	Year Ended December 31,		
	2008	2007	2006
Operating loss	$—	$ —	$ —
Earnings (losses) from unconsolidated investments	249	503	(452)
Interest expense	—	—	(6)
Debt conversion costs	—	—	(46)
Other income and expense, net	1	3	9
Income (loss) before income taxes	250	506	(495)
Income tax (expense) benefit	(76)	(242)	162
Net income (loss)	174	264	(333)
Less: preferred stock dividends	—	—	9
Net income (loss) applicable to common stockholders	$174	$ 264	$(342)

See Notes to Registrant's Financial Statements and Dynegy Inc.'s Consolidated Financial Statements

DYNEGY INC.

CONDENSED STATEMENTS OF CASH FLOWS OF THE REGISTRANT
(in millions)

	Year Ended December 31,		
	2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Operating cash flow, exclusive of intercompany transactions	$—	$ 8	$ 14
Intercompany transactions	3	46	59
Net cash provided by operating activities	3	54	73
CASH FLOWS FROM INVESTING ACTIVITIES:			
Unconsolidated investments	(16)	(10)	—
Loans to DHI	—	—	120
Business acquisitions, net of cash acquired	—	(128)	(8)
Short term investments	(2)	—	—
Net cash provided by (used in) investing activities	(18)	(138)	112
CASH FLOWS FROM FINANCING ACTIVITIES:			
Debt conversion costs	—	—	(46)
Redemption of Series C Preferred	—	—	(400)
Proceeds from issuance of capital stock	2	4	183
Dividends and other distributions, net	—	—	(17)
Other financing, net	—	(6)	—
Net cash provided by (used in) financing activities	2	(2)	(280)
Net decrease in cash and cash equivalents	(13)	(86)	(95)
Cash and cash equivalents, beginning of period	35	121	216
Cash and cash equivalents, end of period	$ 22	$ 35	$ 121
SUPPLEMENTAL CASH FLOW INFORMATION			
Interest paid (net of amount capitalized)	—	—	5
Taxes paid (net of refunds)	23	48	9
SUPPLEMENTAL NONCASH FLOW INFORMATION			
Conversion of Convertible Subordinated Debentures due 2023	—	—	225
Contribution of Sandy Creek to DHI	—	(16)	—

See Notes to Registrant's Financial Statements and Dynegy Inc.'s Consolidated Financial Statements

DYNEGY INC.

NOTES TO REGISTRANT'S FINANCIAL STATEMENTS

Note 1—Background and Basis of Presentation

These condensed parent company financial statements have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X, as the restricted net assets of Dynegy Inc.'s subsidiaries exceeds 25 percent of the consolidated net assets of Dynegy Inc. These statements should be read in conjunction with the Consolidated Statements and notes thereto of Dynegy Inc.

We are a holding company and conduct substantially all of our business operations through our subsidiaries. We began operations in 1985 and became incorporated in the State of Delaware in 2007 in anticipation of our April 2007 merger with the Contributed Entities.

Note 2—Commitments and Contingencies

For a discussion of our commitments and contingencies, please read Note 19—Commitments and Contingencies of our consolidated financial statements.

Please read Note 15—Debt of our consolidated financial statements and Note 19—Commitments and Contingencies—Guarantees and Indemnifications of our consolidated financial statements for a discussion of our guarantees.

Schedule II

DYNEGY INC.

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2008, 2007 and 2006

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
2008					
Allowance for doubtful accounts	$ 20	$ 4	$ (2)	$—	$ 22
Allowance for risk-management assets (1)	11	—	(11)	—	—
Deferred tax asset valuation allowance	62	(2)	—	(23)(6)	37
2007					
Allowance for doubtful accounts	$ 48	$ (3)	$ (21)(5)	$ (4)	$ 20
Allowance for risk-management assets (1)	—	11	—	—	11
Deferred tax asset valuation allowance	69	(6)	(1)	—	62
2006					
Allowance for doubtful accounts	$103	$ (35)(2)	$ 43(3)	$ (63)(4)	$ 48
Allowance for risk-management assets (1)	10	—	—	(10)	—
Deferred tax asset valuation allowance	70	17	—	(18)	69

(1) Changes in price and credit reserves related to risk-management assets are offset in the net mark-to-market income accounts reported in revenues. In connection with adopting SFAS No. 157, "Fair Value Measurement" on January 1, 2008, our price and credit reserves related to risk management assets were no longer considered allowances as they are included in the fair value measurement of our derivative contracts.

(2) Primarily represents the reversal of previously reserved receivables associated with a foreign entity. Dynegy revised its estimate of the uncollectible portion of these receivables. The charges are included in bad debt expense or discontinued operations, depending on the nature of the underlying receivable, and are reflected on our consolidated statements of operations.

(3) Primarily represents the establishment of an allowance for doubtful accounts on a foreign entity.

(4) Primarily represents the write-off off an uncollectible receivable associated with a foreign entity, which was previously reserved, as a result of a bankruptcy settlement. As a result, Dynegy reduced its allowance for doubtful accounts and reduced the corresponding accounts receivable.

(5) Primarily represents a partial reversal of the allowance for doubtful accounts on a foreign entity as a result of a bankruptcy settlement, as such amount will be collected.

(6) Primarily represents the release of valuation allowance associated with foreign tax credits, which were previously reserved.

DYNEGY HOLDINGS INC.

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2008, 2007 and 2006

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
2008					
Allowance for doubtful accounts	$ 15	$ 5	$—	$—	$ 20
Allowance for risk-management assets (1)	11	—	(11)	—	—
Deferred tax asset valuation allowance	59	(2)	—	(20)(6)	37
2007					
Allowance for doubtful accounts	$ 48	$ (3)	$ (21)(5)	$ (9)	$ 15
Allowance for risk-management assets (1)	—	11	—	—	11
Deferred tax asset valuation allowance	66	(6)	(1)	—	59
2006					
Allowance for doubtful accounts	$103	$ (35)(2)	$ 43(3)	$ (63)(4)	$ 48
Allowance for risk-management assets (1)	10	—	—	(10)	—
Deferred tax asset valuation allowance	52	4	15	(5)	66

(1) Changes in price and credit reserves related to risk-management assets are offset in the net mark-to-market income accounts reported in revenues. In connection with adopting SFAS No. 157, "Fair Value Measurements" on January 1, 2008, our price and credit reserves related to risk management assets were no longer considered allowances as they are included in the fair value measurement of our derivative contracts.

(2) Primarily represents the reversal of previously reserved receivables associated with a foreign entity. DHI revised its estimate of the uncollectible portion of these receivables. The charges are included in bad debt expense or discontinued operations, depending on the nature of the underlying receivable, and are reflected on our consolidated statements of operations.

(3) Primarily represents the establishment of an allowance for doubtful accounts on a foreign entity.

(4) Primarily represents the write-off off an uncollectible receivable associated with a foreign entity, which was previously reserved, as a result of a bankruptcy settlement. As a result, DHI reduced its allowance for doubtful accounts and reduced the corresponding accounts receivable.

(5) Primarily represents a partial reversal of the allowance for doubtful accounts on a foreign entity as a result of a bankruptcy settlement, as such amount will be collected.

(6) Primarily represents the release of valuation allowance associated with foreign tax credits, which were previously reserved.

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