DYNEGY

2009
Annual Report

FINANCIAL HIGHLIGHTS

($ in millions, except per share amounts)	Year Ended December 31, 2009	2008	2007
FINANCIAL DATA			
Operating revenues	$2,468	$3,324	$2,918
Power Generation - Midwest operating income (loss)	(4)	686	498
Power Generation - West operating income (loss)	(218)	123	98
Power Generation - Northeast operating income (loss)	(444)	67	164
Operating income (loss)	(834)	744	576
Income (loss) from discontinued operations, net of tax	(222)	(17)	166
Net income (loss)	(1,262)	171	271
Net income (loss) attributable to Dynegy Inc.	(1,247)	174	264
Capital expenditures, investments and acquisitions	594	640	504
Cash flow provided by operations	135	319	341
Total long-term debt and obligations	6,220	6,823	6,741
COMMON SHARE DATA			
Earnings (loss) per diluted common share attributable to Dynegy Inc.	(1.52)	$0.20	$0.35
Annual cash divided per common share*	-	-	-
Market price at year-end	1.81	2.00	7.14
Average common shares outstanding (in millions)			
Diluted	826	842	754
Basic	822	840	752
OPERATING STATISTICS			
Power Generation - Midwest			
Electric power generated (net million megawatt hours)	25	24	25
Power Generation - West			
Electric power generated (net million megawatt hours)	6	9	8
Power Generation - Northeast			
Electric power generated (net million megawatt hours)	10	8	9

* 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 represents 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 23 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:

The electricity sector faced a unique set of challenges in 2009. Natural gas prices started the year below $4 per million BTUs and advanced only modestly during 2009, resulting in lower electricity prices. The U.S. recession dampened demand for electricity, as did milder than usual summer weather in parts of the country. Wall Street turmoil took its toll on the sector as well, drying up liquidity by sidelining a number of financial market participants. Additionally, weak credit markets restricted M&A activity in the power sector.

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.

In the face of these challenges, Dynegy continued to operate well, commercialize well and work proactively to position itself for the future. We were obviously impacted by weak economic and power market conditions that began in mid-2008. However, we held to a set of core beliefs that guides our business through the various commodity cycles. As a result, we weathered the tumultuous economic and market conditions of 2009. Today, we are positioned to provide benefits for our investors as power markets improve over the longer term.

The core beliefs that guide our business are:

- 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.

The last core belief refers to the link between the two sides of the balance sheet – the left, or the asset-based side, and the right, or the capital-based side. To operate and commercialize our assets effectively, we rely on capital-based strategies that are designed to provide adequate liquidity and help us prepare for future credit events. To that end, we are constantly fine-tuning our capital structure with a focus on supporting our operational and commercial objectives in the face of external market conditions.

In August we announced a series of strategic transactions that represent a long-term investment in our future. In this year's letter to investors, I will discuss those transactions, then provide an update on how we performed in terms of our commercial, operational and environmental initiatives. I will touch on our view of the industry, and finally I will cover our value proposition for investors.

Strategic Achievements

The strategic transactions we completed in 2009 resulted from long-standing discussions among our Executive Management Team and Board of Directors. In the face of depressed economic and market conditions, the company's near-term debt maturities in 2011 and 2012 represented a potential challenge for our company. We needed to ensure there was ample liquidity to run our business in a lingering low commodity price environment. At the same time, we did not want to sacrifice the diversity of our power generation portfolio. And finally, our

2009 Strategic Transactions

- Amendment to secured credit facilities
- Major asset transaction
- Companywide cost-savings initiative
- Liability management program to reduce near-term debt

Class B ownership structure presented challenges due to the potentially divergent interests and investment horizons that are characteristic of public and private ownership.

The solution was a series of transactions that ended with the repurchase of the majority of our 2011 and 2012 bond maturities. Prior to launching our liability management initiative, we sought and received an amendment to our secured credit facilities that provided greater flexibility to repurchase bonds. This was followed by a transaction with LS Power in which we received approximately $1 billion in cash and 245 million of Class B shares.

The transaction reduced LS Power's shareholdings from approximately 40 percent of our outstanding shares to approximately 15 percent, and eliminated LS Power's special approval and blocking rights and board representation. In exchange, LS Power received five natural gas-fired peaking facilities, three combined-cycle facilities and Dynegy's remaining interest in the Sandy Creek construction project. LS Power also received $235 million face value of our 2015 senior unsecured notes on terms identical to the existing 2015 bonds, which have no restrictive covenants.

The benefits of the transaction extend to several levels. The company was able to redeem approximately 30 percent of its outstanding shares and eliminate the dual-class stock structure associated with LS Power's ownership. This resulted in a streamlined, 100 percent publicly held share ownership structure for the first time in Dynegy's history.

While our nameplate generating capacity was reduced by approximately 4,800 megawatts, our portfolio remains balanced in terms of geography, fuel and dispatch. Approximately 60 percent of the megawatts traded were simple-cycle units, which only run in peak demand periods. We are now more weighted toward baseload coal and natural gas combined-cycle plants with an improved ratio of "productive megawatts."

	Megawatts	Gas	Coal	Oil	Plants	States	Regions
Midwest*	5,456	36%	60%	4%	10	IL, PA, AR	MISO, PJM, SERC
West	3,696	96%	0%	4%	5	CA, NV	CAISO, WECC
Northeast	3,282	53%	11%	36%	4	NY, ME	NYISO, ISO-NE
Total	12,434	57%	29%	14%			

*Includes Dynegy's interest in Plum Point construction project in Arkansas

The proceeds we received from the transaction provided a platform for an aggressive liability management plan targeting near-term bond maturities. At the end of the year, Dynegy Holdings Inc. completed the funding of the repurchase of approximately $420 million of its outstanding 6.875 percent Senior Unsecured Notes due 2011 and approximately $410 million of its outstanding 8.75 percent Senior Unsecured Notes due 2012. This represents 83 percent of the company's Senior Unsecured Notes due 2011 and 2012. The bottom line is that our bond maturities profile has improved dramatically.

In addition, Dynegy launched an aggressive cost savings initiative with anticipated total savings estimated at $400-$450 million over a four-year period beginning in 2010. Annual savings are expected to be generated through reduced capital, operational and general and administrative expenditures. Our intent is to reduce costs without compromising safety or performance at our plants, and we believe we can accomplish this in several ways. To reduce capital expenditures, we are postponing non-essential outages while maintaining safety and performance, and we are continuing to target no less than 90 percent in-market availability for our baseload fleet. To reduce corporate overhead, we implemented a range of cost-saving measures, including a workforce reduction in 2009 and other general and administrative-related savings.

Financial strength and strategic flexibility have always been the foundations of our strategy. By amending our credit facility, restructuring our stockholder base, bringing in approximately $1 billion in cash, initiating a cost-savings program and taking steps to improve our bond maturities profile, we demonstrated our commitment to running our business soundly and in a manner that positions the company and its investors for the future.

2009 Highlights

Operational performance – During 2009, our 1,600-plus Operations employees continued to focus on safe, reliable and low-cost operations. Our safety record in 2009 was one of the best of the decade – a result of our efforts to ensure that safety records are driven by safety attitudes and behaviors rather than one-time programs. Our key reliability benchmark of in-market availability tracked above 90 percent for our baseload coal fleet and more than 98 percent for our natural gas combined-cycle facilities. In addition, we again demonstrated a strong track record of compliance with both environmental and North American Electric Reliability Corporation requirements. We achieved all of this within our targeted budgets.

Commercial performance – Dynegy continued to improve its commercial execution in 2009 by utilizing our near-term hedging strategy. We believe our strategy gives us the best opportunity to capture intrinsic and extrinsic value from our assets and increase the predictability of earnings and cash flow, while optimizing the balance of risk and reward. Relating to this strategy, we volumetrically hedge expected generation over the next 12-36 months through commercial arrangements that include tolling agreements, financial swaps, collars and options. We have volumetrically hedged a substantial portion of our expected generation through 2011. In the outer years, we remain substantially open to capitalize on expected improvements in economic and market conditions. We believe the implementation and execution of this commercial strategy allowed us to capture significant value during 2009.

Environmental performance – Dynegy continued to make progress on its multi-year environmental investment in the Midwest. This includes investments in baghouses, dry scrubbers and mercury control projects at eight of the company's coal-fired units in Illinois. During 2009, work was completed on a baghouse, dry scrubber and other equipment at the Havana Power Station. Additional baghouse and scrubber projects are under way at three units at the Baldwin Energy Complex, with completion anticipated in 2013. Combined with Dynegy's earlier statewide conversion to low-sulfur coal, the company's environmental investments in Illinois are expected to result in reductions of nitrogen oxides, sulfur dioxide and mercury of approximately 90 percent, as well as significant drops in particulate matter and other emissions. We view these investments as a competitive advantage that positions our coal fleet for long-term viability in a climate marked by increasingly stringent environmental standards.

Some of our other environmental programs are focused on reducing carbon dioxide (CO2), the chemical compound frequently associated with climate change. In the lower Mississippi River Valley, Dynegy has partnered with the U.S. Fish & Wildlife Service to restore more than 45,000 acres of hardwood forests – an initiative that creates a haven for wildlife while sequestering CO_2. Another example relates to the work we are doing with Calera Corp. in Monterey, California, to channel flue gas emissions from our Moss Landing facility to make a material similar to Portland cement. If perfected on a commercial scale, the process would offer two-fold benefits: a means of capturing CO_2 and creating a beneficial, marketable product with positive benefits in the building sector.

Our Industry View

While a number of external factors have the potential to influence our business, we remain focused on understanding these challenges, planning contingencies and developing solutions to help mitigate their impact.

One major market concern is the demand for power and the ongoing weakness in the energy commodity markets. During 2009, U.S. electric demand was down approximately 4 percent. However, the Energy Information Administration is forecasting demand growth of approximately 2 percent per year for 2010 and 2011 as the economy improves and summer temperatures return to more typical levels compared to 2009.

Despite low market prices, our generation volumes were nearly flat in 2009, which can be attributed to our fleet diversity and emphasis on high in-market availability levels. This enabled us to serve our markets when opportunities arose.

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

Turning now to the supply side of the equation, across the country only a handful of new baseload plants are being built today. Given the slowdown of development and construction activities, we believe that new generation will come online at a slower rate in the near future due to very high barriers to entry in a capital-intensive industry.

As for long-term industry fundamentals, we believe that power prices should increase as supply and demand tighten and natural gas prices rise over time. In addition, we believe rising costs and new environmental regulations could push less-efficient generation into retirement. Looking at our own generation assets, two of Dynegy's strengths are the environmental investments we are making to our Midwest coal-fired units and the diversity afforded by our natural gas combined-cycle fleet. We believe the investments in cleaner technologies combined with fleet diversity help position us for long-term viability.

Another external factor is the uncertainty around carbon legislation. Dynegy's position is that since climate change is a global issue, any regulation of greenhouse gas sources in the U.S. should be undertaken by the federal government in coordination with developed and developing countries around the world.

Our preference would be for overarching federal legislation with federal preemption – not a patchwork of state and regional regulations – that addresses the three critical, interrelated elements central to this debate:

- The environment;
- The economy, which remains in a state of recovery; and
- Energy security and reliability.

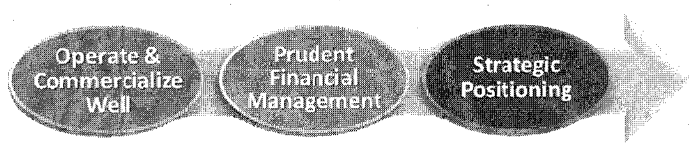
While we have seen a number of proposals from Washington, D.C., certainty on this issue is lacking. At this point, no one really knows which regulations will be passed, if any, what they will ultimately look like or when they will become effective. Further, some of the reports relative to environmental legislation or rulemakings are based on "worst case" scenarios which may or may not become reality.

The bottom line is that we will maintain our diligence in monitoring the risk factors that can potentially impact our business, and we will continue to provide appropriate disclosures as these risks are identified. We will also actively manage our operational portfolio, commercial practices and capital structure to take advantage of market opportunities while mitigating risks.

Our Value Proposition for Investors

Dynegy is a manufacturing company in the sense that we take a raw material – in our case, natural gas, coal or fuel oil – and use it to produce a product: electricity. Like a number of other manufacturers with a focus on creating long-term value for investors, we are committed to three key objectives: operating and commercializing well; managing the right-hand or capital side of the balance sheet; and strategically positioning the company for long-term results.

Dynegy's Objectives for Creating Long-term Value



In closing, I would like to demonstrate how we are meeting each of these objectives. In terms of operating and commercializing well, our asset diversity helps us manage many of the risks inherent to our business. We continue to maximize cash flows by maintaining a low-cost, reliable operating platform. And, our commercial strategy remains open to harvest value as supply and demand are expected to tighten over the longer term.

Relating to prudent financial management, we demonstrated in 2009 the ongoing proactive management of our capital structure to facilitate our commercial strategy. We are committed to maintaining a simple, flexible capital structure, and we have largely eliminated a significant portion of our bond maturities until 2015. We are also driving down costs through a multi-year cost savings program.

Finally, we have eliminated our dual-class stock structure and simplified our stock structure to the extent that all outstanding equity is now publicly held for the first time in our 26-year history. This provides strategic flexibility to participate in the future consolidation of the industry. We have long held, and we continue to believe, that industry consolidation remains an attractive proposition based on the significant synergies and cost savings that can be achieved through combinations.

In summary, our diligence and success at meeting these objectives help position us to capture value for stockholders as power markets improve over the longer term.

I thank you for your interest and look forward to seeing many of you at our Annual Meeting of Stockholders on May 21 in Houston. For more about our company, I encourage you to visit our web site at www.dynegy.com.

Bruce A. Williamson
Chairman, President and Chief Executive Officer
February 25, 2010

BOARD OF DIRECTORS

David W. Biegler, 63

Mr. Biegler is the Chairman and Chief Executive Officer of Southcross Energy, LLC and also currently serves as Chairman of Estrella Energy, L.P., an investor in Southcross. 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., Animal Health International, Inc. and Children's Medical Center. Mr. Biegler has served as a Dynegy Director since 2003. (2)

Thomas D. Clark, Jr., 69

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)

Victor E. Grijalva, 71

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)

Patricia A. Hammick, 63

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.

George L. Mazanec, 73

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)

Howard B. Sheppard, 64

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)

William L. Trubeck, 63

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 and WellCare Health Plans, Inc. In addition, he is Vice Chairman of the Board of Trustees of Monmouth College in Illinois. He has served as a Dynegy Director since 2003. (1,2)

Bruce A. Williamson, 50

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

EXECUTIVE MANAGEMENT TEAM

Bruce A. Williamson, 50

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, 38

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, 45

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.

Lynn A. Lednicky, 49

Executive Vice President of Operations. He is responsible for the operational management of Dynegy's fleet of power generation assets. Mr. Lednicky joined Dynegy predecessor Destec Energy, Inc. in 1991.

Holli C. Nichols, 39

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

www.dynegy.com

Stock Exchange and Certification Information

In 2009, 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 2009 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 21, 2010.

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, 2009

☐ **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 Section12(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 Section12(g) of the Act:

None
(Title of Class)

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 such filing requirements for the past 90 days.

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

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 the definitions 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 (Do not check if a smaller reporting company)	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, 2009, the aggregate market value of the Dynegy Inc. common stock held by non-affiliates of the registrant was $1,144,695,131 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, 601,240,118 shares outstanding as of February 19, 2010; Class B common stock, $0.01 par value, zero shares outstanding as of February 19, 2010. 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 2010 Annual Meeting of Stockholders, which the registrant intends to file not later than 120 days after December 31, 2009.

REDUCED DISCLOSURE FORMAT-Dynegy Holdings Inc. Dynegy Holdings Inc. meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and therefore is filing this Form 10-K with the reduced disclosure format.

DYNEGY INC. and DYNEGY HOLDINGS INC.

FORM 10-K

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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, 2009 and constituting approximately 100 percent of Dynegy's total consolidated asset base as of December 31, 2009.

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.

PART I

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
CAISO	The California Independent System Operator
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CAVR	The Clean Air Visibility Rule
CCB	Coal combustion byproducts
CERCLA	The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CO_2	Carbon dioxide
CO_2e	The climate change potential of other GHGs relative to the global warming potential of CO_2
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CRM	Our former customer risk management business segment
CWA	Clean Water Act
CUSA	Chevron U.S.A. Inc.
DHI	Dynegy Holdings Inc., Dynegy's primary financing subsidiary
DMSLP	Dynegy Midstream Services L.P.
DMT	Dynegy Marketing and Trade
DNE	Dynegy Northeast Generation
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
EPA	United States Environmental Protection Agency
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-WE	Our power generation business—West segment
GHG	Greenhouse gas
HAPs	Hazardous air pollutants, as defined by the Clean Air Act
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
LMP	Locational Marginal Pricing
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTIP	Long-Term Incentive Plan
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
NPDES	National Pollutant Discharge Elimination System
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
SCEA	Sandy Creek Energy Associates, LP
SCH	Sandy Creek Holdings, LLC
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SPDES	State Pollutant Discharge Elimination System
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

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 eighteen operating power plants in six states totaling approximately 12,300 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. 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) 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 power 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 power 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 Power Generation Portfolio

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
Vermilion Units 1-2	164	Coal/Gas	Baseload	Oakwood, IL	MISO
Unit 3	12	Oil	Peaking	Oakwood, IL	MISO
Wood River (2)	446	Coal	Baseload	Alton, IL	MISO
Total Midwest	*5,316*				
Moss Landing Units 1-2	1,020	Gas	Intermediate	Monterey County, CA	CAISO
Units 6-7	1,509	Gas	Peaking	Monterey County, CA	CAISO
Morro Bay (3)	650	Gas	Peaking	Morro Bay, CA	CAISO
South Bay (4)	309	Gas	Peaking	Chula Vista, CA	CAISO
Oakland	165	Oil	Peaking	Oakland, CA	CAISO
Black Mountain (5)	43	Gas	Baseload	Las Vegas, NV	WECC
Total West	*3,696*				
Independence	1,064	Gas	Intermediate	Scriba, NY	NYISO
Roseton (6)	1,185	Gas/Oil	Peaking	Newburgh, NY	NYISO
Casco Bay	540	Gas	Intermediate	Veazie, ME	ISO-NE
Danskammer Units1-2	123	Gas/Oil	Peaking	Newburgh, NY	NYISO
Units 3-4 (6)	370	Coal/Gas	Baseload	Newburgh, NY	NYISO
Total Northeast	*3,282*				
Total Fleet Capacity	*12,294*				

(1) Unit capabilities are based on winter capacity.
(2) Represents Units 4 and 5 generating capacity. Units 1-3, with a combined net generating capacity of 119 MW, are currently in lay-up status and out of operation
(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) Represents Units 1 and 2 and the combustion turbine generating capacity. Units 3 and 4, with a combined net generating capacity of 395 MW, were permanently retired on December 31, 2009.
(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.

Our Strategy

Our business strategy seeks to create stockholder value through:

- a diverse portfolio of power generation assets;
- a diverse commercial strategy that includes buying and selling electric energy, capacity and ancillary services either short-, medium- or long-term and sales and purchases of emissions credits, fuel supplies and transportation services. In addition, our short- and medium-term strategy attempts to capture the extrinsic value inherent in our portfolio. We seek to strike a balance between contracting for short- and medium-term stability of earnings and cash flows while maintaining unhedged volumes to capitalize on expected increases in commodity prices in the longer term;
- safe, low cost plant operations, with a focus on having our plants available and "in the market" when it is economical to do so; and
- a simple, flexible capital structure to support our business and commercial operations and to position us to pursue industry consolidation opportunities.

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 generally low-cost and economically attractive to dispatch around the clock throughout the year. A baseload facility is usually expected to run in excess of 70 percent of the hours in a given year. Intermediate generation may not be as efficient and/or economical as baseload generation, but is typically 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.

Power prices have significantly declined since the summer of 2008. This decline reflects a similar decline in natural gas prices and the impact of general economic conditions, including a recessionary environment that has negatively impacted the demand for electricity. Despite these effects, we continue to believe that, over the longer term, power demand and power pricing should increase. As a result, 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 higher margins over time. We anticipate that our combined cycle units also should benefit from increased run-times as heat rates expand, with improved margins and cash flows as demand increases in our key markets.

In addition, we believe that our portfolio of assets helps to mitigate certain risks inherent in our business. For example, weather patterns, regulatory regimes and commodity prices often differ by region and state. By maintaining geographic diversity, we lessen the impact of an individual risk in any one region and are better positioned to improve the level and consistency of our earnings and cash flows.

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 our generating assets increase in value through improved cash flows and earnings as capacity utilization and power prices improve. Given current market pricing and conditions, we see limited long-term attractive commercial arrangements.

We plan to continue to volumetrically hedge the expected output from our facilities over a rolling 1-3 year time frame 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 consistent with our efforts to improve predictability of short- and medium-term earnings and cash flows.

Our commercial strategy seeks to balance the goal of protecting cash flow in the short- and medium-term with maintaining the ability to capture value longer term as markets tighten. In order to maximize the value of our assets, we seek to capture intrinsic and extrinsic value. Opportunities to capture extrinsic value – that is, value beyond that ascribed to our generating capacity based solely on a current price strip – arise from time to time in the form of price volatility, differences in counterparties' views of forward prices and other activities. In order to execute our strategy, we utilize a wide range of products and contracts such as power purchase agreements, fuel supply contracts, capacity auctions, bilateral capacity contracts, power and natural gas swap agreements, power and natural gas options and other financial instruments.

We also seek to balance predictability of earnings and cash flow with achieving the highest level of earnings and cash flow. Short-term market volatility can negatively impact our profitability; we will seek to reduce those negative impacts through the disciplined use of short- and medium-term forward economic hedging instruments. Through the use of forward economic hedging instruments, including various products and contracts such as options and swaps, we seek to capture the extrinsic value inherent in our portfolio. Due to a number of variables – including changes in correlations between gas and power, time decay, changes in commodity prices, volatility and liquidity – we intend to actively and continuously balance our asset and hedge portfolios.

We expect to engage in less economic hedging activity beyond a three-year time frame in order to realize the anticipated benefit of improved market prices over time as the supply and demand balance tightens.

We set specific limits for "gross margin at risk" for our assets and economic hedges. These limits require power hedging above minimum levels, while requiring that corresponding fuel supplies are appropriately hedged as we progress through time. We also specifically attempt to manage basis risk to hubs that are not the natural sales hub for a facility and maintain focus on optimizing the commercial factors that we can control and mitigating commodity risk where appropriate and possible.

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, low-cost and environmentally compliant manner. By maintaining and operating our assets in an effort to ensure plant availability, high dispatch and capacity factors and an increased focus on operating and capital costs, we believe we are positioned to capture opportunities in the marketplace effectively and to maximize our operating margins.

Our power generation facilities are managed to require a relatively predictable level of maintenance capital expenditures without compromising operational integrity. Our capital expenditures are applied to the maintenance of our facilities to ensure their continued reliability and to 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 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.

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 seeks to capture the value associated with both medium- and long-term price trends. We seek to maintain a capital structure, including debt amounts and maturities, debt covenants and overall liquidity, that is suitable for our commercial strategy and the commodity cyclical market in which we operate.

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 our resources, as three separate segments in our consolidated financial statements: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. The results of our legacy operations, including CRM, are included in Other. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. Please read Note 24—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, 2009) 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 operating 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 most 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 reserves 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 dominance in these markets. NERC regions and RTOs/ISOs often have different geographic footprints, and while there may be geographic 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, 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 MWh 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 and/or less economical 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 will receive the location-based marginal price for their output. The location-based marginal price, absent congestion, would be the marginal price of the most expensive unit needed to meet demand. 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 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 MISO facilities was filed with the FERC in June 2009. The triennial market power review for our GEN-NE and PJM facilities was filed at FERC in August 2008. FERC issued an order accepting this filing in December 2008. The triennial market power reviews for our GEN-WE facilities will be filed pursuant to a FERC established schedule.

Power Generation—Midwest Segment

GEN-MW is comprised of eight facilities in Illinois and one in Pennsylvania with a total generating capacity of 5,316 MW. As of December 31, 2009, GEN-MW operated 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, 2009, we owned seven power generating facilities that sell into the MISO market and are located in Illinois, with an aggregate net generating capacity of 3,536 MW within MISO.

The MISO market 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 MISO. This system is "price-transparent", allowing generators and load serving entities to see real-time price effects of transmission constraints and impacts of generation and load changes to prices at each point. MISO operates day-ahead and real-time markets into which generators can offer to provide energy. MISO does not administer a centralized capacity market.

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 implemented an enforceable Planning Reserve Margin for each planning year effective June 1, 2009. 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, 2009, we owned two generating facilities that sell into the PJM market and are located in Illinois and Pennsylvania with an aggregate net generating capacity of 1,780 MW.

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. In addition to entering into bilateral capacity transactions, we have participated in RPM base residual auctions through PJM's planning year 2012-2013, which ends May 31, 2013, as well as ongoing incremental auctions to balance positions and offer residual capacity that may become available.

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 in MISO are a significant driver of our overall financial performance due to the fact that a significant portion of our total power generating capacity is located in MISO and is attributable to coal-fired baseload units. We commercialize these assets through a combination of bilateral physical and financial power, fuel and capacity contracts.

PJM. Our generation assets in PJM are natural gas-fired combined cycle intermediate dispatch facilities. We commercialize these assets through a combination of bilateral power, fuel and capacity contracts. We commercialize our capacity through either the RPM auction or on a bilateral basis. Additionally, as of December 31, 2009, approximately 280 MW of capacity at our Kendall facility was contracted under a tolling agreement through 2017. In January 2010, we executed an agreement to terminate the tolling arrangement.

Regulatory Considerations

In July 2007, legislative leaders in the State of Illinois announced a comprehensive transitional rate relief package that significantly altered the power procurement process and provided rate relief for electric consumers. The rate relief program provided approximately $1 billion to help provide assistance to utility customers in Illinois and fund the power procurement agency. As part of this rate relief package, we made payments totaling $25 million over a 29-month period with the final payment made in 2009.

MISO. Actual reserve margins are substantially above MISO's current required reserve margin of 15.4 percent and are increasing year over year, largely due to increased wind generation capacity and decreased demand. The reserve margin based on available capacity was 43.8 percent during the 2009 summer season as compared to 32 percent during the 2008 summer season.

PJM. Actual reserve margins are somewhat above PJM's current required installed reserve margin of 15 percent and are decreasing year over year. The reserve margin based on deliverable capacity was 19.67 percent for Planning Year 2009/10 as compared to 21.03 percent for Planning Year 2008/09. PJM's required installed reserve margin is increasing year over year, and will increase to 15.5 percent for Planning Year 2010/11.

Construction Project

Plum Point. We own an approximate 37 percent interest in PPEA Holding Company LLC ("PPEA Holding"), which, through its wholly owned subsidiary, PPEA, owns an approximate 57 percent undivided interest in the Plum Point Energy Station (the "Plum Point Project"), a 665 MW coal-fired power generation facility under construction in Mississippi County, Arkansas. The Plum Point Project is currently expected to commence commercial operations in 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. We consider our interest in PPEA Holding a non-core asset and intend to pursue alternatives regarding our remaining ownership interest.

Power Generation—West Segment

GEN-WE is comprised of four natural gas-fired power generation facilities located in California (3) and Nevada (1) and one fuel oil-fired power generation facility located in California, totaling 3,696 MW of electric generating capacity.

RTO/ISO Discussion

CAISO. CAISO covers approximately 90 percent of the State of California. At December 31, 2009, we owned four generating facilities in California within CAISO. The South Bay and Oakland facilities are designated as RMR units by the CAISO.

Contracted Capacity and Energy

CAISO. In CAISO, where our assets include intermediate dispatch and peaking facilities, we seek to mitigate spark spread variability through RMR, tolling arrangements and physical and financial bilateral power and fuel contracts. All of the capacity of our Moss Landing Units 6 and 7 and Morro Bay facility are contracted under tolling arrangements through 2013. Our Oakland and South Bay facilities operate under RMR contracts.

Regulatory Considerations

CAISO. CAISO launched its new market design, MRTU, in April 2009. MRTU provides more effective and transparent congestion management and a day-ahead market that co-optimizes energy and reserve procurement.

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.

The CPUC requires a Resources Adequacy margin of 15 to 17 percent. The actual reserve margin generally moves within, or close to, this range but seasonal and regional fluctuations exist.

Equity Investment

Black Mountain. We have a 50 percent indirect ownership interest in the Black Mountain facility, 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.

Power Generation—Northeast Segment

GEN-NE is comprised of four facilities located in New York (3) and Maine (1), with a total capacity of 3,282 MW. We own and operate the Independence, Casco Bay and Danskammer Units 1 and 2 power generating facilities, and we operate the Roseton and Danskammer Units 3 and 4 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 market in which GEN-NE resides is characterized by two interconnected and actively traded competitive markets: the NYISO (an ISO) and the ISO-NE (an RTO). In the GEN-NE 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 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, 2009, we operated three facilities within NYISO with an aggregate net generating capacity of 2,742 MW.

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 recover their investment 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 general sector in which it is needed most when that new capacity is needed. To calculate the price and quantity of installed capacity, three ICAP demand curves are utilized: one for Long Island, one for New York City and one for Statewide (commonly referred to as Rest of State). Our facilities operate in the Rest of State market.

Due to transmission constraints, energy prices vary across New York and are generally higher in the Southeastern part of New York, where our Roseton and Danskammer facilities are located, and in New York City and Long Island. Our Independence facility is located in the Northwest part of the state.

ISO-NE. The ISO-NE market includes the six New England states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. As of December 31, 2009, we owned and operated one power generating facility (Casco Bay) within the ISO-NE, with an aggregate net generating capacity of 540 MW. ISO-NE is in the process of implementing a FCM as described in more detail below.

Contracted Capacity and Energy

NYISO. We commercialize these assets through a combination of bilateral physical and financial power, fuel and capacity contracts.

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 LMP at Pleasant Valley. 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. This provides relatively stable capacity revenues at market prices from our facilities in the short-term and is expected to for the foreseeable future.

ISO-NE. Three forward capacity auctions have been held to date with capacity clearing prices ranging from $4.50 kW/month for the 2010/2011 market period to $2.95 kW/month for the 2012/2013 market period. These capacity clearing prices represent the floor price and the actual rate paid to market participants that were affected by pro-rationing due to oversupply conditions. The delivery of capacity under the forward capacity market will be fully effective on June 1, 2010.

Regulatory Considerations

NYISO. The actual amount of installed capacity is somewhat above NYISO's current required margin of 16.5 percent. FERC recently accepted a proposed increase in the required reserve margin to 18 percent in the New York Control Area, which is effective for the period of May 2010 through April 2011. This increase will require load-serving entities to procure more capacity relative to the load forecast; however, due to lower demand related to, among other things, weakness in the overall economy, the increase will likely result in little or no change in the capacity market.

ISO-NE. The ISO-NE is in the process of restructuring its capacity market and will be transitioning from a fixed payment structure to a forward capacity structure where capacity prices are determined through auctions. The delivery of capacity under the forward capacity market will be fully effective June 1, 2010. Discussions to address improvements with the forward capacity market design are currently underway by the ISO and its stakeholders.

The actual amount of installed capacity is significantly above the ISO-NE's current installed Capacity Requirement of 9.9%. ISO-NE, similar to other periods, has proposed an installed Capacity Requirement of 9.7% for the period of June 2010 through May 2011, which was accepted by FERC in February 2009. Generator additions, combined with increased demand response participation in the capacity market and weakness in the overall economy, will exert downward pressure on the capacity market.

Other

Corporate governance roles and functions, which are managed on a consolidated basis, and specialized support functions such as finance, accounting, commercial, risk control, tax, legal, regulatory, 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 legacy CRM operations, which primarily consist of a minimal number of power and natural gas trading positions, are also included in Other.

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 create unprofitable or unfavorable operating conditions or require significant capital and operating expenditures. Any 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, if at all. Further, changed interpretations of existing regulations may subject 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 $320 million in 2009 compared to approximately $245 million in 2008 and approximately $108 million in 2007. The 2009 expenditures include approximately $260 million for projects related to our Midwest Consent Decree (which is discussed below) compared to $215 million for Midwest Consent Decree projects in 2008. We estimate that total environmental expenditures in 2010 will be approximately $235 million, including approximately $200 million in capital expenditures and approximately $35 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 could create adverse operating conditions. Please read Note 21—Commitments and Contingencies for further discussion of this matter.

Climate Change

For the last several years, there has been a robust public debate about climate change and the potential for regulations requiring lower emissions of GHG, primarily CO_2 and methane. We believe that the focus of any federal program attempting to address climate change should include three critical, interrelated elements: (i) the environment, (ii) the economy and (iii) energy security.

We cannot confidently predict the final outcome of the current debate on climate change nor can we predict with confidence the ultimate requirements of proposed or anticipated federal and state legislation and regulations intended to address climate change. These activities, and the highly politicized nature of climate change, suggest a trend toward increased regulation of CO_2 that could result in a material adverse effect on our financial condition, results of operations and cash flows. Existing and anticipated federal and state regulations intended to address climate change may significantly increase the cost of providing electric power, resulting in far-reaching and significant impacts on us and others in the power generation industry over time. It is possible that federal and state actions intended to address climate change could result in costs assigned to GHG emissions that we would not be able to fully recover through market pricing or otherwise. If capital and/or operating costs related to compliance with regulations intended to address climate change become great enough to render the operations of certain plants uneconomical, we could, at our option and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such plants and forego such capital and/or operating costs.

Power generating facilities are a major source of GHG emissions – in 2009, our facilities in GEN-MW, GEN-WE and GEN-NE emitted approximately 22.1 million, 3.7 million and 5.8 million tons of CO_2, respectively. The amounts of CO_2 emitted from our facilities during any time period will depend upon their dispatch rates during the period.

Though we consider our largest risk related to climate change to be legislative and regulatory changes intended to slow or prevent it, we are subject to physical risks inherent in industrial operations including severe weather events such as hurricanes and tornadoes. To the extent that changes in climate effect changes in weather patterns (such as more severe weather events) or changes in sea level where we have generating facilities, we could be adversely affected. To the extent that climate change results in changes in sea level, we would expect such effects to be gradual and amenable to structural mitigation during the useful life of the facilities. However, if this is not the case it is possible that we would be impacted in an adverse way, potentially materially so. We could experience both risks and opportunities as a result of related physical impacts. For example, more extreme weather patterns – namely, a warmer summer or a cooler winter – could increase demand for our products. However, we also could experience more difficult operating conditions in that type of environment. We maintain various types of insurance in amounts we consider appropriate for risks associated with weather events.

Federal Legislation Regarding Greenhouse Gases. Several bills have been introduced in Congress since 2003 that if passed would compel reductions in CO_2 emissions from power plants, but only recently has a proposed bill received majority support in the U.S. House of Representatives or U.S. Senate. In June 2009, the House of Representatives passed the American Clean Energy and Security Act of 2009 ("H.R. 2454"). Title III of H.R. 2454 would add a new Title VII to the CAA creating a Global Warming Pollution Reduction Program. H.R. 2454 would also create a national cap-and-trade program aimed at reducing CO_2 emissions to three percent below 2005 levels by 2012, 17 percent below 2005 levels by 2020, 42 percent below 2005 levels by 2030 and 83 percent below 2005 levels by 2050.

Several bills have been introduced in the Senate; one bill similar to H.R. 2454, S. 1733, has been passed by the Senate Environment and Public Works Committee.

Federal Regulation of Greenhouse Gases. Recent court decisions and interpretations of the CAA by the 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*, a case involving the regulation of GHG emissions from new 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 EPA had a duty to determine whether or not GHG emissions from motor vehicles might reasonably be anticipated to endanger public health or welfare within the meaning of the CAA. In July 2008, the EPA issued an ANPR on Regulating Greenhouse Gas Emissions Under the Clean Air Act. The ANPR sought comment on a wide range of issues related to regulation of GHG under the present CAA. The then Administrator of the EPA expressed his opinion in the ANPR that the CAA was "ill-suited for the task of regulating" GHG.

With the change in administration following the 2008 Presidential election, many policies and interpretations of environmental laws and regulations by the former administration are being reevaluated. In response to the ruling in *Massachusetts v. EPA*, the new Administrator of the EPA issued a proposed finding in April 2009 that GHG emissions from motor vehicles cause or contribute to air pollution that endangers the public health and welfare. After a comment period, the new Administrator of the EPA issued a final endangerment finding under Section 202(a) of the CAA in December 2009. The decision found that six GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare. Subsequently, petitions for administrative reconsideration of EPA's endangerment finding were filed, and sixteen petitions for review of the final EPA action have been filed in the U.S. Court of Appeals for the District of Columbia by organizations representing industry, an organization representing nine members of Congress, and by the states of Alabama, Texas and Virginia.

In anticipation of its final endangerment finding, the EPA issued several proposed rules concerning GHGs in September 2009:

- The EPA and the U.S. Department of Transportation proposed a joint rule that would regulate GHG emissions from passenger cars and light trucks under Section 202(a) of the CAA. While this proposed rule will not directly affect us, if it becomes final it may render GHGs, including CO_2, "subject to regulation" under the CAA, potentially triggering the requirements of the PSD program including the requirement to implement BACT for control of CO_2 for new and modified stationary sources such as power plants.
- The EPA released its final rule requiring mandatory reporting of GHG emissions from all sectors of the economy. This rule requires that certain sources, including our power generating facilities, monitor and report GHG emissions. The rule went into effect in January 2010 and requires that reports of GHG emissions be filed annually thereafter. We have implemented new processes and procedures to report these emissions as required and intend to comply with this rule.
- The EPA proposed to "phase in" new GHG emissions applicability thresholds for its PSD permit program and for the operating permit program under Title V of the CAA. The proposed rule would establish a temporary GHG applicability threshold for these programs at 25,000 tons per year of CO_2e for new sources, and a temporary GHG significance level under the PSD Permit Program between 10,000 and 25,000 tons per year CO_2e for modifications to major sources. Public debate is ongoing as to the EPA's legal authority to adopt this rule, making legal challenges to the rule likely. We cannot predict with confidence the outcome of this rulemaking process or a specific impact on our generating portfolio.

State Regulation of Greenhouse Gases. Many states where we operate generation facilities have, are considering, or are in some stage of implementing, regulatory programs intended to reduce emissions of GHGs from stationary sources as a means of addressing climate change. Beginning in 2009, our generating facilities in New York and Maine were required to purchase CO_2 allowances, from the states where they operate, in sufficient quantities to cover CO_2 emissions. Please see "Northeast" below for further information. Beginning in 2012, our generating facilities in California are also expected to be required to purchase CO_2 allowances in sufficient quantities to cover CO_2 emissions. Please see "West" below for further information.

Midwest. Our assets in Illinois may become subject to a regional GHG cap and trade program being developed under the MGGA. The MGGA is an agreement among six states and the Province of Manitoba to create the 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 MGGRP is, however, still in an early stage of development and specific targets for GHG emission reductions and regulations to achieve such targets have not yet been agreed to by the members.

West. We currently expect that our assets in California will be subject to the California Global Warming Solutions Act ("AB 32"), which became effective in January 2007. AB 32 requires the CARB to develop a GHG emission control program that will reduce emissions of GHG in the state to their 1990 levels by 2020. Final regulations necessary to meet the 2020 GHG emissions cap are required by January 2011, and a fully effective regulatory program must be in place by January 2012. The CARB released preliminary draft regulations to meet the AB 32 mandate through a cap and trade program in November 2009. Initially, the program is expected to apply to large stationary sources including power generation facilities. GHG emission allowances are expected to be sold at auctions beginning in the fall of 2011. The details of the auction and other compliance rules will be outlined in draft rules expected to be released in Spring 2010.

The State of California is a party to a regional GHG cap and trade program being developed under the WCI to reduce GHG emissions in the participating states. The WCI is a collaborative effort among seven states and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. California's implementation of AB 32 is expected to constitute the state's contribution to the WCI and to form the model for other participating jurisdictions.

Northeast. On January 1, 2009, our assets in New York and Maine became subject to a state-driven GHG emission control program known as RGGI. RGGI was developed and implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states implemented rules regulating GHG emissions using a cap-and-trade program to reduce CO_2 emissions by at least 10 percent of 2009 emission levels by the year 2018. Compliance with the allowance requirement under the RGGI cap-and-trade program can be achieved by reducing emissions, purchasing or trading allowances, or securing offset allowances from an approved offset project. While allowances are sold by year, actual compliance is measured across a three year control period. The first control period is for the 2009-2011 timeframe.

In December 2009, RGGI held its sixth auction, in which approximately 28 million allowances for allocation year 2009, and 1.5 million allowances for allocation year 2012, were sold at clearing prices of $2.05 and $1.86 per allowance, respectively. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure some allowances for our affected assets. We expect that the increased operating costs resulting from purchase of CO_2 allowances will be at least partially reflected in market prices. The RGGI states plan to continue to conduct quarterly auctions in 2010 and 2011.

Our generating facilities in New York and Maine emitted approximately 5.8 million tons of CO_2 during 2009, this includes our Bridgeport facility which was sold in the LS Power Transactions. Based on the average clearing price of $2.91 for 2009 allowances sold in all auctions held to date, we estimate our cost of allowances required to operate these facilities during 2009 would be approximately $16.9 million. The RGGI compliance period is three years, so the actual cost of allowances required for our 2009 operations may vary from this estimate as a result of purchases and/or sales of allowances between now and 2012, which may result in a lower or higher average allowance cost.

Climate Change Litigation. There is a risk of litigation from those seeking injunctive relief from or to impose liability on sources of GHG emissions, including power generators, for claims of adverse effects due to climate change. Recent court decisions disagree on whether the claims are subject to resolution by the courts and whether the plaintiffs have standing to sue.

In September 2009, the U.S. Court of Appeals for the 2nd Circuit held that the U.S. District Court is an appropriate forum for resolving claims by eight states and New York City against six electric power generators related to climate change. Similarly, in October 2009, the U.S. Court of Appeals for the 5th Circuit held that claims related to climate change by property owners along the Mississippi Gulf Coast against energy companies could be resolved by the courts. However, in September 2009, the U.S. District Court for the Northern District of California dismissed claims related to climate change by an Alaskan community against 24 companies in the energy industry, including us, in *Native Village of Kivalina and City of Kivalina v. ExxonMobil Corporation, et al.* Please read Note 21—Commitments and Contingencies for further discussion of this case.

The conflict in recent court decisions illustrates the unsettled law related to claims based on the effects of climate change. Nevertheless, the decisions affirming the jurisdiction of the courts and the standing of the plaintiffs to bring these claims could result in an increase in similar lawsuits and associated expenditures by companies like ours.

Carbon Initiatives. We participate in several programs that partially offset or mitigate our GHG 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 hardwood 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. In Illinois, we are funding prairie, bottomland hardwood and savannah restoration projects in partnership with the Illinois Conservation Foundation. We also have programs to reuse CCB produced at our coal-fired generation units through agreements with cement manufacturers that incorporate the material into cement products, helping to reduce CO_2 emissions from the cement manufacturing process.

Our Moss Landing facility in California is involved in a pilot project with Calera Corporation that treats flue gas emissions from the facility in a process that produces materials similar to Portland cement and aggregate. The Calera carbonate mineralization process binds CO_2 with minerals in brines or seawater in a manner that has the potential to permanently sequester the CO_2 in the solid materials it produces. If this process can be developed on a commercial scale, it would provide a means of capturing CO_2 and creating beneficial, marketable products for the building materials industry.

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

Other Environmental Matters

Multi-Pollutant Air Emission Initiatives

In recent years, various federal and state legislative and regulatory multi-pollutant initiatives have been introduced. In early 2005, the EPA finalized several rules that would collectively require reductions of approximately 70 percent each in emissions of SO_2 and NO_x by 2015 and mercury by 2018 from coal-fired power generation units.

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 to address fine particulate matter and ground-level ozone National Ambient Air Quality Standards, was issued as a final rule in April 2006. CAIR was challenged and the U.S. Court of Appeals for the District of Columbia has remanded the rule to the EPA to correct several aspects of the rule determined by the Court to be unacceptable. The rule remains effective until the EPA completes its rulemaking to replace CAIR. Our facilities in Illinois and New York are subject to state SO_2 and NO_x limitations more stringent than those imposed by the currently effective CAIR. The EPA is expected to propose a new CAIR rule in the spring of 2010 and it is possible that this new rule will require greater emissions reductions, and therefore increased environmental expenditures, from power generating facilities like ours.

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 State of New York has initiated rulemaking to establish BART limits that may result in more stringent emission control requirements, and significant expenditures for environmental control equipment, for our Danskammer facility.

In March 2005, the EPA issued the CAMR for control of mercury emissions from coal-fired power plants 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. In February 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. In December 2009, the EPA issued information requests under Section 114 of the CAA to many coal and oil fired steam electric generating companies, including certain of our operating companies. These requests require stack tests to develop information on emissions of mercury and other HAPs and will be used by the EPA to develop emission standards for HAPs under Section 112 of the CAA.

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. When our plans are complete, our four coal-fired units at our Baldwin and Havana facilities will have dry flue gas desulphurization systems for the control of SO_2 emissions, and electrostatic precipitators and baghouses for the control of particulate emissions. Selective catalytic reduction technology for the control of NO_X emissions has been installed and operated on three of these units for several years; GEN-MW's remaining units use low-NO_X burners and overfire air to lower NO_X emissions. Our coal-fired units at our Vermillion and Hennepin facilities have electrostatic precipitators and baghouses for the control of particulate matter. We anticipate that we will have activated carbon injection technology for the control of mercury emissions installed and operating on 95 percent of GEN-MW's coal-fired capacity by mid-2010 and the final unit by 2013.

Midwest Consent Decree. In 2005, we settled a lawsuit filed by the EPA and the U.S. Department of Justice that alleged violations of the CAA and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating facility. A consent decree was finalized in July 2005 that would prohibit operation of certain of our power generating facilities after certain dates unless specified emission control equipment is installed (the "Midwest Consent Decree"). We have achieved all emission reductions to date under the Midwest Consent Decree and are in the process of installing additional emission control equipment to meet future Midwest Consent Decree emission limits. We anticipate our costs associated with the Midwest Consent Decree projects, which we expect to incur through 2013, will be approximately $960 million, which includes approximately $545 million spent to date. This estimate required a number of assumptions about uncertainties that are beyond our control, including an assumption 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 Midwest Consent Decree:

2010	2011	2012	2013
(in millions)			
$185	$140	$75	$15

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

Information Request under Section 114 of the Clean Air Act. In March 2009, we received an information request from the EPA regarding maintenance, repair and replacement projects undertaken between January 2000 and the present at the Danskammer facility. We submitted responses to the information request in April and July 2009 and are continuing to cooperate with the EPA to provide additional information as requested. The information request is related to a nationwide enforcement initiative by the EPA targeting electric utilities. The EPA's inquiry may lead to claims of CAA violations that could result in an enforcement action, the scope of which cannot be predicted with confidence at this time, but which could have a material adverse effect on our financial condition, results and cash flows.

The Clean Water Act

Our water withdrawals and wastewater discharges are permitted under the CWA and analogous state laws. The cooling water intake structures at several of our facilities are regulated under section 316(b) of the CWA. This provision generally directs that standards set for facilities require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact. These standards are developed and implemented for power generating facilities through NPDES permits or 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 EPA issued the Cooling Water Intake Structures Phase II Rules (the "Phase II Rules"), which set forth standards to implement the BTA requirements for cooling water intakes at existing facilities. The rules were challenged by several environmental groups and in 2007 were struck down by the U.S. Court of Appeals for the 2nd Circuit in *Riverkeeper, Inc. v. EPA.* The Court's decision remanded several provisions of the rules to the EPA for further rulemaking. Several parties sought review of the decision before the U.S. Supreme Court. In April 2009, the U.S. Supreme Court ruled that the EPA permissibly relied on cost-benefit analysis in setting the national BTA performance standard and in providing for cost-benefit variances from those standards as part of the Phase II Rules.

In July 2007, following remand of the rules by the U.S. Court of Appeals, the EPA suspended its Phase II Rules and advised that permit requirements for cooling water intake structures at existing facilities should once more be established on a case-by-case best professional judgment basis until replacement rules are issued. The scope of requirements, timing for compliance and the compliance methodologies that will ultimately be allowed by future rulemaking may become more restrictive, resulting in potentially significantly increased costs.

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

- Danskammer SPDES Permit – In January 2005, the NYSDEC issued a draft SPDES permit renewal for the Danskammer power generation facility. Three environmental groups sought to impose a permit requirement that the Danskammer facility install a closed cycle cooling system. Following a formal evidentiary hearing, the revised Danskammer SPDES permit was issued in June 2006 without requiring installation of a closed cycle cooling system. The permit was upheld on appeal by the Appellate Division and petitions for leave to appeal to the New York Court of Appeals were denied.
- Roseton SPDES Permit – In April 2005, the NYSDEC issued a draft SPDES permit renewal for the Roseton power generation facility. 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 facility 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. The adjudicatory hearing on the draft Roseton SPDES permit will be scheduled after the Commissioner rules on the appeal. We believe that the petitioners' claims lack merit and we plan to continue to oppose those claims vigorously.
- Moss Landing NPDES Permit – The California Regional Water Quality Control Board ("California Water Board") issued an NPDES permit for the Moss Landing power generation facility in 2000 in connection with modernization of the facility. A local environmental group sought review of the permit contending that the once through seawater-cooling system at the Moss Landing power generation facility should be replaced with a closed-cycle cooling system to meet the BTA requirements. Following an initial remand from the courts, the California Water Board affirmed its BTA finding. The California 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 California Supreme Court, which was granted in March 2008. The California Supreme Court deferred further action pending final disposition of the U.S. Supreme Court challenge regarding the Phase II Rules. The California Supreme Court has since directed the parties to brief all issues raised by the pleadings. The petitioner's brief was filed in December 2009 and our response is due in March 2010. We believe that petitioner's claims lack merit and we plan to continue opposing those claims vigorously.

Due to the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

- South Bay NPDES Permit – The California Regional Water Quality Control Board for the San Diego Region (the "San Diego Regional Water Board") recently granted an administrative extension of the South Bay facility's NPDES permit until December 31, 2010. Under the terms of the extension, operation of Units 3 and 4 was authorized through December 31, 2009. These units have ceased operation. The administrative extension authorized operation of Units 1 and 2 only through December 31, 2010, absent further action by the San Diego Regional Water Board. The San Diego Regional Water Board has scheduled a public hearing for March 2010 to receive evidence on the impacts of the South Bay intake and discharge.

In June 2009, the California Water Board issued its draft Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (the "Policy"). If the Policy becomes final in its present form, it will require that existing power plants either: (i) reduce their water intake flow rate to a level commensurate with that which can be achieved by a closed cycle wet cooling system; or (ii) reduce impingement mortality and entrainment to a level comparable to that achieved by such a reduced water intake flow rate using operational or structural controls, or both. The Policy may allow less stringent requirements under limited circumstances for very efficient generating units, such as Moss Landing's Units 1 and 2. Compliance with the Policy would be required at our South Bay power generation facility by December 2012, at our Morro Bay power generation facility by December 2015 and at our Moss Landing power generation facility by December 2017. A public hearing was held on the policy in September 2009 and public comments were taken through the end of September 2009. We filed substantial comments on the draft policy.

Given the numerous variables and factors involved in calculating the potential costs associated with closed cycle cooling, any decision to install such a system at any of our facilities, should they be required, 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 such facility and forego these capital expenditures.

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

Coal Combustion Byproducts

The combustion of coal to generate electric power creates large quantities of ash that are managed at power generation facilities in dry form in landfills and in liquid or slurry form in surface impoundments. Each of our coal-fired plants has at least one CCB management unit. At present, CCB management is regulated by the states as solid waste. The EPA has considered whether CCB should be regulated as a hazardous waste on two separate occasions, including most recently in 2000, and both times has declined to do so. The December 2008 failure of a CCB surface impoundment dike at the Tennessee Valley Authority's Kingston Plant in Tennessee accompanied by a very large release of ash slurry has resulted in renewed scrutiny of CCB management.

In response to the Kingston ash slurry release, the EPA initiated an investigation of the structural integrity of certain CCB surface impoundment dams including those at our GEN-MW facilities. Our surface impoundment dams were found to be in satisfactory condition, the highest rating. Additionally, the EPA announced plans to develop regulations regarding the handling and disposal of CCB by the end of 2009 to address the management of CCB; while no proposed rule has been released to date, a proposed rule is expected to be released in the first quarter 2010.

Certain environmental organizations have advocated designation of CCB as a hazardous waste; however, many state environmental agencies have expressed strong opposition to such designation. The regulations being developed by the EPA could lead to new requirements related to CCB management units. The nature and scope of these requirements cannot be predicted with confidence at this time, but could have a material adverse effect on our financial condition, results of operations and cash flows. Further, public perception or new regulations regarding the reuse of coal ash may limit or eliminate the market that currently exists for coal ash reuse, which could have material adverse affects on our financial condition, results of operations and cash flows.

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 contaminated sites resulting from the release of "hazardous substances" 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 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.

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.

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 renewable-fueled power generation facilities. For example, regulatory requirements for load-serving entities to acquire a percentage of their energy from renewable-fueled facilities will potentially reduce the demand for energy from coal-fired facilities such as those we own and operate. We believe our primary competitors consist of at least 20 companies in the power generation business.

SIGNIFICANT CUSTOMERS

For the year ended December 31, 2009, approximately 19 percent, 12 percent and 11 percent of our consolidated revenues were derived from transactions with MISO, NYISO and PJM, respectively. 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. No other customer accounted for more than 10 percent of our consolidated revenues during 2009, 2008 or 2007.

EMPLOYEES

At December 31, 2009, we had approximately 472 employees at our corporate headquarters and approximately 1,263 employees at our facilities, including field-based administrative employees. Approximately 763 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions that expire in August 2010, June 2011 and January 2013. 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:

- the timing and anticipated benefits to be achieved through our 2010-2013 company-wide cost savings program;
- beliefs and assumptions relating to liquidity, available borrowing capacity and capital resources generally;
- expectations regarding environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts, and other laws and regulations to which we are, or could become, subject;
- beliefs about commodity pricing and generation volumes;
- anticipated liquidity in the regional power and fuel markets in which we transact, including the extent to which such liquidity could be affected by poor economic and financial market conditions or new regulations and any resulting impacts on financial institutions and other current and potential counterparties;
- sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation thereof;
- beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale power generation market, including the anticipation of a market recovery over the longer term;
- the effectiveness of our 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;
- beliefs regarding the current economic downturn, its trajectory and its impacts;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- beliefs and expectations regarding financing and associated credit ratings, development and timing and disposition of the Plum Point Project;
- expectations regarding our revolver capacity, credit facility compliance, collateral demands, 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; and

- expectations and estimates regarding capital and maintenance expenditures, including the Midwest Consent Decree and its associated costs.

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

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 include:

- the 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) or the functioning of the energy trading markets and energy trading generally;
- fuel price volatility; and
- increased competition or price pressure driven by generation from renewable sources.

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.

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 predictability of earnings and cash flows in the short- and medium-term with a belief that commodity prices will rise over the longer term, creating upside opportunities for those with unhedged generation volumes. 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 reliability of the people and systems comprising our commercial operations function. The availability of market liquidity and willing counterparties could be negatively impacted by continued poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties. If we are unable to transact in the short- and medium-term, our financial condition, results of operations and cash flows will be subject to significant uncertainty and volatility. Alternatively, significant contract execution for this period may precede a run-up in commodity prices, resulting in lost upside opportunities and mark-to-market accounting losses causing 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, primarily 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, profitable operation of many of our coal-fired generation facilities is highly dependent on our ability to procure coal at prices we consider reasonable. Power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. In the Midwest, a majority of our coal supply is not contracted beyond 2010. Additionally, our Midwest coal transportation agreement expires in 2013, and we expect any revision or extension to result in higher coal transportation costs. We have entered into term contracts for South American coal, which we use for our GEN-NE coal facility, and for PRB, which we use for our GEN-MW coal facilities. We cannot assure you that we will be able to renew our coal procurement and transportation contracts when they terminate on terms that are favorable to us or at all. Further, our and our suppliers' ability to procure 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 that restrict the sulfur content of coal used at our coal facilities limit our options for coal fuel supply, creating 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 and changes in the relationship between such costs and the market prices of power will affect our financial results. 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 or factors could materially 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 GHG) 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 regulation of GHGs) could, if and when adopted or enacted, require us to make substantial capital and operating expenditures or consider retiring certain of our facilities. If any of these events occur, our financial condition, results of operations and cash flows could be materially adversely affected.

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 for us to continue operating our facilities. The process of 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, changed interpretations of existing regulations may subject 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.

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; increased credit standards, collateral costs or margin requirements, as well as reduced market liquidity, as a result of potential OTC market regulation; 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 and the trend toward more stringent regulations (including regulations regarding GHG 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 the age of certain of our generation facilities and 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, other energy service companies and financial institutions 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 these plants at a competitive disadvantage. Over time, some of our plants may become unable to compete, because of the construction of new plants which could have a number of advantages including; more efficient equipment, newer technology that could result in fewer emissions, or more advantageous locations on the electric transmission system. Additionally, these competitors may be able to respond more quickly to new laws and regulations because of the newer technology utilized in their facilities or the additional resources derived from owning more efficient facilities. Taken as a whole, the potential disadvantages of our aging fleet could result in lower run-times or even early asset retirement.

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. 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 2013. Additionally, unionization activities, including votes for union certification, could occur at our non-union 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 Midwest Consent Decree may be materially adversely impacted by unforeseen labor, material and equipment costs.

As a result of the Midwest 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 Midwest Consent Decree and anticipate incurring additional significant costs over the course of the next three years. We are exposed to the risk of substantial price increases in the costs of materials, labor and equipment used in the construction of emission control equipment. We are further exposed to risk in that counterparties to the construction contracts 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 Midwest 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 respective 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, 2009, the termination payment would be approximately $853 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, 2009, we had total consolidated debt of approximately $5.6 billion. Our significant level of debt could:

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

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 (the "Credit Facility"), 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 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 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 reduced borrowing capacity or even 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.

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 changes in our credit rating or liquidity and changes in commodity prices for power and fuel, among others.

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

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.

If Dynegy issues or acquires a material amount of its common stock in the future or certain of its stockholders sell a material amount of Dynegy's common stock, Dynegy's ability to use its federal net operating losses or alternative minimum tax credits to offset its future taxable income may be limited under Sections 382 and 383 of the Internal Revenue Code.

Dynegy's ability to utilize previously incurred federal NOLs and alternative minimum tax (AMT) credits to offset future taxable income would be limited if it were to undergo an "ownership change" within the meaning of Section 382 of the Internal Revenue Code (the "Code"). In general, an ownership change occurs whenever the percentage of the stock of a corporation owned by "5-percent shareholders" (within the meaning of Section 382 of the Code) increases by more than 50 percentage points over the lowest percentage of the stock of such corporation owned by such "5-percent shareholders" at any time over the preceding three years. Under certain circumstances, issuances or acquisitions of our own common stock or sales or dispositions of our common stock by stockholders could trigger an "ownership change," and we will have limited control over the timing of any such sales or dispositions of our common stock. Any such future ownership change could result in limitations, pursuant to Sections 382 and 383 of the Code, on Dynegy's utilization of federal NOLs and AMT credits to offset our future taxable income.

More specifically, depending on prevailing interest rates and our market value at the time of such future ownership change, an ownership change under Section 382 of the Code would establish an annual limitation which might prevent full utilization of the deferred tax assets attributable to our previously incurred federal NOLs and AMT credits against the total future taxable income of a given year. The LS Power Transactions and other recent stockholder activity increase the likelihood that previously incurred federal NOLs and AMT credits will become subject to the limitations set forth in Sections 382 and 383 of the Code. If such an ownership change were to occur, our ability to raise additional equity capital may be limited.

The magnitude of such limitations and their effect on us are difficult to assess and depend in part on our value at the time of any such ownership change and prevailing interest rates. For accounting purposes, at December 31, 2009, Dynegy's net operating loss deferred tax asset attributable to its previously incurred federal NOLs was approximately $125 million and its AMT credits were approximately $272 million.

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 Credit Facility. Please read Note 17—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, Pennsylvania and Texas.

Item 3. ***Legal Proceedings***

Please read Note 21—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 2009.

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 19, 2010, based upon records of registered holders maintained by its transfer agent, was 18,883.

All of the shares of Class B common stock that were previously owned by the LS Power were cancelled as of November 30, 2009.

The following table sets forth the high and low closing sales prices for Dynegy's Class A common stock for each full quarterly period during the fiscal years ended December 31, 2009 and 2008 and during the elapsed portion of Dynegy's first fiscal quarter of 2010 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
2010:		
First Quarter (through February 19, 2010)	$ 1.99	$ 1.57
2009:		
Fourth Quarter	$ 2.63	$ 1.81
Third Quarter	2.55	1.78
Second Quarter	2.47	1.45
First Quarter	2.69	1.04
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

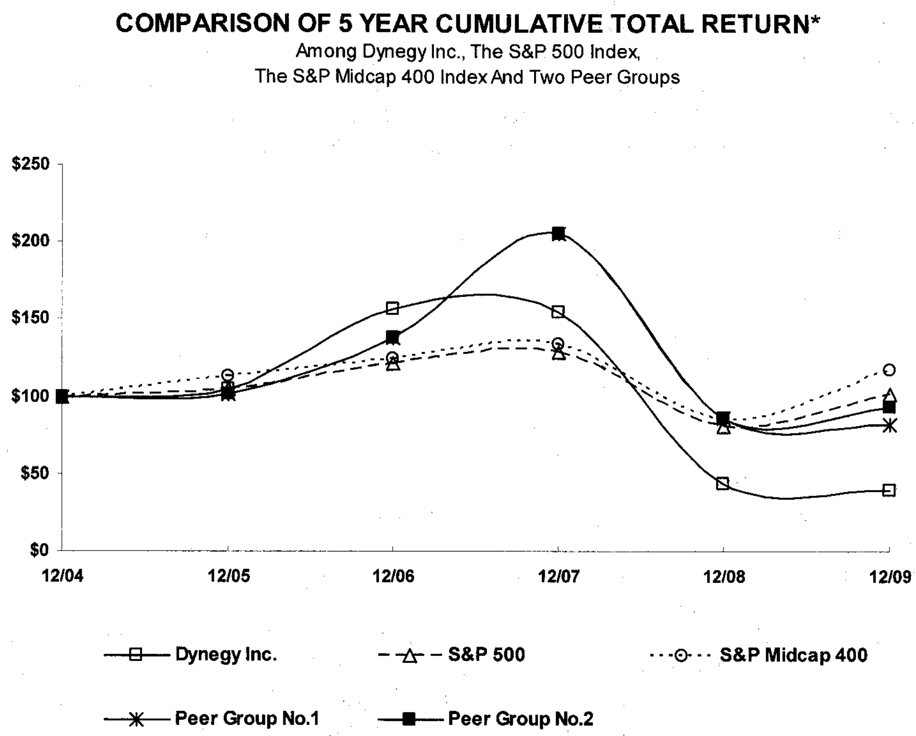
During the fiscal years ended December 31, 2009 and 2008, Dynegy's Board of Directors did not elect to pay a common stock dividend. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Dividends on Dynegy Common Stock" 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 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 22—Capital Stock—Common Stock for further discussion.

Shareholder Agreements. Dynegy entered into a shareholder agreement dated as of September 14, 2006 (the "Old 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. (collectively, "LS Power") that imposed upon LS Power certain restrictions and limitations but also provided them with special approval rights, board representation and certain other rights.

On November 30, 2009, as part of the LS Transactions, Dynegy and LS Power terminated the Old Shareholder Agreement and entered into a second shareholder agreement (the "New Shareholder Agreement") which, among other things, generally restricts LS Power from increasing its now-reduced ownership for a specified period up to 30 months. Additionally, it provides that we will not issue Dynegy's equity securities for our own purposes until the earlier of (i) March 31, 2010 or (ii) the first date following closing of the transaction in which LS Power owns, in aggregate, less than 10 percent of Dynegy's then outstanding Class A common stock. The New Shareholder Agreement does not, however, include any of the special rights (such as Board rights, special approval rights or preemption rights) previously associated with LS Power's ownership. However, the LS Registration Rights Agreement as amended remains in effect.

Amended LS Registration Rights Agreement. In conjunction with the signing of the Old Shareholder Agreement, Dynegy also entered into a Registration Rights Agreement with LS Power on September 14, 2006 (the "Registration Rights Agreement"). This Registration Rights Agreement required Dynegy 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 shares of Class B common stock owned by LS Power. This "shelf" registration statement was filed with the SEC on April 5, 2007. On August 9, 2009 the Registration Rights Agreement was amended (the "Amended Registration Rights Agreement"). The Amended Registration Rights Agreement provides, in part, that Dynegy will be obligated to undertake up to two underwritten offerings for the benefit of LS Power in each twelve-month period, provided that the aggregate proceeds to be received by LS Power under any such offering must not be less than the lesser of $100 million and the then-current market value of 40 million shares of Dynegy's common stock. Dynegy will be able to defer an underwritten offering by LS Power if Dynegy is conducting or about to conduct an underwritten offering of common stock for its own account with aggregate proceeds in excess of $100 million. However, Dynegy will not be permitted to exercise its right to defer an underwritten offering by LS Power during the period ending on the earlier of (i) March 31, 2010 and (ii) the first date on which LS power owns, in aggregate, less than 10 percent of all of Dynegy's Class A common stock, and thereafter Dynegy's deferral right can only be exercised once per calendar year. The Amended Registration Rights Agreement also provides certain "piggyback" rights for LS Power in connection with future equity offerings Dynegy might conduct, subject to customary underwriter limitations.

Stockholder Return Performance Presentation. The graph below compares the cumulative 5-year total return of holders of Dynegy Inc.'s common stock with the cumulative total returns of the S&P 500 index, the S&P Midcap 400 index, and two customized peer groups of companies. The first peer group ("Peer Group No. 1") includes: Mirant Corp., NRG Energy Inc. and RRI Energy Inc.; and the second group ("Peer Group No. 2") includes: Calpine Corp., Mirant Corp., NRG Energy Inc. and RRI Energy Inc. In 2008, Dynegy was included in the S&P 500 and did not include Calpine Corp. in its peer group because Calpine Corp. was still emerging from bankruptcy. In 2009, Dynegy moved into the S&P Midcap 400 and included Calpine Corp. in its peer group. The graph tracks the performance of a $100 investment in our common stock, in each of the peer groups, and the two indices (with the reinvestment of all dividends) from 12/31/2004 to 12/31/2009.



*$100 invested on 12/31/04 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	12/04	12/05	12/06	12/07	12/08	12/09
Dynegy Inc.	100.00	104.76	156.71	154.55	43.29	39.18
S&P 500	100.00	104.91	121.48	128.16	80.74	102.11
S&P Midcap 400	100.00	112.55	124.17	134.08	85.50	117.46
Peer Group No.1	100.00	101.46	138.14	205.18	86.58	82.26
Peer Group No.2	100.00	101.46	138.14	205.18	86.58	93.46

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 1 to October 31, 2009	8,567	$ 2.50	—	N/A
November 1 to November 30, 2009	728	$ 1.93	—	N/A
December 1 to December 31, 2009	1,712	$ 1.88	—	N/A
Total	11,007	$ 2.37	—	N/A

These were the only repurchases of equity securities made by Dynegy during the three months ended December 31, 2009. 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,				
	2009	2008	2007	2006	2005
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$ 2,468	$ 3,324	$ 2,918	$ 1,758	$ 2,004
Depreciation and amortization expense	(335)	(346)	(306)	(208)	(199)
Goodwill impairment	(433)	—	—	—	—
Impairment and other charges, exclusive of goodwill impairment shown separately above	(538)	—	—	(9)	(46)
General and administrative expenses	(159)	(157)	(203)	(196)	(468)
Operating income (loss)	(834)	744	576	220	(826)
Interest expense and debt extinguishment costs (2)	(461)	(427)	(384)	(631)	(389)
Income tax (expense) benefit	315	(90)	(140)	116	391
Income (loss) from continuing operations	(1,040)	188	105	(242)	(796)
Income (loss) from discontinued operations (3)	(222)	(17)	166	(92)	891
Cumulative effect of change in accounting principles	—	—	—	1	(5)
Net income (loss)	$ (1,262)	$ 171	$ 271	$ (333)	$ 90
Net income (loss) attributable to Dynegy Inc. common stockholders	(1,247)	174	264	(342)	68
Basic earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders	$ (1.25)	$ 0.23	$ 0.13	$ (0.55)	$ (2.11)
Basic net income (loss) per share attributable to Dynegy Inc. common stockholders	(1.52)	0.20	0.35	(0.75)	0.18
Diluted earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders	$ (1.25)	$ 0.23	$ 0.13	$ (0.55)	$ (2.11)
Diluted net income (loss) per share attributable to Dynegy Inc. common stockholders	(1.52)	0.20	0.35	(0.75)	0.18
Shares outstanding for basic EPS calculation	822	840	752	459	387
Shares outstanding for diluted EPS calculation	826	842	754	509	513
Cash dividends per common share	$ —	$ —	$ —	$ —	$ —
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ 135	$ 319	$ 341	$ (194)	$ (30)
Net cash provided by (used in) investing activities	251	(102)	(817)	358	1,824
Net cash provided by (used in) financing activities	(608)	148	433	(1,342)	(873)
Cash dividends or distributions to partners, net	—	—	—	(17)	(22)
Capital expenditures, acquisitions and investments	(594)	(640)	(504)	(163)	(315)

	December 31,				
	2009	2008	2007	2006	2005
			(in millions)		
Balance Sheet Data (4):					
Current assets	$ 2,038	$ 2,803	$ 1,663	$ 1,989	$ 3,706
Current liabilities	1,847	1,702	999	1,166	2,116
Property and equipment, net	7,117	8,934	9,017	4,951	5,323
Total assets	10,953	14,213	13,221	7,537	10,126
Long-term debt (excluding current portion)	4,775	6,072	5,939	3,190	4,228
Notes payable and current portion of long-term debt	807	64	51	68	71
Series C convertible preferred stock	—	—	—	—	400
Capital leases not already included in long-term debt	4	4	5	6	—
Total equity	2,979	4,485	4,529	2,267	2,140

(1) The LS Power 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) Includes $249 million of debt conversion costs for the twelve months ended December 31, 2006.

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

- The Arlington Valley and Griffith power generation facilities (collectively, the Arizona power generation facilities") (sold fourth quarter 2009);
- Bluegrass power generating facility (sold fourth quarter 2009);
- Heard County power generating facility (sold second quarter 2009);
- Calcasieu power generating facility (sold first quarter 2008);
- CoGen Lyondell power generating facility (sold third quarter 2007); and
- DMSLP (sold fourth quarter 2005).

(4) The LS Power Merger (April 2, 2007) and the Sithe Energies acquisition (February 1, 2005) 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.

Dynegy Holdings' Selected Financial Data

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$ 2,468	$ 3,324	$ 2,918	$ 1,758	$ 2,004
Depreciation and amortization expense	(335)	(346)	(306)	(208)	(199)
Goodwill impairment	(433)	—	—	—	—
Impairment and other charges, exclusive of goodwill impairment shown separately above	(538)	—	—	(9)	(40)
General and administrative expenses	(159)	(157)	(184)	(193)	(375)
Operating income (loss)	(836)	744	595	223	(727)
Interest expense and debt extinguishment costs (2)	(461)	(427)	(384)	(579)	(383)
Income tax (expense) benefit	313	(138)	(105)	89	372
Income (loss) from continuing operations	(1,046)	222	165	(217)	(723)
Income (loss) from discontinued operations (3)	(222)	(17)	166	(91)	809
Cumulative effect of change in accounting principles	—	—	—	—	(5)
Net income (loss)	$ (1,268)	$ 205	$ 331	$ (308)	$ 81
Net income (loss) attributable to Dynegy Holdings Inc.	$ (1,253)	$ 208	$ 324	$ (308)	$ 81
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ 152	$ 319	$ 368	$ (205)	$ (24)
Net cash provided by (used in) investing activities	790	(87)	(688)	357	1,839
Net cash provided by (used in) financing activities	(1,193)	146	369	(1,235)	(734)
Capital expenditures, acquisitions and investments	(596)	(626)	(350)	(155)	(169)

	December 31,				
	2009	2008	2007	2006	2005
	(in millions)				
Balance Sheet Data (1):					
Current assets	$ 1,988	$ 2,780	$ 1,614	$ 1,828	$ 3,457
Current liabilities	1,848	1,681	999	1,165	2,212
Property and equipment, net	7,117	8,934	9,017	4,951	5,323
Total assets	10,903	14,174	13,107	8,136	10,580
Long-term debt (excluding current portion)	4,775	6,072	5,939	3,190	4,003
Notes payable and current portion of long-term debt	807	64	51	68	191
Capital leases not already included in long-term debt	4	4	5	6	—
Total equity	3,003	4,583	4,620	3,036	3,331

(1) The Contributed Entities' (as defined in Note 3) assets were contributed to DHI contemporaneously with the LS Power Merger (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. 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) Includes $204 million of debt conversion costs for the twelve months ended December 31, 2006.

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

- The Arizona power generation facilities (sold fourth quarter 2009);

- Bluegrass power generating facility (sold fourth quarter 2009);
- Heard County power generating facility (sold second quarter 2009);
- Calcasieu power generating facility (sold first quarter 2008);
- CoGen Lyondell power generating facility (sold third quarter 2007); and
- DMSLP (sold fourth quarter 2005).

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 and how we allocate our resources, we report the results of each business as a separate segment in our consolidated financial statements. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization. Our 50 percent investment in SCH, which was sold in the fourth quarter 2009, is included in GEN-WE for reporting purposes. Dynegy's 50 percent investment in DLS Power Development, which was dissolved in the first quarter 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 Holding which is included in GEN-MW. PPEA Holding, through its wholly owned subsidiary, PPEA, owns an approximate 57 percent undivided interest in the Plum Point Project.

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 2009 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. Conversely, the recessionary economic environment has negatively impacted 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 coal, commonly referred to as the "spark spread" and "dark spread", respectively, which impacts the margin we earn on the electricity we generate; and

- Our ability to enter into commercial transactions to mitigate short- and medium- term earnings volatility and our ability to 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 operating expenses through disciplined management;
- Our ability to optimize our assets by maintaining a high in-market availability, reliable run-time and safe, low-cost operations;
- The cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive. Please see Business—Environmental Matters for further discussion; and
- Market supply conditions resulting from federal and regional renewable power initiatives.

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 GEN-MW include coal-fired facilities and natural gas-fired facilities. 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 to utilize a significant amount of cash for capital expenditures required to comply with the Midwest Consent Decree;
- Regional renewable energy mandates and initiatives that may alter supply conditions within the ISO and our generating units' positions in the aggregate supply stack;
- 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 GEN-WE are all natural gas-fired power generating facilities with the exception of our fuel oil-fired Oakland facility. The following specific factors impact or could impact the performance of this reportable segment:

- The continued need for reliability must-run services from the Oakland and South Bay facilities;
- The results of the South Bay facility's RMR rate negotiations, in which we intend to collect additional funds equal to the cost of the plant closure less the demolition and remediation costs collected in prior year's rates;
- Our ability to maintain and operate our plants in a manner that ensures we receive full capacity payments under our various tolling agreements; and

- Our ability to maintain the necessary permits to continue to operate our Moss Landing, Morro Bay and South Bay facilities with once-through, seawater cooling systems.

Power Generation—Northeast Segment. Our assets in GEN-NE 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;
- State-driven programs aimed at capping mercury and/or reducing emission levels of other constituents such as CO_2, NOx and SO_2 will impose additional costs on our power generation facilities;
- Changes in NYISO/ISO-NE market rules or state-specific mandates that favor and/or subsidize renewable energy sources and demand response initiatives; and
- Our ability to preserve and/or capture value around planned transmission upgrades designed to improve transfer limits around known constraints.

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 interest rate of approximately seven 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; (iii) any future corporate-level litigation reserves or settlements and (iv) our ability to realize the planned cost savings reflected in our 2010-2013 cost savings program; and
- Income taxes, which will be impacted by our ability to realize our net operating losses and alternative minimum tax credits.

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

2009 Highlights

LS Power Transactions. We consummated our transactions (the "LS Power Transactions") with LS Power in two parts, with the issuance of notes by DHI on December 1, 2009, and the remainder of the transactions closing on November 30, 2009. At closing, Dynegy received: (i) $936 million in cash, net of closing costs (consisting, in part, of (a) the release of $175 million of restricted cash on our consolidated balance sheets that was used to support our funding commitment to the Sandy Creek Project and (b) $214 million for the notes issued by DHI), and (ii) 245 million shares of Dynegy's Class B common stock from LS Power. In exchange, Dynegy sold to LS Power five peaking and three combined-cycle generation assets, as well as its remaining interest in the Sandy Creek Project under construction in Texas (the "Sandy Creek Project"), and DHI issued the notes to an affiliate of LS Power.

The remaining 95 million shares of Dynegy's Class B common stock held by LS Power were converted into the same number of shares of Dynegy's Class A common stock, representing approximately 15 percent of Dynegy's Class A common stock outstanding.

In connection with the LS Power Transactions, Dynegy and LS Power entered into the New Shareholder Agreement, which, among other things, generally restricts LS Power from increasing its now-reduced ownership for up to 30 months. Additionally, it provides that we will not issue Dynegy's equity securities for our own purposes until the earlier of (i) March 31, 2010 or (ii) the first date following closing of the transaction in which LS Power owns, in aggregate, less than 10 percent of Dynegy's then outstanding Class A common stock. Dynegy and LS Power have also terminated the Old Shareholder Agreement, which provided LS Power with special approval rights, board representation and certain other rights associated with its former Class B common stock. Please read Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Shareholder Agreements for further discussion.

In connection with our closing of the LS Power Transactions, we recorded pre-tax charges of $312 million in the fourth quarter 2009. These charges include $124 million in Gain (loss) on sale of assets, $104 million in Income (loss) from discontinued operations and $84 million in Losses from unconsolidated investments in our consolidated statements of operations. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion.

We also recorded pre-tax impairment charges of $579 million as a result of the negotiations leading up to and entering into the LS Power Transactions. Please read Note 6—Impairment Charges—2009 Impairment Charges—Assets Included in LS Power Transactions for further discussion.

Credit Facility Amendment. On August 5, 2009, we entered into certain amendments to the Credit Facility. Please read Note 17—Debt—Credit Facility for further discussion.

Multi-Year Cost Savings Initiative. On August 10, 2009, we announced an extensive, multi-year program to eliminate certain costs throughout the company. Cumulative savings, relative to our original plan, are expected to be $400 million to $450 million over a four-year period beginning in 2010. Annual savings are expected to be generated through reduced capital, operational and general and administrative expenditures.

Note Repurchase Agreement. On December 31, 2009, DHI completed a note repurchase with one of its larger fixed-income investors. DHI repurchased approximately $833 million aggregate principal amount of its notes, consisting of approximately $421 million of its 6.875% Senior Unsecured Notes due 2011 and approximately $412 million of its 8.750% Senior Unsecured Notes due 2012. The total consideration to effect the note repurchase, inclusive of consent fees, was $879 million. We recorded a charge of $46 million on the extinguishment of this debt.

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), and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated margin and collateral requirements, facility maintenance costs and other costs such as payroll.

Our primary sources of internal liquidity are cash flows from operations, cash on hand, and available capacity under our Credit Facility, 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. Secondarily, we expect to continue utilizing both lien-secured commodity hedging arrangements, which reduce collateral requirements, and commodity-contingent liquidity facilities, which increase potential liquidity availability. Additionally, DHI may borrow money from time to time from Dynegy. These internal liquidity sources are expected to be sufficient to fund the operation of our business, potential requirements to post additional collateral, as well as our planned capital expenditure program, including expenditures in connection with the Midwest Consent Decree, and debt service requirements over the next twelve months. Please read Note 17—Debt—Credit Facility for a discussion of the financial covenants contained in the Credit Facility, as well as the discussion below regarding our Revolver Capacity.

Our primary sources of external liquidity are asset sales proceeds and proceeds from capital market transactions to the extent we engage in these transactions.

Current Liquidity. The following table summarizes our consolidated revolver capacity and liquidity position at February 19, 2010, December 31, 2009 and December 31, 2008:

	February 19, 2010	December 31, 2009	December 31, 2008
		(in millions)	
Revolver capacity (1)	$ 1,080	$ 1,080	$ 1,080
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 (2)	102	102	377
Outstanding letters of credit (2)	(500)	(536)	(1,135)
Unused capacity	1,507	1,471	1,147
Cash—DHI	693	419	670
Total available liquidity—DHI	2,200	1,890	1,817
Cash—Dynegy	53	52	23
Total available liquidity—Dynegy	$ 2,253	$ 1,942	$ 1,840

(1) We currently have a syndicate of lenders participating in the revolving portion of our Credit Facility with commitments ranging from $10 million to $165 million.

(2) Reflects reduction of $275 million of capacity as of December 31, 2009 related to our investment in the Sandy Creek Project. At the close of the LS Power Transactions, this capacity was eliminated, and $175 million of the $275 million of restricted cash supporting this letter of credit capacity was released to us. See Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—LS Power Transactions for further discussion.

Cash on Hand. At February 19, 2010 and December 31, 2009, Dynegy had cash on hand of $746 million and $471 million, respectively, as compared to $693 million at the end of 2008. The increase in cash on hand at February 19, 2010 compared with December 31, 2009 is primarily related to return of cash from our broker margin account as a result of commodity price changes. The decrease in cash on hand at December 31, 2009 as compared to the end of 2008 is primarily attributable to cash used for debt repayments and capital expenditures partially offset by proceeds from the LS Power Transactions and the sale of Heard County as well as cash generated from the operating activities of our generation business.

At February 19, 2010 and December 31, 2009, DHI had cash on hand of $693 million and $419 million, respectively, as compared to $670 million at the end of 2008. The increase in cash on hand at February 19, 2010 compared with December 31, 2009 is primarily related to return of cash from our broker margin account as a result of commodity price changes. The decrease in cash on hand at December 31, 2009 as compared to the end of 2008 is primarily attributable to cash used for debt repayments, dividends to affiliates and capital expenditures partially offset by proceeds from the LS Power Transactions and the sale of Heard County as well as cash generated from the operating activities of our generation business.

Revolver Capacity. Based on management's current 2010 forecast, DHI's available liquidity under the Credit Facility will likely be reduced during 2010 as a result of the application of the covenant regarding the ratio of secured debt to adjusted EBITDA (as defined therein). The effect of reduced availability under the Credit Facility would be less available liquidity to DHI. However, even assuming such a reduction, we believe we have sufficient liquidity and capital resources to support our operations for the next twelve months. Please read Note 17—Debt—Credit Facility for further discussion of our Credit Facility.

Operating Activities

Historical Operating Cash Flows. Dynegy's cash flow provided by operations totaled $135 million for the twelve months ended December 31, 2009. DHI's cash flow provided by operations totaled $152 million for the twelve months ended December 31, 2009. During the period, our power generation business provided positive cash flow from operations of $719 million. Cash provided by the operations of our power generation facilities was partly offset by a $173 million increase in cash collateral postings. Other included a use of cash of approximately $584 million and $567 million by Dynegy and DHI, respectively, primarily due to interest payments to service debt and general and administrative expenses. Dynegy's operating cash flow also reflected the payment of $19 million to LS Power in conjunction with the dissolution of DLS Power Holdings and DLS Power Development.

Dynegy's and 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 the operations of our power generation facilities of $869 million, 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. Please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations— Liquidity and Capital Resources—Off-Balance Sheet Arrangements—DNE Leveraged Lease for further discussion of the DNE lease payments. Other included a use of approximately $550 million in cash 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. Other 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.

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, collateral requirements, the value of capacity and ancillary services, the run time of our generating facilities, the effectiveness of our commercial strategy, legal, environmental and regulatory requirements, our ability to execute the cost savings contemplated in the 2010-2013 cost savings program and our ability to capture value associated with commodity price volatility.

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 19, 2010, December 31, 2009 and December 31, 2008:

	February 19, 2010	December 31, 2009	December 31, 2008
		(in millions)	
By Business:			
Generation business	$ 515	$ 638	$ 1,064
Other	189	189	189
Total	$ 704	$ 827	$ 1,253
By Type:			
Cash (1)	$ 204	$ 291	$ 118
Letters of credit	500	536	1,135
Total	$ 704	$ 827	$ 1,253

(1) Includes Broker margin account on our consolidated balance sheets as well as other collateral postings included in Prepayments and other current assets on our consolidated balance sheets.

The changes in letters of credit postings from December 31, 2008 to December 31, 2009 and to February 19, 2010 are primarily related to a reduction of $275 million of capacity related to our former investment in the Sandy Creek Project and lower commodity prices. The decreases were partially offset by an increase in cash collateral postings largely due to an increased volume of transactions executed through our futures clearing manager.

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.

Investing Activities

Capital Expenditures. We continue to tightly manage our operating costs and capital expenditures. Our capital spending by reportable segment during 2009, 2008 and 2007 was as follows:

	December 31,		
	2009	2008	2007
		(in millions)	
GEN-MW	$ 533	$ 530	$ 300
GEN-WE	45	29	17
GEN-NE	28	36	47
Other	6	16	15
Total	$ 612	$ 611	$ 379

Capital spending in our GEN-MW segment primarily consisted of environmental and maintenance capital projects, as well as approximately $104 million, $203 million and $161 million spent on development capital related to the Plum Point Project during the years ended December 31, 2009, 2008 and 2007, respectively. Capital spending in our GEN-WE and GEN-NE segments primarily consisted of maintenance projects.

We expect capital expenditures for 2010 to approximate $435 million, which is comprised of $410 million, $5 million, $10 million and $10 million in GEN-MW, GEN-WE, GEN-NE and other, respectively. The $410 million of spending planned for GEN-MW includes approximately $200 million of environmental expenditures, of which approximately $185 million is related to the Midwest Consent Decree, approximately $95 million is related to maintenance on our coal and natural gas facilities, approximately $90 million is related to the Plum Point Project and approximately $25 million is related to capitalized interest. The capital expenditures related to the Plum Point Project will be largely funded by non-recourse project debt. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion. Other spending primarily includes maintenance capital projects and environmental projects. The capital budget is subject to revision as opportunities arise or circumstances change.

The Midwest Consent Decree was finalized in July 2005. It prohibits us from operating certain of our power generating facilities after certain dates unless specified emission control equipment is installed. Our long-term capital expenditures in the GEN-MW segment will be significantly impacted by the Midwest Consent Decree. We anticipate our costs associated with the Midwest Consent Decree projects, which we expect to incur through 2013, to be approximately $960 million, which includes approximately $545 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 remaining capital expenditures required to comply with the Midwest Consent Decree:

2010	2011	2012	2013
(in millions)			
$185	$140	$75	$15

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 Midwest Consent Decree. Please read Note 21—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, water 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 21—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 2009 totaled $652 million and $1,095 million for Dynegy and DHI, respectively. Of the total $936 million and $1,476 million in cash proceeds received by Dynegy and DHI, respectively, at the closing of the LS Power Transactions, $547 million and $990 million related to the disposition of assets, including our interest in the Sandy Creek Project, for Dynegy and DHI, respectively. We also received $175 million from the release of restricted cash on our consolidated balance sheets that was used to support our funding commitment to the Sandy Creek Project. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further information. The remaining $214 million of cash received upon closing the LS Power Transactions relates to the issuance of $235 million notes payable, and is included in Financing Activities. Please read "—Financing Activities" below and Note 18—Related Party Transactions for further discussion.

Additionally, during 2009, we sold the Heard County power generation facility for approximately $105 million, net of transaction costs. Please read Note 4— Dispositions, Contract Terminations and Discontinued Operations—Discontinued Operations—Heard County for further discussion.

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. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations 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 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. We have previously indicated that we consider our investment in PPEA Holding a non-core asset and intend to pursue alternatives regarding our remaining ownership interest.

Other Investing Activities. Cash inflows related to short-term investments during the year ended December 31, 2009 totaled $17 million and $16 million for Dynegy and DHI, respectively, reflecting a distribution from our short-term investments. Cash outflows related to short-term investments during the year ended December 31, 2008 totaled $27 million and $25 million for Dynegy and DHI, respectively, as a result of a reclassification from cash equivalents to short-term investments.

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 14—Variable Interest Entities—Sandy Creek for further discussion.

We paid $128 million, net of cash acquired, during the year ended December 31, 2007 in connection with the completion of the LS Power Merger. Please read Note 3—Business Combinations and Acquisitions—LS Power Business Combination for more information.

There was a $190 million cash inflow during the year ended December 31, 2009 for both Dynegy and DHI, related to changes in restricted cash balances primarily due to the release of $175 million of restricted cash that was used to support our funding commitment to the Sandy Creek Project. 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.

DHI's affiliate transactions during the year ended December 31, 2009 included $97 million related to the LS Power Transactions. Dynegy repurchased 245 million of its Class B shares with a fair value of $443 million (based on a share price of $1.81 on November 30, 2009) from LS Power by exchanging assets owned by DHI for the shares. In order to effect this exchange, Dynegy paid $540 million cash to a subsidiary of LS Power in exchange for the shares, immediately following which a separate subsidiary of LS Power paid $540 million of cash to DHI in exchange for the assets. The $97 million represents the difference between the $540 million cash received by DHI and the $443 million fair value of the shares received by Dynegy.

Other included $3 million of insurance proceeds received during the year ended December 31, 2009. Other included $7 million of insurance proceeds received during the year ended December 31, 2008. Additionally, included in Other for Dynegy for the year ended December 31, 2008 is $4 million of proceeds from the liquidation of an investment.

Financing Activities

Historical Cash Flow from Financing Activities. Dynegy's net cash used in financing activities during the twelve months ended December 31, 2009 totaled $608 million. Repayments of borrowings were $890 million, and consisted of the following:

- $421 million in aggregate principal amount on our 6.875 percent senior unsecured notes due 2011 ("2011 Notes");
- $412 million in aggregate principal amount on our 8.75 percent senior unsecured notes due 2012 ("2012 Notes"); and
- $57 million in aggregate principal amount on our Sithe 9.00 percent secured bonds due 2013.

We also paid debt extinguishment costs of $46 million in connection with the repayment of the 2011 Notes and 2012 Notes.

These payments were partially offset by $328 million of net proceeds from the following borrowings:

- $130 million under the PPEA Credit Agreement Facility; and
- $214 million of cash proceeds from the LS Power Transactions allocated to the issuance of $235 million 7.5 percent senior unsecured notes due 2015.

These borrowings were partly offset by $16 million of financing fees related to the Credit Facility Amendment No. 4.

DHI's net cash used in financing activities during the twelve months ended December 31, 2009 totaled $1,193 million. This included the net $608 million used in repayments and extinguishment costs, net of borrowings, incurred by Dynegy, as set forth above, as well as $585 million in aggregate dividend payments to Dynegy.

Dynegy's net cash provided by financing activities during the twelve months ended December 31, 2008 totaled $148 million and DHI's net cash provided by financing activities during the twelve months ended December 31, 2008 totaled $146 million. The cash provided by financing activities primarily related to $192 million of proceeds from borrowings under the PPEA 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 of $369 million also includes dividend payments of $342 million to Dynegy.

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, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in millions)	
First secured obligations	$ 918	$ 919
Unsecured obligations	3,645	4,245
Lease obligations (1)	626	700
Total corporate obligations	5,189	5,864
PPEA and Sithe secured non-recourse obligations (2)	1,031	959
Total obligations	6,220	6,823
Less: Lease obligations (1)	(626)	(700)
Other (3)	(12)	13
Total notes payable and long-term debt (4)	$ 5,582	$ 6,136

(1) Represents present value of future lease payments associated with the DNE lease financing discounted at 10 percent.
(2) Includes PPEA's non-recourse project financing of $644 million and tax-exempt bonds of $100 million. Although we own a 37 percent interest in PPEA Holding, we consolidate PPEA Holding and the debt of its subsidiary, as we are the primary beneficiary of this VIE. Also includes project financing associated with our Independence facility. Please read Note 14—Variable Interest Entities for further discussion.
(3) Consists of net premiums (discounts) on debt of $(12) million at December 31, 2009 and $13 million at December 31, 2008.
(4) Does not include letters of credit.

Please read Note 17—Debt for further discussion of these items. Our debt maturity profile as of December 31, 2009 includes $63 million in 2010, $150 million in 2011, $164 million in 2012, $1,006 million in 2013, zero in 2014 and approximately $3,455 million thereafter. Maturities for 2010 represent principal payments on the Sithe Senior Notes.

In addition to the $63 million of debt maturities due in 2010, we have classified $744 million of PPEA's non-recourse project financing and tax-exempt bonds as current liabilities, as PPEA does not expect to be in compliance with certain restrictions of the applicable financing agreement within the next twelve months. These liabilities are non-recourse to us, and our obligation to support PPEA is limited to a $15 million letter of credit we have posted in support of our contingent equity contribution. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion.

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 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 Dynegy or DHI credit ratings or Dynegy's 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.

On October 16, 2009, Standard & Poor's downgraded PPEA's credit rating. Because of this downgrade, certain interest rate swaps to which PPEA is a party may be terminated by the counterparties if there is also a default by the insurer, Ambac, which provides financial guarantee insurance for the swaps. The termination value of the PPEA interest rate swaps at December 31, 2009 was approximately $80 million. Termination of the interest rate swaps, if not paid by PPEA, could result in the acceleration of the

PPEA debt. Our obligations related to our investment in PPEA, excluding the noncontrolling interest holders' obligation, are limited to a $15 million letter of credit issued under our Credit Facility to support our contingent equity contribution to PPEA. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion.

Financial Covenants. Our Credit Facility 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 (each as defined therein) for DHI and its relevant subsidiaries of no greater than a specified amount; and (ii) a covenant that requires DHI and certain of its subsidiaries to maintain a ratio of adjusted EBITDA to consolidated interest expense (each as defined therein) for DHI and its relevant subsidiaries as of the last day of the measurement periods as specified below of no less than a specified amount. The following table summarizes the required ratios:

Period Ended:	(i) Secured Debt : Adjusted EBITDA No greater than:	(ii) Adjusted EBITDA : Interest Expense No less than:
December 31, 2009	3.00 : 1	1.75 : 1
March 31, 2010	3.25 : 1	1.70 : 1
June 30, 2010	3.25 : 1	1.60 : 1
September 30, 2010	3.50 : 1	1.30 : 1
December 31, 2010	3.50 : 1	1.30 : 1
March 31, 2011	3.50 : 1	1.35 : 1
June 30, 2011	3.50 : 1	1.40 : 1
September 30, 2011	3.25 : 1	1.60 : 1
December 31, 2011	3.00 : 1	1.60 : 1
Thereafter	2.50 : 1	1.75 : 1

We are in compliance with these covenants as of December 31, 2009. We may in the future experience a reduction in availability under our Credit Facility as a result of EBITDA levels in future periods and a corresponding borrowing limitation under the secured debt to EBITDA covenant. Despite this potential reduction in our available liquidity, we believe we have sufficient liquidity and capital resources to support our operations for the next twelve months. Please read "Revolver Capacity" above for further discussion.

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. Please read Note 17—Debt—Credit Facility for further discussion of our amended credit facility.

Capital-Structuring 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, including public or private debt or equity issuances. Matters to be considered will include cash interest expense, covenant flexibility and maturity profile, all to be balanced with maintaining adequate liquidity. The timing of any transaction may be impacted by events, such as strategic growth opportunities, legal judgments or regulatory or environmental requirements as well as any decisions to seek an improved credit profile. 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, and our ability to issue equity securities is limited by the New Shareholder Agreement. This agreement provides that we will not issue Dynegy's equity securities for our own purposes until the earlier of (i) March 31, 2010 or (ii) the first date following closing of the transaction in which LS Power owns, in aggregate, less than 10 percent of Dynegy's then outstanding Class A common stock. Our ability to issue debt securities is limited by our financing agreements, including our Credit Facility.

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.

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, 2009 and it does not expect to pay a dividend on 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, "B3" by Moody's, and "B" by Fitch.

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, 2009. 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) (1)	$ 5,582	$ 807	$ 314	$ 1,006	$ 3,455
Interest payments on debt	2,992	377	744	738	1,133
Operating leases	1,026	120	333	312	261
Capital leases	10	2	4	3	1
Coal commitments (2)	391	253	134	4	—
Capacity payments	180	33	65	64	18
Interconnection obligations	18	1	2	2	13
Construction service agreements	340	26	85	96	133
Pension funding obligations	60	19	41	—	—
Other obligations	22	6	5	4	7
Total contractual obligations	$ 10,621	$ 1,644	$ 1,727	$ 2,229	$ 5,021

(1) Includes $644 million of PPEA's Construction Loan and $100 million of PPEA's Tax Exempt Bonds. We have classified this $744 million in current liabilities, as PPEA does not expect to be in compliance with certain restrictions of the applicable financing agreement within the next twelve months. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion.

(2) Included based on nature of purchase obligations under associated contracts.

Long-Term Debt (Including Current Portion). Total amounts of Long-term debt (including current portion) are included in the December 31, 2009 consolidated balance sheet. Please read Note 17—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 17—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 2010 through 2012, and approximately $17 million in aggregate for the period 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. We have 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. We have 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 $10 million over the remaining term of the lease.

Coal Commitments. At December 31, 2009, we had contracts in place to supply coal to various of our generation facilities with minimum commitments of $391 million. Obligations related to the purchase of coal were $372 million through 2012, and obligations related to the transportation were $19 million through 2013.

Capacity Payments. Capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $180 million.

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 plant maintenance agreements. Our obligation under these agreements is approximately $340 million.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations for 2010—$19 million, 2011—$11 million and 2012—$30 million. These amounts reflect increases over prior amounts resulting from declines in investment 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 2012, we cannot confidently estimate the amount of such obligations at this time and, therefore, have not included them in the table above. Please read Note 23—Employee Compensation, Savings and Pension Plans—Pension and Other Post-Retirement Benefits—Obligations and Funded Status for further discussion.

Other Obligations. Other obligations include the following items:

- Payments associated with a capacity contract between Independence and Con Edison. The aggregate payments through the 2014 expiration are approximately $11 million as of December 31, 2009; and
- Reserves of $5 million recorded in connection with uncertain tax positions. Please read Note 19—Income Taxes—Unrecognized Tax Benefits for further discussion.

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2009 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)	$ 536	$ 458	$ 78	$ —	$ —
Surety bonds (2)	8	8	—	—	—
Guarantees	1	—	1	—	—
Total financial commitments	$ 545	$ 466	$ 79	$ —	$ —

(1) Amounts include outstanding letters of credit.
(2) Surety bonds are generally on a rolling 12-month basis. The $8 million of surety bonds are primarily 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, 2009, future lease payments are $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, 2009, the present value (discounted at 10 percent) of future lease payments was $626 million.

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

	2009	2008	2007
		(in millions)	
Lease Expense	$ 50	$ 50	$ 50
Lease Payments (Cash Flows)	$ 141	$ 144	$ 107

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, 2009, the termination payment at par would be approximately $853 million for all of the leased 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 21—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, 2009, 2008 and 2007. 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 and how we allocate our resources, we report the results of each business as a separate segment in our consolidated financial statements. The results of our legacy operations, including CRM, are included in Other. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization. Our 50 percent investment in SCH, which was sold in the fourth quarter 2009, is included in GEN-WE for reporting purposes. 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 2009, 2008 and 2007, respectively.

Dynegy's Results of Operations for the Year Ended December 31, 2009

	Power Generation GEN-MW	Power Generation GEN-WE	Power Generation GEN-NE	Other	Total
			(in millions)		
Revenues	$ 1,257	$ 380	$ 834	$ (3)	$ 2,468
Cost of sales	(505)	(156)	(534)	1	(1,194)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(222)	(120)	(181)	4	(519)
Depreciation and amortization expense	(215)	(62)	(47)	(11)	(335)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	(147)	—	(391)	—	(538)
Loss on sale of assets	(96)	—	(28)	—	(124)
General and administrative expense	—	—	—	(159)	(159)
Operating loss	$ (4)	$ (218)	$ (444)	$ (168)	$ (834)
Earnings (losses) from unconsolidated investments	—	(72)	—	1	(71)
Other items, net	2	3	1	5	11
Interest expense and debt extinguishment costs					(461)
Loss from continuing operations before income taxes					(1,355)
Income tax benefit					315
Loss from continuing operations					(1,040)
Loss from discontinued operations, net of taxes					(222)
Net loss					(1,262)
Less: Net loss attributable to the noncontrolling interests					(15)
Net loss attributable to Dynegy Inc.					$ (1,247)

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	$ 1,621	$ 702	$ 1,006	$ (5)	$ 3,324
Cost of sales	(583)	(415)	(705)	10	(1,693)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(203)	(98)	(180)	15	(466)
Depreciation and amortization expense	(205)	(77)	(54)	(10)	(346)
Gain on sale of assets	56	11	—	15	82
General and administrative expense	—	—	—	(157)	(157)
Operating income (loss)	$ 686	$ 123	$ 67	$ (132)	$ 744
Losses from unconsolidated investments	—	(40)	—	(83)	(123)
Other items, net	—	5	6	73	84
Interest expense					(427)
Income from continuing operations before income taxes					278
Income tax expense					(90)
Income from continuing operations					188
Loss from discontinued operations, net of taxes					(17)
Net income					171
Less: Net loss attributable to the noncontrolling interests					(3)
Net income attributable to Dynegy Inc.					$ 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	$ 1,323	$ 506	$ 1,076	$ 13	$ 2,918
Cost of sales	(481)	(286)	(688)	19	(1,436)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(190)	(67)	(179)	(4)	(440)
Depreciation and amortization expense	(193)	(55)	(45)	(13)	(306)
Gain on sale of assets	39	—	—	4	43
General and administrative expense	—	—	—	(203)	(203)
Operating income (loss)	$ 498	$ 98	$ 164	$ (184)	$ 576
Earnings (losses) from unconsolidated investments	—	6	—	(9)	(3)
Other items, net	—	—	—	56	56
Interest expense					(384)
Income from continuing operations before income taxes					245
Income tax expense					(140)
Income from continuing operations					105
Income from discontinued operations, net of taxes					166
Net income					271
Less: Net income attributable to the noncontrolling interests					7
Net income attributable to Dynegy Inc.					$ 264

The following tables provide summary financial data regarding DHI's consolidated and segmented results of operations for 2009, 2008 and 2007, respectively.

DHI's Results of Operations for the Year Ended December 31, 2009

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$ 1,257	$ 380	$ 834	$ (3)	$ 2,468
Cost of sales	(505)	(156)	(534)	1	(1,194)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(222)	(120)	(181)	2	(521)
Depreciation and amortization expense	(215)	(62)	(47)	(11)	(335)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	(147)	—	(391)	—	(538)
Loss on sale of assets	(96)	—	(28)	—	(124)
General and administrative expense	—	—	—	(159)	(159)
Operating loss	$ (4)	$ (218)	$ (444)	$ (170)	$ (836)
Losses from unconsolidated investments	—	(72)	—	—	(72)
Other items, net	2	3	1	4	10
Interest expense and debt extinguishment costs					(461)
Loss from continuing operations before income taxes					(1,359)
Income tax benefit					313
Loss from continuing operations					(1,046)
Loss from discontinued operations, net of taxes					(222)
Net loss					(1,268)
Less: Net loss attributable to the noncontrolling interests					(15)
Net loss attributable to Dynegy Holdings Inc.					$ (1,253)

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	$ 1,621	$ 702	$ 1,006	$ (5)	$ 3,324
Cost of sales	(583)	(415)	(705)	10	(1,693)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(203)	(98)	(180)	15	(466)
Depreciation and amortization expense	(205)	(77)	(54)	(10)	(346)
Gain on sale of assets	56	11	—	15	82
General and administrative expense	—	—	—	(157)	(157)
Operating income (loss)	$ 686	$ 123	$ 67	$ (132)	$ 744
Losses from unconsolidated investments	—	(40)	—	—	(40)
Other items, net	—	5	6	72	83
Interest expense					(427)
Income from continuing operations before income taxes					360
Income tax expense					(138)
Income from continuing operations					222
Loss from discontinued operations, net of taxes					(17)
Net income					205
Less: Net loss attributable to the noncontrolling interests					(3)
Net income attributable to Dynegy Holdings Inc.					$ 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	$ 1,323	$ 506	$ 1,076	$ 13	$ 2,918
Cost of sales	(481)	(286)	(688)	19	(1,436)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(190)	(67)	(179)	(4)	(440)
Depreciation and amortization expense	(193)	(55)	(45)	(13)	(306)
Gain on sale of assets	39	—	—	4	43
General and administrative expense	—	—	—	(184)	(184)
Operating income (loss)	$ 498	$ 98	$ 164	$ (165)	$ 595
Earnings from unconsolidated investments	—	6	—	—	6
Other items, net	—	—	—	53	53
Interest expense					(384)
Income from continuing operations before income taxes					270
Income tax expense					(105)
Income from continuing operations					165
Income from discontinued operations, net of taxes					166
Net income					331
Less: Net income attributable to the noncontrolling interests					7
Net income attributable to Dynegy Holdings Inc.					$ 324

The following table provides summary segments operating statistics for the years ended December 31, 2009, 2008 and 2007, respectively:

	Year Ended December 31,		
	2009	2008	2007
GEN-MW			
Million Megawatt Hours Generated (1)	24.9	24.4	24.9
In Market Availability for Coal Fired Facilities (2)	90%	90%	93%
Average Capacity Factor for Combined Cycle Facilities (3)	29%	16%	19%
Average Quoted On-Peak Market Power Prices ($/MWh) (4):			
Cinergy (Cin Hub)	$ 35	$ 67	$ 61
Commonwealth Edison (NI Hub)	$ 35	$ 66	$ 59
PJM West	$ 45	$ 84	$ 71
Average On-Peak Market Spark Spreads ($/MWh) (5):			
PJM West	$ 12	$ 15	$ 17
GEN-WE			
Million Megawatt Hours Generated (6) (7)	5.6	8.6	7.7
Average Capacity Factor for Combined Cycle Facilities (3)	41%	65%	75%
Average Quoted On-Peak Market Power Prices ($/MWh) (4):			
North Path 15 (NP 15)	$ 39	$ 80	$ 67
Palo Verde	$ 35	$ 72	$ 62
Average On-Peak Market Spark Spreads ($/MWh) (5):			
North Path 15 (NP 15)	$ 8	$ 18	$ 16
Palo Verde	$ 7	$ 13	$ 13
GEN-NE			
Million Megawatt Hours Generated	10.2	7.9	9.4
In Market Availability for Coal Fired Facilities (2)	95%	91%	90%
Average Capacity Factor for Combined Cycle Facilities (3)	44%	25%	37%
Average Quoted On-Peak Market Power Prices ($/MWh) (4):			
New York—Zone G	$ 50	$ 101	$ 84
New York—Zone A	$ 36	$ 68	$ 64
Mass Hub	$ 46	$ 91	$ 78
Average On-Peak Market Spark Spreads ($/MWh) (5):			
New York—Zone A	$ 4	$ 3	$ 12
Mass Hub	$ 12	$ 23	$ 23
Fuel Oil	$ (53)	$ (37)	$ (16)
Average natural gas price—Henry Hub ($/MMBtu) (8)	$ 3.92	$ 8.85	$ 6.95

(1) Excludes less than 0.1 million MWh generated by our Bluegrass power generation facility, which we sold on November 30, 2009 and is reported in discontinued operations, for the years ended December 31, 2009, 2008 and 2007.

(2) Reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched.

(3) Reflects actual production as a percentage of available capacity. Excludes the Arizona power generation facilities which are reported as discontinued operations with respect to the GEN-WE segment.

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

(5) 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 us.

(6) 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, 2009, 2008 and 2007, respectively.
(7) Excludes approximately 1.8 million MWh generated by our CoGen Lyondell power generation facility, which we sold in August 2007 and is reported in discontinued operations, for the year ended December 31, 2007. Excludes less than 0.1 million MWh generated by our Calcasieu and Heard County power generation facilities, which we sold on March 31, 2008 and April 30, 2009, respectively, and are reported in discontinued operations, for the years ended December 31, 2009, 2008 and 2007. Excludes approximately 2.4 million MWh, 2.6 million MWh and 3.4 million MWh generated by our Arizona power generation facilities, which we sold on November 30, 2009 and is reported in discontinued operations, for the years ended December 31, 2009, 2008 and 2007.
(8) 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, 2009				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Impairments (1)	$ (246)	$ (495)	$ (488)	$ —	$ (1,229)
Loss on extinguishment of debt (2)	—	—	—	(46)	(46)
Loss on LS Power Transactions (3)	(118)	(82)	(28)	—	(228)
Loss on sale of Sandy Creek Project (4)	—	(84)	—	—	(84)
Sandy Creek Project mark-to-market gains (5)	—	21	—	—	21
Gain on sale of Heard County (6)	—	10	—	—	10
Taxes (7)	—	—	—	(26)	(26)
Total—DHI	(364)	(630)	(516)	(72)	(1,582)
Taxes (7)	—	—	—	(7)	(7)
Total—Dynegy	$ (364)	$ (630)	$ (516)	$ (79)	$ (1,589)

(1) Includes $258 million of impairment charges related to our Arizona and Bluegrass power generation facilities which are included in discontinued operations.
(2) Related to debt extinguishment costs for repurchase of the 2011 Notes and the 2012 Notes during the fourth quarter 2009.
(3) Includes $104 million of losses related to our Arizona and Bluegrass power generation facilities which are included in discontinued operations.
(4) The loss on sale of Dynegy's investment in the Sandy Creek Project to LS Power includes the recognition of $40 million in losses on interest rate swaps that were previously deferred in OCI. These charges are included in Losses from unconsolidated investments on our consolidated statements of operations.
(5) These mark-to-market gains represent our 50 percent share prior to the sale.
(6) Included in discontinued operations.
(7) Includes charges of $21 million for Dynegy and $16 million for DHI related to a change in California state law and charges of $12 million for Dynegy and $10 million for DHI due to revised assumptions around our ability to use certain state deferred tax assets.

	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
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 Project ownership interest	—	13	—	—	13
Gain on liquidation of foreign entity	—	—	—	24	24
The Sandy Creek Project mark-to-market losses (1)	—	(40)	—	—	(40)
Taxes (2)	—	—	—	12	12
Heard County impairment (3)	—	(47)	—	—	(47)
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.
(3) Included in discontinued operations.

	Year Ended December 31, 2007				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Gain on sale of CoGen Lyondell (1)	$ —	$ 224	$ —	$ —	$ 224
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 (2)	—	—	—	30	30
Total—DHI	5	234	—	83	322
Legal and settlement charges	—	—	—	(19)	(19)
Taxes (2)	—	—	—	(20)	(20)
Total—Dynegy	$ 5	$ 234	$ —	$ 44	$ 283

(1) Included in discontinued operations.
(2) Represents adjustments arising from the measurement of temporary differences.

Year Ended 2009 Compared to Year Ended 2008

Operating Income (Loss)

Operating loss for Dynegy was $834 million for the year ended December 31, 2009, compared to operating income of $744 million for the year ended December 31, 2008. Operating loss for DHI was $836 million for the year ended December 31, 2009, compared to operating income of $744 million for year ended December 31, 2008.

Our operating loss for the year ended December 31, 2009 was driven, in large part, by $538 million of asset impairments, a $433 million impairment of goodwill and a $124 million fourth quarter 2009 loss on the closing of the LS Power Transactions. Please read Note 15—Goodwill for further discussion of the goodwill impairments, Note 6—Impairment Charges for further discussion of the asset impairments and Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion of the loss on the LS Power Transactions.

Mark-to-market losses on forward sales of power associated with our generating assets are included in Revenues in the consolidated statements of operations. Such losses, which totaled $180 million for the year ended December 31, 2009, were a result of the expiration of certain risk management positions during 2009, for which earnings were recognized in prior periods. These losses compared to $252 million of mark-to-market gains for the year ended December 31, 2008, when forward market power prices decreased during the period.

We do not designate our commodity derivative instruments as cash flow hedges for accounting purposes. Please read Note 7—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. As a result, 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, 2009, the expected cash impact of the settlement of our open positions (which amounted to a $17 million net asset at December 31, 2009) will be recognized over time largely through the end of 2010 and 2011 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 loss for GEN-MW was $4 million for the year ended December 31, 2009, compared to operating income of $686 million for the year ended December 31, 2008. Such amounts do not include results from our Bluegrass power generating facility, which has been reclassified as a discontinued operation for all periods presented.

Revenues for the year ended December 31, 2009 decreased by $364 million compared to the year ended December 31, 2008, cost of sales decreased by $78 million and operating and maintenance expense increased by $19 million, resulting in a net decrease of $305 million. The decrease was primarily driven by the following:

- Mark-to-market losses – GEN-MW's results for the year ended December 31, 2009 included mark-to-market losses of $112 million related to forward sales, compared to $191 million of mark-to-market gains for the year ended December 31, 2008. Of the $112 million in 2009 mark-to-market losses, $137 million of losses related to positions that settled in 2009 representing mark-to-market gains recognized in previous periods, partly offset by $25 million of gains related to positions that will settle in 2010 and beyond;
- Decreased tolling/capacity revenues – Tolling revenues decreased by $58 million as a result of expiring contracts at our Kendall and Rocky Road facilities. This decrease is partially offset by a $43 million increase in capacity sales due to improved capacity pricing plus the additional capacity we were able to sell from the previously tolled facilities;

- Increased operating expense – operating expense increased from $203 million for year ended December 31, 2008 to $222 million for the year ended December 31, 2009, primarily as a result of planned outages at our coal-fired power generating facilities; and
- Lower revenues of $13 million from sales of emissions credits.

These items were partly offset by the following:

- Energy sales—GEN-MW's results from energy sales, including both physical and financial transactions, increased from $647 million for the year ended December 31, 2008 to $690 million for the year ended December 31, 2009. The negative impact of lower market power prices was more than offset by contracting 2009 volumes at higher energy prices, active management of swap positions, management of option positions and other commercial activities such as the sale and assignment of a multi-year power sales contract. Additionally, GEN-MW benefited from the reduced impact of basis differential between liquid market and power delivery prices and increased contributions from our natural gas combined-cycle facilities; and
- Midwest production volumes increased two percent due to higher run times associated with natural gas combined-cycle units, which benefited from coal-to-gas switching in PJM. Our coal volumes decreased primarily due to lower demand as a result of mild summer weather and economic impacts, as well as transmission line outages, increased off-peak wind generation and imports.

Depreciation expense increased from $205 million for the year ended December 31, 2008 to $215 million for the year ended December 31, 2009, primarily as a result of projects associated with the Midwest Consent Decree being placed into service. The increase in depreciation was partly offset by the impact of the assets sold to LS Power in 2009.

Operating income for the year ended December 31, 2009 included a pre-tax charge of approximately $76 million for the impairment of goodwill, reflected in Goodwill impairment on our consolidated statements of operations. Please read Note 15—Goodwill for further discussion.

In addition, for the year ended December 31, 2009, we recorded $147 million of impairments of our Renaissance, Riverside/Foothills, Rocky Road and Tilton power generating facilities and related assets, reflected in Impairment and other charges on our consolidated statements of operations. Please read Note 6—Impairment Charges for further discussion.

Operating income for the year ended December 31, 2009 included a $96 million pre-tax charge from sale of our Renaissance, Riverside/Foothills, Rocky Road and Tilton power generating facilities to LS Power, reflected in Gain (loss) on sale of assets in our consolidated statements of operations. 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 (loss) on sale of assets in our consolidated statements of operations.

Power Generation—West Segment. Operating loss for GEN-WE was $218 million for the year ended December 31, 2009, compared to operating income of $123 million for the year ended December 31, 2008. Such amounts do not include results from our Arizona and Heard County power generating facilities, which have been classified as discontinued operations for all periods presented.

Revenues for the year ended December 31, 2009 decreased by $322 million compared to the year ended December 31, 2008, cost of sales decreased by $259 million and operating and maintenance expense increased by $22 million, resulting in a net decrease of $85 million. The decrease was primarily driven by the following:

- Mark-to-market losses – GEN-WE's results for the year ended December 31, 2009 included mark to-market losses of $58 million, compared to $50 million of mark-to-market gains for the year ended December 31, 2008. Of the $58 million in 2009 mark-to-market losses, $15 million related to positions that settled in 2009, and the remaining $43 million related to positions that will settle in 2010 and beyond;

- Energy sales—GEN-WE's results from energy sales, including both physical and financial transactions, decreased from $98 million for the year ended December 31, 2008 to $94 million for the year ended December 31, 2009, primarily as a result of lower market spark spreads;
- Decreased volumes – Generated volumes were 5.6 million MWh for the year ended December 31, 2009, down from 8.6 million MWh for the year ended December 31, 2008. The volume decrease was driven in large part by decreased market spark spreads and reduced dispatch opportunities; and
- Increased operating expense – operating expense increased from $98 million for the year ended December 31, 2008 to $120 million for the year ended December 31, 2009, primarily as a result of planned outages at our Moss Landing facility as well as severance and employee retirement obligations associated with our South Bay facility.

These decreases were partly offset by increased tolling and capacity revenues of $46 million.

Depreciation expense decreased from $77 million for year ended December 31, 2008 to $62 million for the year ended December 31, 2009, largely as a result of an increase in the estimated useful life of one of our generation facilities.

Operating loss for the year ended December 31, 2009 included a pre-tax charge of approximately $260 million for the impairment of goodwill, reflected in Goodwill impairments in our consolidated statements of operations. Please read Note 15—Goodwill for further discussion.

In May 2008, we sold our beneficial interest in Oyster Creek Limited for approximately $11 million, and recognized a gain on the sale of approximately $11 million, reflected in Gain (loss) on sale of assets in our consolidated statements of operations. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—Oyster Creek for further discussion.

Power Generation—Northeast Segment. Operating loss for GEN-NE was $444 million for the year ended December 31, 2009, compared to operating income of $67 million for the year ended December 31, 2008.

Revenues for the year ended December 31, 2009 decreased by $172 million compared to the year ended December 31, 2008, cost of sales decreased by $171 million and operating and maintenance expense increased by $1 million, resulting in a net decrease of $2 million. The decrease was primarily driven by the following:

- Mark-to-market losses – GEN-NE's results for the year ended December 31, 2009 included mark-to-market losses of $10 million related to forward sales, compared to gains of $11 million for the year ended December 31, 2008. Of the $10 million in 2009 mark-to-market losses, $1 million related to positions that settled in 2009 and the remaining $9 million related to positions that will settle in 2010 and beyond;
- A coal inventory write-down of approximately $11 million recorded during the year ended December 31, 2009; and
- Increased emission allowance costs of approximately $17 million to operate our Northeast facilities due to RGGI requirements that began January 1, 2009.

These items were partly offset by the following:

- Energy sales—GEN-NE's results from energy sales, including both physical and financial transactions, increased from $98 million for the year ended December 31, 2008 to $120 million for the year ended December 31, 2009. The negative impact from lower market prices was more than offset by contracting 2009 volumes at higher energy prices, active management of swap positions and other commercial activities;

- Additional capacity sales of $14 million;
- Increased sales of emission credits of $7 million; and
- Increased volumes – Volumes produced by our natural gas-fired combined cycle fleet increased as a result of reduced congestion and improved dispatch opportunities at our Independence facility, as well as a reduction in transmission outages at our Casco Bay facility.

Depreciation expense decreased from $54 million for the year ended December 31, 2008 to $47 million for the year ended December 31, 2009, primarily due to the 2009 sale of our Bridgeport power generating facility and the 2009 impairments of our Roseton and Danskammer power generation facilities.

Operating loss for the year ended December 31, 2009 included a pre-tax charge of approximately $97 million for the impairment of goodwill, reflected in Goodwill impairments in our consolidated statements of operations. Please read Note 15—Goodwill for further discussion.

In addition, we recorded a $179 million impairment of our Bridgeport power generating facility and related assets, reflected in Impairment and other charges in our consolidated statements of operations. We also recorded a $212 million impairment of our Roseton and Danskammer power generation facilities and related assets, which is also reflected in Impairment and other charges in our consolidated statements of operations. Please read Note 6—Impairment Charges for further discussion.

Operating loss for the year ended December 31, 2009 included a $28 million pre-tax charge from the sale of our Bridgeport power generating facility to LS Power, reflected in Gain (loss) on sale of assets in our consolidated statements of operations.

Other. Dynegy's other operating loss for the year ended December 31, 2009 was $168 million, compared to an operating loss of $132 million for the year ended December 31, 2008. DHI's other operating loss for the year ended December 31, 2009 was $170 million, compared to an operating loss of $132 million for year ended December 31, 2008. Operating losses in both periods were comprised primarily of general and administrative expenses.

Cost of sales for the year ended December 31, 2008 included a benefit from the release of a $9 million liability associated with an assignment of a natural gas transportation contract. Operating and maintenance expense for the year ended December 31, 2008 included a benefit from the release of $16 million of sales and use tax liability.

Gain on sale of assets for the year ended December 31, 2008 included an approximate $15 million gain related to our sale of our remaining NYMEX shares and both membership seats.

Consolidated general and administrative expenses increased from $157 million from the year ended December 31, 2008 to $159 million for the year ended December 31, 2009.

Losses from Unconsolidated Investments

Dynegy's and DHI's losses from unconsolidated investments were $71 million and $72 million, respectively, for the year ended December 31, 2009. The loss includes a loss of $84 million on the sale of our investment in the Sandy Creek Project to LS Power partially offset by equity earnings of $12 million. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion. In addition, Dynegy recorded $1 million of earnings related to its former investment in DLS Power Development, included in Other.

Dynegy's and DHI's losses from unconsolidated investments were $123 million and $40 million, respectively, for the year ended December 31, 2008. $83 million of Dynegy's losses related to its investment in DLS Power Development. 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. Additionally, Dynegy and DHI 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 14—Variable Interest Entities—Sandy Creek Project for further discussion.

Other Items, Net

Dynegy's and DHI's other items, net, totaled $11 million and $10 million of income, respectively, for the year ended December 31, 2009, compared to $84 million and $83 million, respectively, of income for the year ended December 31, 2008. The decrease is primarily associated with approximately $42 million of lower interest income due to lower LIBOR rates in 2009. In addition, 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. Furthermore, 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.

Interest Expense

Dynegy's and DHI's interest expense and debt extinguishment costs totaled $461 million for the year ended December 31, 2009, compared to $427 million for the year ended December 31, 2008. The increase was primarily attributable to $46 million related to debt extinguishment costs for the 2011 Notes and 2012 Notes and $16 million of expense related to the change in value and dedesignation of interest rate swaps associated with PPEA's Credit Agreement Facility in 2009. These items were partly offset by a decrease in LIBOR rates on our variable-rate debt in 2009.

Income Tax Benefit (Expense)

Dynegy reported an income tax benefit from continuing operations of $315 million for the year ended December 31, 2009, compared to an income tax expense from continuing operations of $90 million for the year ended December 31, 2008. The 2009 effective tax rate was 23 percent, compared to 32 percent in 2008.

DHI reported an income tax benefit from continuing operations of $313 million for the year ended December 31, 2009, compared to an income tax expense of $138 million from continuing operations for the year ended December 31, 2008. The 2009 effective tax rate was 23 percent, compared to 38 percent in 2008.

The difference between the statutory rate of 35 percent and the effective rate of 23 percent for Dynegy and DHI for the year ended December 31, 2009 resulted primarily from the effect of the non-deductible goodwill impairment charge, non-deductible losses from the LS Power Transactions and state income taxes in the taxing jurisdictions in which our assets operate. The income tax benefit for the year ended December 31, 2009 included an overall state tax benefit resulting from current year losses, changes in our state sales profile, the exit from various states due to the LS Power Transactions, and charges of $21 million and $16 million recorded by Dynegy and DHI, respectively, resulting from a change in California state tax law. We also revised our assumptions around the ability to utilize certain state deferred tax assets, and therefore Dynegy and DHI recorded valuation allowances resulting in additional state tax expense of $12 million and $10 million, respectively, during 2009.

For the period ended December 31, 2008, the difference between the effective rates of 32 and 38 percent for Dynegy and DHI, respectively, and the statutory rate of 35 percent resulted primarily from the effect of state income taxes in the taxing jurisdictions in which our assets operate. In addition, the 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 as well as a benefit of $18 million and $12 million for Dynegy and DHI, respectively, related to adjustments to state tax expense arising from the measurement of temporary differences.

Discontinued Operations

Loss From Discontinued Operations Before Taxes

For the year ended December 31, 2009, our pre-tax loss from discontinued operations was $343 million ($222 million after-tax), related to the operation of our Arizona, Bluegrass and Heard County facilities. Our GEN-WE segment included pre-tax impairment charges of $235 million ($143 million after-tax) related to our Arizona power generation facilities and a pre-tax loss of $82 million ($50 million after-tax) on the completion of the LS Power Transactions. Additionally, the GEN-WE segment included a pre-tax gain on sale of $10 million ($6 million after-tax) related to our Heard County power generation facility. Our GEN-MW segment included pre-tax impairment charges of $23 million ($14 million after-tax) related to our Bluegrass power generating facility and a pre-tax loss on the completion of the LS Power Transactions of $22 million ($13 million after-tax) .

For the year ended December 31, 2008, our pre-tax loss from discontinued operations was $31 million ($17 million after-tax). Dynegy's GEN-WE segment included a pre-tax impairment charge of $47 million ($27 million after-tax) of our Heard County power generating facility partly offset by $14 million ($8 million after-tax) of income from the operation of our Arizona power generation facilities. Dynegy's GEN-MW segment included losses of $2 million ($1 million after-tax) from the operation of the Bluegrass power generating facility. In addition, Dynegy recorded income of $4 million ($3 million after-tax) related to the receipt of business interruption insurance proceeds in its former NGL segment.

Income Tax Benefit From Discontinued Operations

We recorded an income tax benefit from discontinued operations of $121 million during the year ended December 31, 2009, compared to an income tax benefit of $14 million during the year ended December 31, 2008. These amounts reflect effective rates of 35 percent and 45 percent, respectively.

Noncontrolling Interest

We recorded $15 million of noncontrolling interest losses for the year ended December 31, 2009, compared with $3 million of noncontrolling interest losses for the year ended December 31, 2008 related to our investment in PPEA Holding. The change in noncontrolling interest losses is primarily related to mark-to-market losses and current period settlements recognized in 2009 related to the interest rate swap agreements associated with the PPEA Credit Agreement Facility. Effective July 28, 2009, the interest rate swap agreements were no longer accounted for as a cash flow hedges; therefore, the change in mark-to-market value is reflected in our consolidated statement of operations and is no longer reflected in accumulated other comprehensive loss.

Year Ended 2008 Compared to Year Ended 2007

Operating Income

Operating income for Dynegy was $744 million for the year ended December 31, 2008, compared to $576 million for the year ended December 31, 2007. Operating income for DHI was $744 million for the year ended December 31, 2008, compared to $595 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 $252 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 7—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 $686 million for the year ended December 31, 2008, compared to $498 million for the year ended December 31, 2007. Such amounts do not include results from the Bluegrass power generation facility, which has been classified as a discontinued operation for all periods presented prior to disposition.

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 $13 million, resulting in a net increase of $183 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 24.9 million MWh for the year ended December 30, 2007, to 24.4 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 $193 million for the year ended December 31, 2007 to $205 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 $123 million for the year ended December 31, 2008, compared to operating income of $98 million for the year ended December 31, 2007. Such amounts do not include results from the CoGen Lyondell, Calcasieu, Heard County, and Arizona power generation facilities, which have been classified as discontinued operations for all periods presented prior to disposition.

Revenues for the year ended December 31, 2008 increased by $196 million compared to the year ended December 31, 2007, cost of sales increased by $129 million and operating and maintenance expense increased by $31 million, resulting in a net increase of $36 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 $50 million, compared to $32 million of mark-to-market gains for the year ended December 31, 2007. Of the $50 million in 2008 mark-to-market gains, $2 million of losses related to positions that settled in 2008, and the remaining $52 million related to positions that will settle in 2009 and 2010; and
- Increased volumes – Generated volumes were 8.6 million MWh for the year ended December 31, 2008, up from 7.7 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 $143 million for the year ended December 31, 2008, compared with $111 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. Depreciation expense increased from $55 million for the year ended December 31, 2007 to $77 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 LS Power 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.

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 14—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 14—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 $84 million of income for the year ended December 31, 2008, compared to $56 million of income for the year ended December 31, 2007. DHI's other items, net, totaled $83 million of income for the year ended December 31, 2008, compared to $53 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. 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 Facility. 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 PPEA Credit Agreement Facility. Effective July 1, 2007, these interest rate swap 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 $90 million for the year ended December 31, 2008, compared to an income tax expense from continuing operations of $140 million for the year ended December 31, 2007. The 2008 effective tax rate was 32 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 $138 million for the year ended December 31, 2008, compared to an income tax expense from continuing operations of $105 million for the year ended December 31, 2007. The 2008 effective tax rate was 38 percent, compared to 39 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 (Loss) From Discontinued Operations Before Taxes

During the year ended December 31, 2008, Dynegy's pre-tax loss from discontinued operations was $31 million ($17 million after-tax). Dynegy's GEN-WE segment included a $47 million impairment of our Heard County power generating facility partly offset by $14 million of income from the operation of our Arizona power generation facilities. Dynegy's GEN-MW segment included losses of $2 million from the operation of the Bluegrass power generating facility. In addition, Dynegy recorded income of $4 million related to the receipt of business interruption insurance proceeds in its former NGL segment. During the year ended December 31, 2007, Dynegy's pre-tax income from discontinued operations was $268 million ($166 million after-tax). Dynegy's GEN-WE segment included $257 million from the operation of the CoGen Lyondell, Calcasieu, Heard County and Arizona power generation facilities, which includes a pre-tax gain of $224 million associated with the completion of our sale of the CoGen Lyondell power generation facility. Dynegy's GEN-MW segment included losses of $3 million from the operation of the Bluegrass power generating 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 loss from discontinued operations was $31 million ($17 million after-tax). DHI's GEN-WE segment included a $47 million impairment of our Heard County power generating facility partly offset by $14 million of income from the operation of our Arizona power generation facilities. DHI's GEN-MW segment included losses of $2 million from the operation of the Bluegrass power generating facility. In addition, DHI recorded income of $4 million related to the receipt of business interruption insurance proceeds in its former NGL segment. During the year ended December 31, 2007, DHI's pre-tax income from discontinued operations was $269 million ($166 million after-tax). DHI's GEN-WE segment included $225 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities which includes a pre-tax gain of $224 million associated with the completion of our sale of the CoGen Lyondell power generation facility. DHI's GEN-MW segment included losses of $3 million from the operation of the Bluegrass power generating facility. DHI's U.K. CRM business included income of $15 million, primarily related to a favorable settlement of a legacy receivable.

Income Tax Benefit (Expense) From Discontinued Operations

We recorded an income tax benefit from discontinued operations of $14 million during the year ended December 31, 2008, compared to an income tax expense of $102 million for Dynegy and $103 million for DHI for the year ended December 31, 2007. The effective rates for the years ended December 31, 2008 and 2007 were 45 percent and 38 percent, respectively.

Noncontrolling Interest

We recorded $3 million of noncontrolling interest losses for the year ended December 31, 2008, compared with $7 million of noncontrolling interest income recorded in 2007 related to our investment in PPEA Holding. The change in noncontrolling 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" above for further discussion.

Outlook

Subsequent to the LS Power Transactions, our power generation portfolio consists of approximately 12,300 MW of generating capacity and continues to be diversified by fuel source (i.e., coal, natural gas and fuel oil) and dispatch type (i.e., baseload, intermediate and peaking facilities). Approximately 34 percent of our power generation fleet is natural gas-fired, combined-cycle capacity, 31 percent is baseload coal-fired capacity, 25 percent is natural gas-fired peaking capacity and the remaining 10 percent is dual-fuel capable. Of this capacity, our baseload coal-fired capacity accounts for the majority of our revenues and operating cash flows. We believe that our fuel and dispatch type diversity positions us to capture market opportunities that may not be available to less diverse generators.

Our power generation capacity also is diversified by geographic location across six U.S. states, as approximately 43 percent of our generating capacity is located in the Midwest, 32 percent is located in the West, and 25 percent is located in the Northeast. We believe that this geographic diversity will continue to position us to benefit from the portfolio effect of different supply/demand characteristics across broad geographic regions, including in the Northeast and California where new supply options may be limited. These different supply/demand characteristics can occur over the short-term (e.g., based on weather patterns or the unavailability of other suppliers) or over the long-term (e.g., based on long-term demand growth that exceeds supply additions).

We expect that our future financial results will continue to be sensitive to fuel and commodity prices, market structure and prices for electric energy, capacity and ancillary services, including pricing at our plant locations relative to pricing at their respective trading hubs, 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 forward markets. We also participate in various regional auctions and bilateral opportunities. Our regional commercial strategies are particularly driven by the types of facilities that we have within a given region and the operating characteristics of those facilities.

We have volumetrically hedged a substantial portion of our expected generation volumes through 2011. Based on specific market conditions, at any point in time we may enter into transactions that will increase or decrease the portion of our expected output that has been contracted. We may do this by buying back positions and selling at more attractive prices in an attempt to capture margin opportunities or mitigate downside risk associated with changes in commodity prices. However, our future operating cash flows may also vary based on a number of other factors, including the value of capacity and ancillary services, the operational performance of our generating facilities, the price differential between the locations where we deliver generated power and the liquid market hub and legal, environmental and regulatory requirements.

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

As previously described, there is a trend toward greater environmental regulation of all aspects of our business. As this trend continues it is likely that we will experience additional costs and limitations. Please read Business—Environmental Matters for further discussion.

The following summarizes unique business issues impacting the outlook of each of our three regions.

GEN-MW. Our Midwest Consent Decree requires substantial emission reductions from our Illinois coal-fired power plants and the completion of several supplemental environmental projects in the Midwest. We have achieved all emission reductions scheduled to date under the Midwest Consent Decree and are in the process of installing additional emission control equipment to meet future Midwest Consent Decree emission limits. We expect our costs associated with the Midwest Consent Decree projects, which we expect to incur through 2013, to be approximately $960 million, which includes approximately $545 million spent to date. This estimate includes a number of assumptions about uncertainties beyond our control, such as costs associated with labor and materials. 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 Midwest Consent Decree.

Our Midwest coal requirements are 100 percent contracted and priced through 2010. For 2011 and 2012, approximately 35 percent of our coal requirements are contracted, and the price for these volumes will be determined in 2010 under the terms of the coal purchase contract. Our Midwest coal transportation requirements are 100 percent contracted and priced through 2013. Our expected generation volumes are fully hedged through 2010 and approximately 75 percent hedged through 2011.

Lower day-ahead power prices, increased renewable generation, including wind, and depressed demand conditions within the MISO footprint continue to push coal-fired baseload resources to the margin of the supply stack. Lower day-ahead power prices can cause an increase in the cycling of coal-fired facilities, thus potentially increasing stress on equipment which can result in increased maintenance costs and plant outages. In addition, ongoing ISO transmission upgrades and maintenance projects have the possibility of negatively impacting one or more of our facilities' power prices for extended periods of time. We attempt to hedge some of these exposures through active participation in FTR markets, transmission resource planning and upgrade initiatives.

The increase in renewable generating resources within MISO and the continued expansion of MISO membership, coupled with load reductions due to unfavorable economic conditions and demand response initiatives, will continue to put downward pressure on capacity market prices as reserve margins are expected to reach 50 percent for winter 2010.

The MISO successfully implemented its ancillary services market in January 2009. We participate fleet-wide in this market, which allows us to provide additional products that are more highly valued. This results in additional revenue sources and opportunities to add value to the MISO and mitigate some of the negative impacts of cycling baseload facilities. Increased participation in this market by our combined-cycle facilities allows us to respond to favorable real-time market price moves and unexpected generation events within the PJM footprint.

In January 2010, we terminated an existing tolling agreement for approximately 280 MW of capacity at our Kendall facility which was contracted through 2017. A portion of this capacity has been recontracted through the same term. Freeing up additional capacity from this facility allows us to more effectively capture future market opportunities in PJM arising from energy, capacity and ancillary services markets.

GEN-WE. Approximately 70 percent of our power plant capacity in the West is contracted through 2011 under tolling agreements with load-serving entities and RMR agreements with the CAISO. A significant portion of the remaining capacity is sold as a resource adequacy product in the California market, and much of the expected production associated with our plants without tolls or RMR agreements has been financially hedged.

Our South Bay and Oakland power generation facilities are operating under RMR agreements with the CAISO through December 31, 2010. For 2010, the CAISO has designated Oakland and three of the five units at South Bay as RMR facilities. At South Bay, the removal of RMR status for Units 3 and 4 for 2010 resulted in the permanent retirement of those units at the end of 2009. The RMR designation by the CAISO for the remaining units at the South Bay facility is subject to being terminated early if the CAISO determines this facility is no longer needed to ensure local reliability. The South Bay facility will permanently cease operation upon the termination of RMR designation by the CAISO as per the terms of the lease with the Port of San Diego.

Upon retirement of the South Bay facility, we have a contractual obligation to demolish the plant and remediate specific parcels of the property. The costs associated with plant closure have been included in the 2010 RMR rate filing, as have any remaining, unfunded expected demolition and remediation costs. Full recovery of these costs will be subject to the ultimate disposition of these filed rates via a multi-party settlement or adjudication by the FERC.

GEN-NE. The Northeast portfolio includes two generating units with dual fuel capability. For our Danskammer power generation facility, we have secured approximately 80 percent of the physical coal supply requirements for 2010 with the remaining balance financially hedged. For volumetric power hedges in 2011, our coal supply requirement is financially hedged.

While we have sourced most of our coal from South America, we have access to and are exploring multiple options for the balance of our 2010 and 2011 supply needs. Coal prices in both the international and domestic markets have retreated from their historic highs reached in the middle of 2008. We continue to explore various alternative contractual commitments and financial options, as well as facility modifications, to ensure stable fuel supplies and to mitigate further supply risks for near and long-term coal supplies.

The volatility in fuel oil and natural gas commodity pricing and changes to spark spreads may provide us opportunities to capture short-term market value through strategic purchases of these commodities and sales of power in the spot or forward markets.

The ISO-NE is in the process of restructuring its capacity market and will be transitioning from a fixed payment structure to a forward capacity market structure in 2010. The transitional payments for capacity commenced in December 2006, with a price of $3.05 kW/month, and have risen gradually to $4.10 kW/month through May 31, 2010. The delivery of capacity under the forward capacity market will be fully effective on June 1, 2010. Capacity auctions for the 2010-2011, 2011-2012 and 2012-2013 market periods were held in 2008 and 2009 and resulted in capacity clearing prices of $4.50 kW-month, $3.60 kW-month and $2.95 kW-month respectively. These capacity clearing prices represent the floor price, and the actual rate paid to Casco Bay has been affected by pro-rationing due to oversupply conditions. Discussions to address improvements in the forward capacity market design are currently underway by the ISO and its stakeholders.

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. Further, to the extent that climate change may affect weather patterns, this could result in more extreme weather patterns which could impact demand for our products.

CRITICAL ACCOUNTING POLICIES

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

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments. It is possible that materially different amounts could be recorded if these estimates and judgments change or if actual results differ from these estimates and judgments. We have identified the following six critical accounting policies that require a significant amount of estimation and judgment and are considered 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 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) the sale of both fuel and energy through both physical and financial transactions to optimize the financial performance of our generating facilities; (ii) sale of capacity; and (iii) 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. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative. 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. 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, options, swaps, and other instruments used to mitigate variability in earnings due to fluctuations in market prices. There are 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 statements of operations as the effective portion of the changes in the fair values of the derivative instruments is recognized through equity. Beginning April 2, 2007, we elected to discontinue hedge accounting for our commodity contracts.

Entities may choose whether or not to offset related assets and liabilities and report the net amounts on their consolidated balance sheet if the right of setoff exists. We execute a significant volume of transactions through a futures clearing manager. Our daily cash payments (receipts) to (from) our futures clearing manager consist of three parts: (1) fair value of open positions (exclusive of options) ("Daily Cash Settlements"); (2) initial margin requirements related to open positions (exclusive of options) ("Initial Margin"); and (3) fair value and margin requirements related to options ("Options", and collectively with Initial Margin, "Collateral"). We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement and we elect not to offset the fair value of amounts recognized for the Daily Cash Settlements paid or received against the fair value of 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 the related cash collateral paid or received, on a gross basis.

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. All derivative instruments are recorded at their fair value on the consolidated 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 statements of operations as a portion of the changes in the fair value of the derivative instruments is recognized through equity.

Fair Value Measurements. Fair value 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). 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. The inputs used to measure fair value have been placed in a hierarchy based on priority. 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 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 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. 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.

Valuation of Tangible and Intangible Assets

We evaluate long-lived assets, such as property, plant and equipment and investments for impairment, 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, including an expectation that the asset will be sold;
- 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. If an impairment is indicated, the amount of the impairment loss recognized is determined by the amount the carrying value exceeds the estimated fair value of the assets. For assets identified as held for sale, the carrying value is compared to the estimated sales price less costs to sell. Please read Note 6—Impairment Charges for discussion of impairment charges we recognized in 2009 and 2008.

We review our equity investments by comparing the book value of the investment to the estimated fair value to determine if an impairment is required. We record a loss when the decline in value is considered other than temporary. Please read Note 14—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.

Accounting standards define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. In estimating fair value, we use discounted cash-flow projections, recent comparable market transactions, if available, or quoted prices. We consider assumptions that third parties would make in estimating fair value, including the highest and best use of the asset. There is a significant amount of judgment involved in cash-flow estimates, including assumptions regarding market convergence, discount rates and capacity prices. The assumptions used by another party could differ significantly from our assumptions.

We previously assessed the carrying value of our goodwill annually on November 1 or when circumstances warrant. Step 1 of the goodwill impairment test compares the fair value of a reporting unit to its carrying amount. Step 2 of the goodwill impairment test compares the implied fair value of each reporting unit's goodwill with the carrying amount of such goodwill through a hypothetical purchase price allocation of the fair value of the reporting unit to the reporting unit's tangible and intangible assets. As of March 31, 2009, our goodwill was fully impaired. Please read Note 15—Goodwill for further discussion of our impairment analysis.

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.

During the first quarter 2009, we performed an impairment test of our goodwill due to various events and circumstances. Based on the decline in acquisition activity in recent periods, we were not able to rely fully on recent sales transactions to corroborate our income approach valuation at March 31, 2009. Therefore, we used a market-based approach, comparing our forecasted earnings and Dynegy's market capitalization to those of similarly situated public companies by considering multiples of earnings. There was significant judgment in the selection of companies used for this analysis.

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. 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. 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 disclose and account for various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification 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 21—Commitments and Contingencies for further discussion of our commitments and contingencies.

Accounting for Variable Interest Entities

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 have been an investor in several variable interest entities in which LS Power, 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 concluded that we were not the primary beneficiary of these entities during our ownership period because: (i) we believe that LS Power was more closely associated with the entities; (ii) they owned approximately 40 percent of Dynegy's outstanding common stock during our ownership period; and (iii) they had three seats on Dynegy's Board of Directors. If different judgment were applied, we could have been considered the primary beneficiary of some or all of these entities, which would have significantly impacted our financial condition and results of operations. At December 31, 2009, we are no longer an investor in any variable interest entities with any related parties. Please read Note 14—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 Holding. PPEA Holding 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 Holding and therefore consolidate the entity in our consolidated financial statements. If different judgment were applied, we may not be considered the primary beneficiary of this entity, which would significantly impact our financial condition, results of operations and cash flows.

Please read Note 14—Variable Interest Entities for further discussion of our accounting for our variable interest entities.

Accounting for Income Taxes

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, 2009, could impact deferred tax expense by approximately $33 million for

Dynegy and $23 million for DHI. State statutory tax rates in the states in which we do business range from 1.0 percent to 9.9 percent.

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 reversing temporary differences 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. 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 authoritative guidance on accounting for uncertainty in income taxes, 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 19—Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions 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, 2009. 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 2009. Accordingly, at December 31, 2009, we used a discount rate of 5.86 percent for pension plans and 5.92 percent for other retirement plans, a decrease of 26 and 1 basis points, respectively, from the 6.12 percent for pension plans rate and 5.93 percent for other retirement plans rate used as of December 31, 2008. This decrease in the discount rate increased the underfunded status of the plans by $8 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, 2010 and 2009 was 8.00 percent and 8.25 percent, respectively.

A relatively small difference between actual results and assumptions used by management may have a significant 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, 2009	Impact on 2010 Expense
	(in millions)	
Increase in Discount Rate—50 basis points	$ (15)	$ (2)
Decrease in Discount Rate—50 basis points	16	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 $19 million in cash contributions related to our pension plans during 2010. In addition, we will likely be required to continue to make contributions to the pension plans beyond 2010. Although it is difficult to estimate these potential future cash requirements due to uncertain market conditions, we currently expect that we will contribute approximately $11 million in 2011 and $30 million in 2012.

Please read Note 23—Employee Compensation, Savings and Pension Plans for further discussion of our pension-related assets and liabilities.

RECENT ACCOUNTING PRONOUNCEMENTS

Please read Note 2—Summary of Significant Accounting Policies for further discussion of accounting policies adopted and 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, 2009 (in millions)
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at January 1, 2009	$ (30)
Risk-management gains recognized through the statements of operations in the period, net	282
Cash received related to risk-management contracts settled in the period, net	(451)
Changes in fair value as a result of a change in valuation technique (1)	—
Non-cash adjustments and other (2)	166
Fair value of portfolio at December 31, 2009	$ (33)

(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 as well as ($9) million related to the LS Power Transactions.

The net risk-management liability of $33 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.

Net Fair Value of Risk-Management Portfolio

	Total	2010	2011	2012	2013	2014	Thereafter
				(in millions)			
Market Quotations (1) (2)......	$ (11)	$ 39	$ (50)	$ —	$ —	$ —	$ —
Value Based on Models (2)...	(22)	(21)	(5)	1	1	1	1
Total.......................................	$ (33)	$ 18	$ (55)	$ 1	$ 1	$ 1	$ 1

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

(2) The market quotations and prices based on models categorization differs from the categories of Level 1, Level 2 and Level 3 used in our fair value disclosures due to the application of the different methodologies. Please read Note 7—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. 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 or the IntercontinentalExchange 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. 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 switched methodologies from the JP Morgan RiskMetrics™ approach to a Monte Carlo simulation-based methodology to better estimate risk for non-linear instruments, such as options. We recalculated our daily and average VaR as of December 31, 2008 using the Monte Carlo methodology. The results using the Monte Carlo methodology did not result in a material difference to 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 increase in the December 31, 2009 one day VaR was primarily due to increased forward commodity transactions as compared to December 31, 2008 while the decrease in the December 31, 2009 average annual VaR was primarily due to decreased volatility and lower overall price levels as compared to 2008.

Daily and Average VaR for Mark-to-Market Portfolios

	December 31, 2009	December 31, 2008
	(in millions)	
One day VaR—95 percent confidence level	$ 41	$ 21
One day VaR—99 percent confidence level	$ 57	$ 29
Average VaR for the year-to-date period—95 percent confidence level	$ 34	$ 42

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, 2009 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	$ 40	$ —	$ 40
Utility and power generators	7	3	10
Commercial, industrial and end users	—	8	8
Total	$ 47	$ 11	$ 58

Of the $11 million in credit exposure to non-investment grade counterparties, none is collateralized or subject to other credit exposure protection.

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

We are exposed to fluctuating interest rates related to variable rate financial obligations. As of December 31, 2009, the amount owed under our fixed rate debt instruments, as a percentage of the total amount owed under all of our debt instruments, was 70 percent. Adjusted for interest rate swaps (including the impact of swaps that are not designated as cash flow hedges), net notional fixed rate debt, as a percentage of total debt, was approximately 80 percent. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of December 31, 2009, 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, 2010 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.

The absolute notional financial contract amounts associated with our interest rate contracts were as follows at December 31, 2009 and 2008, respectively:

	December 31, 2009	December 31, 2008
Cash flow hedge interest rate swaps (in millions of U.S. dollars) (1)	$ —	$ 471
Fixed interest rate paid on swaps (percent)	—	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) (1)	$ 784	$ 231
Fixed interest rate paid (percent)	5.33	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) As of July 28, 2009, we determined that PPEA's interest rate swap agreements no longer qualify for cash flow hedge accounting because the hedged forecasted transaction is no longer probable of occurring. Accordingly, the notional values associated with these swaps are included in interest rate risk-management contracts at December 31, 2009. Please read Note—Risk Management Activities, Derivatives and Financial Instrument—Impact of Derivatives on the Consolidated Statements of Operations—Cash Flow Hedges for further discussion.

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, 2009.

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, 2009. 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, 2009.

The effectiveness of Dynegy's internal control over financial reporting as of December 31, 2009 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 SEC 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, 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, 2009, 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, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2009 consolidated financial statements of Dynegy Inc. and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2010

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 2010 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, 2009.

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 2010 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, 2009.

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 2010 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, 2009.

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. We intend to include information regarding ownership of Dynegy's outstanding securities in Dynegy's definitive proxy statement for its 2010 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, 2009.

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 and Director independence in Dynegy's definitive proxy statement for its 2010 annual meeting of stockholders under the headings "Transactions with Related Persons, Promoters and Certain Control Persons", and "Corporate Governance", respectively, 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, 2009.

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 2010 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, 2009.

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 2010 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, 2009.

PART IV

Item 15. *Exhibits and 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	—Dissolution Agreement by and between Dynegy Inc. and LS Power Associates, L.P., effective January 1, 2009.
2.2	—Purchase and Sale Agreement, dated August 9, 2009 (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on August 13, 2009, File No. 001-33443).
2.3	—Amendment No. 1 to Purchase and Sale Agreement, dated as of November 25, 2009 (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 1, 2009, File No. 001-33443).
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. (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 11, 2009, File No. 001-33443).
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	—Fifth Supplemental Indenture dated as of December 1, 2009 between Dynegy Holdings Inc. and Wilmington Trust Company (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on December 1, 2009, File No. 001-33443 and 000-29311, respectively).

Exhibit Number	Description
4.12	—7.5 percent Senior Unsecured Note Due 2015 (included in Exhibit 4.1 and incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on December 1, 2009, File No. 001-33443 and 000-29311, respectively).
4.13	—Sixth Supplemental Indenture dated as of December 30, 2009 between Dynegy Holdings and Wilmington Trust Company (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on January 4, 2010, File No. 001-33443 and 000-29311, respectively).
**4.14	—Note Repurchase Agreement by and between Dynegy Holdings Inc. and the Party Signatory thereto, dated as of December 11, 2009.
4.15	—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).
4.16	—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).
4.17	—Trust Indenture, dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004 of Dynegy Inc, File No. 1-15659).
4.18	—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).
4.19	—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).
4.20	—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).
4.21	—Shareholder Agreement, dated as of August 9, 2009 between Dynegy Inc. and LS Power and its affiliates (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on August 13, 2009, File No. 001-33443.
4.22	—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).
4.23	—Amendment No. 1 to the Registration Rights Agreement dated September 14 2006 by and between Dynegy Inc. and LS Power and affiliates, dated August 9, 2009 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on August 13, 2009, File No. 001-33443)

Exhibit Number	Description
4.24	—Trust Indenture, dated as of April 1, 2006m 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).
4.25	—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).
4.26	—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).
4.27	—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).
4.28	—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).
4.29	—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).
4.30	—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).
4.31	—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).
4.32	Registration Rights Agreement dated as of December 1, 2009 by and between Dynegy Holdings Inc. and Adio Bond, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 1, 2009, File No. 001-33443).
10.1	—Note Purchase Agreement by and between Dynegy Holdings Inc. and Adio Bond, LLC, dated August 9, 2009 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on August 13, 2009, File No. 001-33443).
10.2	—Purchase Agreement, dated as of December 2, 2009, by and among Credit Suisse Securities (USA) and Citigroup Global Markets Inc. (as representatives for additional purchasers named in the Purchase Agreement), Adio Bond, LLC and Dynegy Holdings Inc. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K by Dynegy Inc. filed on December 7, 2009, File No. 001-33443).
10.3	—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 10.2 to the Quarterly Report on Form 10-Q for the Quarter Period ended June 30, 2009 of Dynegy Inc., File No. 001-33443).

Exhibit Number	Description
10.4	—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).
10.5	—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 November 6, 2008, File No. 000-29311).
10.6	—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 (incorporated by reference to Exhibit 10.2 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443).
10.7	—Amendment No. 4, dated as of August 5, 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., as parent guarantor, 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 Inc. filed on August 10, 2009, File No. 000-29311).
10.8	—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).
10.9	—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 (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarter Period ended June 30, 2009 of Dynegy Inc., File No. 001-33443).
10.10	—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 10.9 to the Quarterly Report on Form 10-Q for the Quarter Period ended June 30, 2009 of Dynegy Inc., File No. 001-33443).
10.11	—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 (incorporated by reference to Exhibit 10.2 to the Annual Report on Form 10-K for the year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443).
10.12	—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 Quarterly Report on Form 10-Q for the Quarter Period ended June 30, 2009 of Dynegy Inc., File No. 001-33443).

Exhibit Number	Description
10.13	—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).
10.14	—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). ††
**10.15	—First Amendment to the Dynegy Inc. Executive Severance Pay Plan effective as of January 1, 2010. ††
10.16	—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). ††
10.17	—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). ††
10.18	—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). ††
10.19	—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). ††
10.20	—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). ††
10.21	—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). ††
10.22	—Form of Non-Qualified Stock Option Award Agreement between Dynegy Inc., all of its affiliates and Bruce A. Williamson (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2009 of Dynegy Inc. filed on May 7, 2009, File No. 001-33443). ††
10.23	—Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2009 of Dynegy Inc. filed on May 7, 2009, File No. 001-33443). ††
10.24	—Form of Phantom Stock Unit Award Agreement between Dynegy Inc., all of its affiliates and Bruce A. Williamson (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 10, 2009, File No. 001-33443). ††
10.25	—Form of Phantom Stock Unit Award Agreement (Managing Directors and Above) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on March 10, 2009, File No. 001-33443). ††
10.26	—Form of Performance Award Agreement between Dynegy Inc., all of its affiliates and Bruce A. Williamson (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on March 10, 2009, File No. 001-33443). ††
10.27	—Form of Performance Award Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 10, 2009, File No. 001-33443). ††
10.28	—Dynegy Inc. 2009 Phantom Stock Plan (incorporated by reference to Exhibit 10.3 to the Current Report onForm8-K of Dynegy Inc. filed on March 10, 2009, File No. 001-33443). ††

Exhibit Number	Description
10.29	—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). ††
10.30	—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). ††
10.31	—Dynegy Inc. Deferred Compensation Plan for Certain Directors, as amended and restated, effective January 1, 2008 (incorporated by reference to Exhibit 10.55 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443). ††
10.32	—Trust under Dynegy Inc. Deferred Compensation Plan for Certain Directors, effective January 1, 2009 (incorporated by reference to Exhibit 10.56 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443). ††
10.33	—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). ††
10.34	—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). ††
10.35	—Dynegy Inc. 1999 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156). ††
10.36	—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). ††
10.37	—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). ††
10.38	—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). ††
10.39	—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). ††
10.40	—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). ††
10.41	—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). ††
10.42	—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). ††
10.43	—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). ††

Exhibit Number	Description
10.44	—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). ††
10.45	—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).
10.46	—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).
**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.)
**23.3	—Consent of Ernst & Young 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 25, 2010

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 25, 2010
/s/ HOLLI C. NICHOLS Holli C. Nichols	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2010
/s/ TRACY A. McLAUCHLIN Tracy A. McLauchlin	Senior Vice President and Controller (Principal Accounting Officer)	February 25, 2010
/s/ DAVID W. BIEGLER David W. Biegler	Director	February 25, 2010
/s/ THOMAS D. CLARK, JR. Thomas D. Clark, Jr.	Director	February 25, 2010
/s/ VICTOR E. GRIJALVA Victor E. Grijalva	Director	February 25, 2010
/s/ PATRICIA A. HAMMICK Patricia A. Hammick	Director	February 25, 2010
/s/ GEORGE L. MAZANEC George L. Mazanec	Director	February 25, 2010
/s/ HOWARD B. SHEPPARD Howard B. Sheppard	Director	February 25, 2010
/s/ WILLIAM L. TRUBECK William L. Trubeck	Director	February 25, 2010

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 25, 2010

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 25, 2010
/s/ HOLLI C. NICHOLS Holli C. Nichols	Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	February 25, 2010
/s/ TRACY A. McLAUCHLIN Tracy A. McLauchlin	Senior Vice President and Controller (Principal Accounting Officer)	February 25, 2010
/s/ J. KEVIN BLODGETT J. Kevin Blodgett	Director	February 25, 2010
/s/ LYNN A. LEDNICKY Lynn A. Lednicky	Director	February 25, 2010

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, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedules listed in the Index at Item 15(a). 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, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, 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 Notes 2 and 5 to the consolidated financial statements, effective January 1, 2009 the Company adopted authoritative guidance issued by the Financial Accounting Standards Board for noncontrolling interests.

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, 2009, 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 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2010

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, 2009 and 2008, and the related consolidated statements of operations, cash flows, comprehensive income (loss), and stockholder's equity for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedule listed in the Index at Item 15(a). 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, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, 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 Notes 2 and 5 to the consolidated financial statements, effective January 1, 2009 the Company adopted authoritative guidance issued by the Financial Accounting Standards Board for noncontrolling interests.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2010

DYNEGY INC.
CONSOLIDATED BALANCE SHEETS
(in millions, except share data)

	December 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 471	$ 693
Restricted cash and investments	78	87
Short-term investments	9	25
Accounts receivable, net of allowance for doubtful accounts of $22 and $22, respectively	212	340
Accounts receivable, affiliates	2	1
Inventory	141	184
Assets from risk-management activities	713	1,263
Deferred income taxes	6	6
Broker margin account	286	85
Prepayments and other current assets	120	119
Total Current Assets	2,038	2,803
Property, Plant and Equipment	9,071	10,869
Accumulated depreciation	(1,954)	(1,935)
Property, Plant and Equipment, Net	7,117	8,934
Other Assets		
Unconsolidated investments	—	15
Restricted cash and investments	877	1,158
Assets from risk-management activities	163	114
Goodwill	—	433
Intangible assets	380	437
Accounts receivable, affiliates	—	4
Other long-term assets	378	315
Total Assets	$ 10,953	$ 14,213
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 181	$ 303
Accrued interest	36	56
Accrued liabilities and other current liabilities	127	160
Liabilities from risk-management activities	696	1,119
Notes payable and current portion of long-term debt	807	64
Total Current Liabilities	1,847	1,702
Long-term debt	4,575	5,872
Long-term debt to affiliates	200	200
Long-Term Debt	4,775	6,072
Other Liabilities		
Liabilities from risk-management activities	213	288
Deferred income taxes	780	1,166
Other long-term liabilities	359	500
Total Liabilities	7,974	9,728
Commitments and Contingencies (Note 21)		
Stockholders' Equity		
Class A Common Stock, $0.01 par value, 2,100,000,000 shares authorized at December 31, 2009 and December 31, 2008; 603,577,577 shares and 505,821,277 shares issued and outstanding at December 31, 2009 and December 31, 2008, respectively	6	5
Class B Common Stock, $0.01 par value, 850,000,000 shares authorized at December 31, 2009 and December 31, 2008; 340,000,000 shares issued and outstanding at December 31, 2008.	—	3
Additional paid-in capital	6,056	6,485
Subscriptions receivable	(2)	(2)
Accumulated other comprehensive loss, net of tax	(150)	(215)
Accumulated deficit	(2,937)	(1,690)
Treasury stock, at cost, 2,788,383 shares and 2,568,286 shares at December 31, 2009 and December 31, 2008, respectively	(71)	(71)
Total Dynegy Inc. Stockholders' Equity	2,902	4,515
Noncontrolling interests	77	(30)
Total Stockholders' Equity	2,979	4,485
Total Liabilities and Stockholders' Equity	$ 10,953	$ 14,213

See the notes to the consolidated financial statements

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

	Year Ended December 31,		
	2009	2008	2007
Revenues	$ 2,468	$ 3,324	$ 2,918
Cost of sales	(1,194)	(1,693)	(1,436)
Operating and maintenance expense, exclusive of depreciation shown separately below	(519)	(466)	(440)
Depreciation and amortization expense	(335)	(346)	(306)
Goodwill impairments	(433)	—	—
Impairment and other charges, exclusive of goodwill impairments shown separately above	(538)	—	—
Gain (loss) on sale of assets, net	(124)	82	43
General and administrative expenses	(159)	(157)	(203)
Operating income (loss)	(834)	744	576
Losses from unconsolidated investments	(71)	(123)	(3)
Interest expense	(415)	(427)	(384)
Debt extinguishment costs	(46)	—	—
Other income and expense, net	11	84	56
Income (loss) from continuing operations before income taxes	(1,355)	278	245
Income tax benefit (expense)	315	(90)	(140)
Income (loss) from continuing operations	(1,040)	188	105
Income (loss) from discontinued operations, net of tax benefit (expense) of $121, $14 and $(102), respectively (Note 4)	(222)	(17)	166
Net income (loss)	(1,262)	171	271
Less: Net income (loss) attributable to the noncontrolling interests	(15)	(3)	7
Net income (loss) attributable to Dynegy Inc.	$ (1,247)	$ 174	$ 264
Earnings (Loss) Per Share (Note 20):			
Basic earnings (loss) per share attributable to Dynegy Inc.:			
Earnings (loss) from continuing operations	$ (1.25)	$ 0.23	$ 0.13
Income (loss) from discontinued operations	(0.27)	(0.03)	0.22
Basic earnings (loss) per share attributable to Dynegy Inc.	$ (1.52)	$ 0.20	$ 0.35
Diluted earnings (loss) per share attributable to Dynegy Inc.:			
Earnings (loss) from continuing operations	$ (1.25)	$ 0.23	$ 0.13
Income (loss) from discontinued operations	(0.27)	(0.03)	0.22
Diluted earnings (loss) per share attributable to Dynegy Inc.	$ (1.52)	$ 0.20	$ 0.35
Basic shares outstanding	822	840	752
Diluted shares outstanding	826	842	754

See the notes to the consolidated financial statements

DYNEGY INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31, 2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (1,262)	$ 171	$ 271
Adjustments to reconcile income (loss) to net cash flows from operating activities:			
Depreciation and amortization	359	376	333
Goodwill impairments	433	—	—
Impairment and other charges, exclusive of goodwill impairments shown separately above	796	47	—
Losses from unconsolidated investments, net of cash distributions	72	124	3
Risk-management activities	180	(255)	(50)
Loss (gain) on sale of assets, net	218	(82)	(267)
Deferred taxes	(436)	73	215
Legal and settlement charges	2	6	26
Debt extinguishment costs	46	—	—
Other	82	36	35
Changes in working capital:			
Accounts receivable	66	68	(114)
Inventory	7	3	(13)
Broker margin account	(201)	(50)	(25)
Prepayments and other assets	15	(1)	(12)
Accounts payable and accrued liabilities	(112)	(71)	(15)
Changes in non-current assets	(119)	(113)	(57)
Changes in non-current liabilities	(11)	(13)	11
Net cash provided by operating activities	135	319	341
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(612)	(611)	(379)
Unconsolidated investments	1	(6)	3
Proceeds from asset sales, net	652	451	558
Business acquisitions, net of cash acquired	—	—	(128)
Decrease (increase) in short-term investments	17	(27)	—
Decrease (increase) in restricted cash	190	80	(871)
Other investing, net	3	11	—
Net cash provided by (used in) investing activities	251	(102)	(817)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	328	192	2,758
Repayments of borrowings	(890)	(45)	(2,320)
Debt extinguishment costs	(46)	—	—
Net proceeds from issuance of capital stock	—	2	4
Other financing, net	—	(1)	(9)
Net cash provided by (used in) financing activities	(608)	148	433
Net increase (decrease) in cash and cash equivalents	(222)	365	(43)
Cash and cash equivalents, beginning of period	693	328	371
Cash and cash equivalents, end of period	$ 471	$ 693	$ 328

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 Controlling Interests	Noncontrolling Interests	Total
December 31, 2006	$ 4,373	$ 39	$ (8)	$ 67	$ (2,135)	$ (69)	$ 2,267	$ —	$ 2,267
Net income	—	—	—	—	264	—	264	7	271
Other comprehensive loss, net of tax	—	—	—	(92)	—	—	(92)	(5)	(97)
Adjustment to initially apply FIN No. 48	—	—	—	—	7	—	7	—	7
Subscriptions receivable	—	—	3	—	—	—	3	—	3
Options exercised	1	2	—	—	—	(2)	1	—	1
401(k) plan and profit sharing stock	1	3	—	—	—	—	4	—	4
Options and restricted stock granted	—	19	—	—	—	—	19	—	19
Equity issuance-LS Power (Note 3)	3	2,030	—	—	—	—	2,033	—	2,033
Sale of additional interests in subsidiary (Note 4)	—	—	—	—	—	—	—	43	43
Noncontrolling interest in acquired subsidiary (Note 3)	—	—	—	—	—	—	—	(22)	(22)
Conversion from Illinois entity to Delaware entity (Note 22)	(4,370)	4,370	—	—	—	—	—	—	—
December 31, 2007	$ 8	$ 6,463	$ (5)	$ (25)	$ (1,864)	$ (71)	$ 4,506	$ 23	$ 4,529
Net income (loss)	—	—	—	—	174	—	174	(3)	171
Other comprehensive loss, net of tax	—	—	—	(190)	—	—	(190)	(50)	(240)
Subscriptions receivable	—	—	3	—	—	—	3	—	3
Options exercised	—	2	—	—	—	—	2	—	2
401(k) plan and profit sharing stock	—	5	—	—	—	—	5	—	5
Options and restricted stock granted	—	15	—	—	—	—	15	—	15
December 31, 2008	$ 8	$ 6,485	$ (2)	$ (215)	$ (1,690)	$ (71)	$ 4,515	$ (30)	$ 4,485
Net loss	—	—	—	—	(1,247)	—	(1,247)	(15)	(1,262)
Other comprehensive income, net of tax	—	—	—	65	—	—	65	122	187
401(k) plan and profit sharing stock	—	5	—	—	—	—	5	—	5
Board of directors stock compensation	—	(1)	—	—	—	—	(1)	—	(1)
Retirement of Class B common stock (Note 22)	(2)	(441)	—	—	—	—	(443)	—	(443)
Options and restricted stock granted	—	8	—	—	—	—	8	—	8
December 31, 2009	$ 6	$ 6,056	$ (2)	$ (150)	$ (2,937)	$ (71)	$ 2,902	$ 77	$ 2,979

See the notes to the consolidated financial statements

DYNEGY INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in millions)

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$ (1,262)	$ 171	$ 271
Cash flow hedging activities, net:			
Unrealized mark-to-market gains (losses) arising during period, net	166	(142)	(95)
Reclassification of mark-to-market (gains) losses to earnings, net	1	10	(25)
Deferred losses on cash flow hedges, net	(11)	(4)	—
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $(24), $60 and $69, respectively)	156	(136)	(120)
Foreign currency translation adjustments	—	(27)	4
Actuarial gain (loss) and amortization of unrecognized prior service cost (net of tax benefit (expense) of $(8), $29 and $(9), respectively)	7	(41)	18
Unrealized gain (loss) on securities, net:			
Unrealized gain (loss) on securities	—	(3)	6
Reclassification adjustments for gains realized in net income (loss)	—	(9)	(5)
Unrealized gains (losses) on securities, net (net of tax benefit (expense) of zero, $8, and $(1), respectively)	—	(12)	1
Unconsolidated investment other comprehensive loss, net (net of tax benefit (expense) of $(17) and $17, respectively)	24	(24)	—
Other comprehensive income (loss), net of tax	187	(240)	(97)
Comprehensive income (loss)	(1,075)	(69)	174
Less: Comprehensive income (loss) attributable to the noncontrolling interests	107	(53)	2
Comprehensive income (loss) attributable to Dynegy Inc.	$ (1,182)	$ (16)	$ 172

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.
CONSOLIDATED BALANCE SHEETS
(in millions)

	December 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 419	$ 670
Restricted cash and investments	78	87
Short-term investments	8	24
Accounts receivable, net of allowance for doubtful accounts of $20 and $20, respectively	214	343
Accounts receivable, affiliates	2	1
Inventory	141	184
Assets from risk-management activities	713	1,263
Deferred income taxes	7	4
Broker margin account	286	85
Prepayments and other current assets	120	119
Total Current Assets	1,988	2,780
Property, Plant and Equipment	9,071	10,869
Accumulated depreciation	(1,954)	(1,935)
Property, Plant and Equipment, Net	7,117	8,934
Other Assets		
Restricted cash and investments	877	1,158
Assets from risk-management activities	163	114
Goodwill	—	433
Intangible assets	380	437
Accounts receivable, affiliates	—	4
Other long-term assets	378	314
Total Assets	$ 10,903	$ 14,174
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$ 181	$ 284
Accrued interest	36	56
Accrued liabilities and other current liabilities	128	157
Liabilities from risk-management activities	696	1,119
Notes payable and current portion of long-term debt	807	64
Deferred income taxes	—	1
Total Current Liabilities	1,848	1,681
Long-term debt	4,575	5,872
Long-term debt to affiliates	200	200
Long-Term Debt	4,775	6,072
Other Liabilities		
Liabilities from risk-management activities	213	288
Deferred income taxes	704	1,052
Other long-term liabilities	360	498
Total Liabilities	7,900	9,591
Commitments and Contingencies (Note 21)		
Stockholder's Equity		
Capital Stock, $1 par value, 1,000 shares authorized at December 31, 2009 and December 31, 2008, respectively	—	—
Additional paid-in capital	5,135	5,684
Affiliate receivable	(777)	(827)
Accumulated other comprehensive loss, net of tax	(150)	(215)
Accumulated deficit	(1,282)	(29)
Total Dynegy Holdings Inc. Stockholder's Equity	2,926	4,613
Noncontrolling interests	77	(30)
Total Stockholders' Equity	3,003	4,583
Total Liabilities and Stockholder's Equity	$ 10,903	$ 14,174

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Year Ended December 31, 2009	2008	2007
Revenues	$ 2,468	$ 3,324	$ 2,918
Cost of sales	(1,194)	(1,693)	(1,436)
Operating and maintenance expense, exclusive of depreciation shown separately below	(521)	(466)	(440)
Depreciation and amortization expense	(335)	(346)	(306)
Goodwill impairments	(433)	—	—
Impairment and other charges, exclusive of goodwill impairments shown separately above	(538)	—	—
Gain (loss) on sale of assets	(124)	82	43
General and administrative expenses	(159)	(157)	(184)
Operating income (loss)	(836)	744	595
Earnings (losses) from unconsolidated investments	(72)	(40)	6
Interest expense	(415)	(427)	(384)
Debt extinguishment costs	(46)	—	—
Other income and expense, net	10	83	53
Income (loss) from continuing operations before income taxes	(1,359)	360	270
Income tax benefit (expense)	313	(138)	(105)
Income (loss) from continuing operations	(1,046)	222	165
Income (loss) from discontinued operations, net of tax benefit (expense) of $121, $14 and $(103), respectively (Note 4)	(222)	(17)	166
Net income (loss)	(1,268)	205	331
Less: Net income (loss) attributable to the noncontrolling interests	(15)	(3)	7
Net income (loss) attributable to Dynegy Holdings Inc.	$ (1,253)	$ 208	$ 324

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2009	**2008**	**2007**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (1,268)	$ 205	$ 331
Adjustments to reconcile income (loss) to net cash flows from operating activities:			
Depreciation and amortization	359	376	333
Goodwill impairments	433	—	—
Impairment and other charges, exclusive of goodwill impairments shown separately above	796	47	—
(Earnings) losses from unconsolidated investments, net of cash distributions	73	41	(6)
Risk-management activities	180	(255)	(50)
Gain (loss) on sale of assets, net	218	(82)	(267)
Deferred taxes	(430)	119	179
Legal and settlement charges	2	6	26
Debt extinguishment costs	46	—	—
Other	79	32	32
Changes in working capital:			
Accounts receivable	66	67	(114)
Inventory	7	3	(13)
Broker margin account	(201)	(50)	(25)
Prepayments and other assets	15	(1)	(12)
Accounts payable and accrued liabilities	(93)	(67)	(1)
Changes in non-current assets	(119)	(108)	(56)
Changes in non-current liabilities	(11)	(14)	11
Net cash provided by operating activities	152	319	368
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(612)	(611)	(379)
Proceeds from asset sales, net	1,095	451	558
Unconsolidated investments	—	10	13
Business acquisitions, net of cash acquired	—	—	16
Decrease (increase) in short-term investments	16	(25)	—
Decrease (increase) in restricted cash	190	80	(871)
Affiliate transactions	98	1	(24)
Other investing, net	3	7	(1)
Net cash provided by (used in) investing activities	790	(87)	(688)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	328	192	2,758
Repayments of borrowings	(890)	(45)	(2,045)
Debt extinguishment costs	(46)	—	—
Dividends to affiliates	(585)	—	(342)
Other financing, net	—	(1)	(2)
Net cash provided by (used in) financing activities	(1,193)	146	369
Net increase (decrease) in cash and cash equivalents	(251)	378	49
Cash and cash equivalents, beginning of period	670	292	243
Cash and cash equivalents, end of period	$ 419	$ 670	$ 292

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 Controlling Interests	Noncontrolling Interests	Total
December 31, 2006	$ 3,543	$ —	$ 67	$ (574)	$ 3,036	$ —	$ 3,036
Net income	—	—	—	324	324	7	331
Other comprehensive loss, net of tax	—	—	(92)	—	(92)	(5)	(97)
Adjustment to initially apply FIN No. 48	—	—	—	13	13	—	13
Contribution of Contributed Entities and the Sandy Creek Project to DHI	2,483	—	—	—	2,483	—	2,483
Reclassification of affiliate receivable	—	(825)	—	—	(825)	—	(825)
Sale of additional interests in subsidiary (Note 4)	—	—	—	—	—	43	43
Noncontrolling interest in acquired subsidiary (Note 5)	—	—	—	—	—	(22)	(22)
Dividends to affiliates	(342)	—	—	—	(342)	—	(342)
December 31, 2007	$ 5,684	$ (825)	$ (25)	$ (237)	$ 4,597	$ 23	$ 4,620
Net income (loss)	—	—	—	208	208	(3)	205
Other comprehensive loss, net of tax	—	—	(190)	—	(190)	(50)	(240)
Affiliate activity	—	(2)	—	—	(2)	—	(2)
December 31, 2008	$ 5,684	$ (827)	$ (215)	$ (29)	$ 4,613	$ (30)	$ 4,583
Net loss	—	—	—	(1,253)	(1,253)	(15)	(1,268)
Other comprehensive income, net of tax	—	—	65	—	65	122	187
Affiliate activity (Note 18)	—	50	—	—	50	—	50
Dividends to affiliates (Note 18)	(585)	—	—	—	(585)	—	(585)
Contribution of intangible assets from Dynegy Inc. (Note 18)	36	—	—	—	36	—	36
December 31, 2009	$ 5,135	$ (777)	$ (150)	$ (1,282)	$ 2,926	$ 77	$ 3,003

See the notes to the consolidated financial statements

DYNEGY HOLDINGS INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in millions)

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$ (1,268)	$ 205	$ 331
Cash flow hedging activities, net:			
Unrealized mark-to-market gains (losses) arising during period, net	166	(142)	(95)
Reclassification of mark-to-market (gains) losses to earnings, net	1	10	(25)
Deferred losses on cash flow hedges, net	(11)	(4)	—
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $(24), $60 and $69, respectively)	156	(136)	(120)
Foreign currency translation adjustments	—	(27)	4
Actuarial gain (loss) and amortization of unrecognized prior service cost (net of tax benefit (expense) of $(8), $29 and $(9), respectively)	7	(41)	18
Unrealized gain (loss) on securities, net:			
Unrealized gain (loss) on securities	—	(3)	6
Reclassification adjustments for gains realized in net income (loss)	—	(9)	(5)
Unrealized gains (losses) on securities, net (net of tax benefit (expense) of zero, $8, and $(1), respectively)	—	(12)	1
Unconsolidated investment other comprehensive loss, net (net of tax benefit (expense) of $(17) and $17, respectively)	24	(24)	—
Other comprehensive income (loss), net of tax	187	(240)	(97)
Comprehensive income (loss)	$ (1,081)	$ (35)	$ 234
Less: Comprehensive income (loss) attributable to the noncontrolling interests	107	(53)	2
Comprehensive income (loss) to Dynegy Holdings Inc.	$ (1,188)	$ 18	$ 232

See the notes to the consolidated financial statements

Note 1—Organization and Operations

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 Holding"). PPEA Holding owns Plum Point Energy Associates, LLC ("PPEA") which in turn owns an approximate 57 percent undivided interest in a 665 MW coal-fired power generation facility (the "Plum Point Project") under construction in Arkansas, which is included in GEN-MW.

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 the Plum Point Project. 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 17—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 cannot 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 6—Impairment Charges for a discussion of impairment charges we recognized in 2008 related to Dynegy's investment in DLS Power Holdings.

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 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.

We may opportunistically sell emissions allowances, subject to certain regulatory limitations and restrictions contained in our Midwest 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, 2009, we had aggregate deferred gains of $10 million, which is included in Accrued liabilities and other current liabilities and Other long-term liabilities in our consolidated balance sheets. As of December 31, 2008, we had aggregate deferred gains of $9 million, which is included in Other long-term liabilities in our consolidated balance sheets. We recognized $22 million, $32 million and $13 million in revenue for the years ended December 31, 2009, 2008 and 2007, 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 (loss) on sale of assets, net, in the consolidated statements of operations. We assess the carrying value of our property, plant and equipment to determine if an impairment is indicated when a triggering event occurs. 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 6—Impairment Charges for a discussion of impairment charges we recognized in 2009 and 2008.

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 assess the carrying value of 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, recent market comparable transactions, and earnings multiples of similarly situated public companies. 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. Please read Note 15—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. 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.

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,		
	2009	2008	2007
		(in millions)	
Beginning of year	$ 127	$ 107	$ 56
Accretion expense	13	10	8
Acquisition of the Contributed Entities	—	—	43
Divestiture of assets	(6)	—	—
Revision of previous estimate (1)	(14)	10	—
End of year	$ 120	$ 127	$ 107

(1) We revised our ARO obligation downward by $(14) million in 2009 and upward by $10 million in 2008 based on revised estimates of the cost to dismantle the South Bay facility.

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 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. 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. 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 disclose and account for various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification 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) the sale of both fuel and energy through both physical and financial transactions to optimize the financial performance of our generating facilities; (ii) sale of capacity; and (iii) 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. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative. 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. 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. There are 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 execute a significant volume of transactions through a futures clearing manager. Our daily cash payments (receipts) to (from) our futures clearing manager consist of three parts: (1) fair value of open positions (exclusive of options) ("Daily Cash Settlements"); (2) initial margin requirements related to open positions (exclusive of options) ("Initial Margin"); and (3) fair value and margin requirements related to options ("Options", and collectively with Initial Margin, "Collateral"). We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement and we do not elect to offset the fair value amounts recognized for the Daily Cash Settlements paid or 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 related Daily Cash Settlements, on a gross basis. As of December 31, 2009, of the approximately $286 million included in Broker margin account on our consolidated balance sheets, approximately $288 million represents Collateral, offset by approximately $2 million representing Daily Cash Settlements. As of December 31, 2008, of the approximately $85 million included in Broker margin account on our consolidated balance sheets, approximately $115 million represents Collateral, offset by approximately $30 million representing Daily Cash Settlements.

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 authoritative guidance for financial assets and liabilities measured at fair value on a recurring basis. This authoritative guidance defines fair value, establishes a framework for measuring fair value and expands disclosure requirements for fair value measurements. This framework applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, this authoritative guidance does not require any new fair value measurements; however, for some entities its application will change current practice. The provisions of this authoritative guidance were 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 existing authoritative guidance, (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.

On October 10, 2008, we adopted authoritative guidance which clarifies the application of existing standards for fair value measurement to a financial asset when the market for that financial asset is not active. This authoritative guidance was effective upon issuance by the FASB. The issuance of this authoritative guidance had no impact on our financial statements.

Fair value 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, 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 financial 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. The inputs used to measure fair value have been placed in a hierarchy based on priority.

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 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 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. 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.

On January 1, 2009, we adopted authoritative guidance issued by the FASB for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). In determining fair value for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis, we use discounted cash-flow projections, recent comparable market transactions, if available, or quoted prices. We consider assumptions that third parties would make in estimating fair value, including the highest and best use of the asset. These fair values are categorized in Level 3.

In determining the fair value of our reporting units, we generally use the income approach and utilize market information, such as recent sales transaction for comparable assets within the regions in which we operate to corroborate the fair values derived from the income approach. When there are not sufficient sales transactions to corroborate the income approach valuation, we use a market-based approach. The market-based approach compares our forecasted earnings and Dynegy's market capitalization to those of similarly situated public companies by considering multiples of earnings.

Income Taxes. 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.

We recognize accrued interest expense and penalties related to unrecognized tax benefits as income tax expense.

Please read Note 19—Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions 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 $1 million, $24 million and $(6) million for the years ended December 31, 2009, 2008 and 2007, 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. We use the fair-value based method of accounting for stock-based employee compensation and we used the prospective method of transition for stock options granted. 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 use 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 authoritative guidance for the accounting for tax effects of share-based payment awards. 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 22—Capital Stock for further discussion of our share-based compensation and expense recognized for the years ended December 31, 2009, 2008 and 2007.

Noncontrolling Interests. Noncontrolling interests on the consolidated balance sheets includes third party investments in PPEA Holding. On January 1, 2009, we adopted authoritative guidance issued by the FASB for noncontrolling interests. Please read Note 5—Noncontrolling Interests for further discussion.

Prior to the adoption of this authoritative guidance, we allocated net income and other comprehensive income to noncontrolling interest owners in PPEA Holding 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 noncontrolling interest owners would have caused the noncontrolling interest owners to exceed their obligation to fund such losses, the amounts were reallocated back to us. For the years ended December 31, 2008 and 2007, we absorbed approximately $5 million and $1 million, respectively, of losses related to net income and approximately $99 million and $15 million, respectively, of losses related to other comprehensive income in excess of the minority interest holders' funding commitments.

Accounting Principles Adopted

Business Combinations. On January 1, 2009, we adopted authoritative guidance issued by the Financial Accounting Standards Board ("FASB") on business combinations. The guidance 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 of the financial statements all the information they need to evaluate and understand the nature and financial effect of the business combination. The adoption of this statement had no impact on our financial statements.

Fair Value Measurements. On January 1, 2009, we adopted authoritative guidance issued by the FASB for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Please read Note 8—Fair Value Measurements for further discussion.

Disclosures about Derivative Instruments and Hedging Activities. On January 1, 2009, we adopted authoritative guidance issued by the FASB for the disclosure of derivative instruments and hedging activities. Please read Note 7—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

Subsequent Events. On June 30, 2009, we adopted authoritative guidance, as amended, issued by the FASB which provides guidance on management's assessment of subsequent events.

Accounting Standards Codification. Effective July 1, 2009, we adopted authoritative guidance issued by the FASB which superseded all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification is no longer considered authoritative. The adoption of this authoritative guidance had no impact on our financial condition, results of operations or cash flows.

Third Party Credit Enhancement. On January 1, 2009, we adopted authoritative guidance issued by the FASB which applies to liabilities issued with an inseparable third-party credit enhancement when they are measured or disclosed at fair value on a recurring basis. Please read Note 8—Fair Value Measurements for further discussion.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly. On June 30, 2009, we adopted authoritative guidance issued by the FASB which provides guidance on (i) estimating the fair value of an asset or liability when the volume and level of activity for the asset or liability have significantly decreased and (ii) identifying transactions that are not orderly. The adoption of this authoritative guidance had no impact on our financial statements. Please read Note 8—Fair Value Measurements for further discussion.

Employers' Disclosures about Pensions and Other Postretirement Benefits. On December 31, 2009, we adopted authoritative guidance related to an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. Please read Note 23—Employee Compensation, Savings and Pension Plans for further discussion. The objectives of the disclosures about plan assets in an employer's defined benefit pension or other postretirement plan are to provide users of financial statements with an understanding of: (i) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (ii) the major categories of plan assets; (iii) the inputs and valuation techniques used to measure the fair value of plan assets; (iv) the effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period and (v) significant concentrations of risk within plan assets. The adoption of this authoritative guidance had no impact on our financial condition, results of operations or cash flows.

Accounting Principles Not Yet Adopted

Variable Interest Entities. On June 12, 2009, the FASB issued authoritative guidance which amends the consolidation guidance that applies to variable interest entities. The FASB's objective in issuing this authoritative guidance is to improve financial reporting by enterprises involved with variable interest entities. This authoritative guidance is effective for fiscal years beginning after November 15, 2009. We are currently evaluating the impact of this standard on our consolidated financial statements, including an assessment of whether we have a controlling financial interest in PPEA Holding, for the purpose of determining if we are the primary beneficiary and should continue to consolidate PPEA Holding. If we determine that we do not have a controlling interest in PPEA Holding, we would deconsolidate this entity effective January 1, 2010, and, as a result, if we were to record the cumulative effect of this accounting change effective January 1, 2010, we would expect to record a charge of up to $45 million. We do not expect the implementation of this guidance to have an impact on our accounting for any of the other variable interest entities with which we are involved.

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 Power") and (ii) approved the merger of Merger Sub with and into Dynegy Illinois (together with the Merger Agreement, the "LS Power Merger").

Upon the closing of the LS Power 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 LS Power Merger was converted into the right to receive one share of the Class A common stock of Dynegy, and LS Power transferred to Dynegy all of the interests it owned in entities that own eleven power generation facilities (the "Contributed Entities").

As part of the LS Power Merger transactions, LS Power 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 LS Power Merger, LS Power 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 Power formed DLS Power Development Company, LLC, a Delaware limited liability company ("DLS Power Development"). As a result, LS Power and Dynegy each owned a 50 percent of the membership interests in DLS Power Development. Please read Note 14—Variable Interest Entities—DLS Power Holdings and DLS Power Development for a discussion of the 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 LS Power 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 and (ii) an aggregate $70 million under the Term Loan B. Please read Note 17—Debt—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) increase in financial stability believed to be provided by adding these assets to our portfolio; 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 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. 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
Prepaid 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)
Noncontrolling interests	22
Total liabilities and noncontrolling interests 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. All remaining goodwill balances were fully impaired in 2009. Please read Note 15—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 16—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 LS Power. 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 LS Power Merger, this power tolling agreement was effectively settled, which resulted in a second quarter 2007 gain equal to the fair value of this contract. 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 as if the acquisition had occurred on January 1, 2007:

	Twelve Months Ended December 31, 2007	
	Actual	Pro Forma (Unaudited)
	(in millions)	
Revenue	$ 2,918	$ 3,207
Income before cumulative effect of change in accounting principle	271	223
Net income attributable to Dynegy Inc. common stockholders	264	216
Basic earnings per share before cumulative effect of accounting change	$ 0.35	$ 0.29
Diluted earnings per share before cumulative effect of accounting change	0.35	0.29
Basic earnings per share	0.35	0.29
Diluted earnings per share	0.35	0.29

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 authoritative guidance.

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 LS Power Merger had occurred on January 1, 2007 for the year ended December 31, 2007.

The consummation of the LS Power 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 LS Power 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 LS Power 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 LS Power Merger were included within DHI with the exception of Dynegy's former 50 percent interests in DLS Power Holdings and DLS Power Development, which were directly owned by Dynegy. Please read Note 13—Unconsolidated Investments—DLS Power Development for further discussion.

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, as if the acquisition and subsequent contribution had occurred on January 1, 2007:

	Twelve Months Ended December 31, 2007	
	Actual	Pro Forma (Unaudited)
	(in millions)	
Revenue	$ 2,918	$ 3,207
Net income attributable to Dynegy Holdings Inc.	324	279

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 LS Power Merger had occurred on January 1, 2007 for the twelve months ended December 31, 2007. 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 LS Power Merger in accordance with authoritative guidance.

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.

Note 4—Dispositions, Contract Terminations and Discontinued Operations

Dispositions and Contract Terminations

LS Power Transactions. We consummated our transactions (the "LS Power Transactions") with LS Power in two parts, with the issuance of notes by DHI, on December 1, 2009, and the remainder of the transactions closing on November 30, 2009. At closing, Dynegy and DHI received $936 million and $1,476 million, respectively, in cash, net of closing costs. Of the proceeds, $547 million and $990 million related to the disposition of assets, including our interest in the Sandy Creek project, for Dynegy and DHI, respectively. We also received $175 million from the release of restricted cash on our consolidated balance sheets that was used to support our funding commitment to the Sandy Creek Project and $214 million for the issuance of $235 million notes payable at the close of the transaction. In addition, Dynegy received 245 million shares of Dynegy's Class B common stock from LS Power. In exchange, we sold to LS Power five peaking and three combined-cycle generation assets, as well as our remaining interest in the Sandy Creek Project under construction in Texas, and DHI issued the notes to an affiliate of LS Power. Please read Note 18—Related Party Transactions for further discussion.

The remaining 95 million shares of Dynegy's Class B common stock held by LS Power were converted into the same number of shares of our Dynegy's Class A common stock, representing approximately 15 percent of Dynegy's Class A common stock outstanding.

In connection with the LS Power Transactions, Dynegy and LS Power entered into a new shareholder agreement (the "New Shareholder Agreement"), which, among other things, generally restricts LS Power from increasing its now-reduced ownership for up to 30 months. Additionally, it provides that we will not issue Dynegy's equity securities for our own purposes until the earlier of (i) March 31, 2010 or (ii) the first date following closing of the transaction in which LS Power owns, in aggregate, less than 10 percent of Dynegy's then outstanding Class A common stock. Dynegy and LS Power have also terminated the original shareholder agreement, dated September 14, 2006, which provided LS Power with special approval rights, board representation and certain other rights associated with its former Class B shares.

In connection with our closing of the LS Power Transactions, we recorded pre-tax charges of $312 million in the fourth quarter 2009. These charges include $124 million in Gain (loss) on sale of assets, $104 million in Income (loss) from discontinued operations and $84 million in Losses from unconsolidated investments in our consolidated statements of operations. These losses are primarily the result of changes in the value of the shares received by us, changes in the book values of the assets included in the transaction and changes in working capital items not reimbursed by LS Power.

In connection with the signing of the purchase and sale agreement with LS Power on August 9, 2009, our Arlington Valley and Griffith power generation assets (collectively, the "Arizona power generation facilities") and our Bluegrass power generation facility met the requirements for classification as discontinued operations. Accordingly, the results of operations for these facilities have been reclassified as discontinued operations for all periods presented.

We recorded pre-tax impairment charges of $326 million, inclusive of costs to sell, related to the assets included in the LS Power Transactions that did not meet the criteria for classification as discontinued operations for the year ended December 31, 2009. The charges are included in Impairment and other charges in our consolidated statements of operations. Please read Note 6—Impairment Charges for further discussion of these impairments.

We discontinued depreciation and amortization of property, plant and equipment included in the LS Power Transactions that did not meet the criteria for classification as discontinued operations during the third quarter 2009. Depreciation and amortization expense related to these assets totaled $24 million, $32 million and $27 million in the years ended December 31, 2009, 2008 and 2007, respectively.

Rolling Hills. On July 31, 2008, we completed the sale of the Rolling Hills power generation facility ("Rolling Hills") 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.

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 and $8 million in the years ended December 31, 2008 and 2007, 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, 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 (loss) 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 (loss) 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 Holding 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 Project. Following the transaction, our ownership was reduced to 37 percent interest in PPEA Holding, representing an equivalent of approximately 140 MW. 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 (loss) on sale of assets in our consolidated statements of operations.

Discontinued Operations

Arlington Valley, Griffith and Bluegrass. On November 30, 2009, we completed the sale of our interests in the Arizona power generation facilities and Bluegrass power generation facility as part of the LS Power Transactions, as discussed above.

The Arizona power generation facilities, as well as our Bluegrass facility, met the criteria of held for sale during the third quarter 2009. At that time, we discontinued depreciation and amortization of the Arizona power generation facilities' and Bluegrass' property, plant and equipment. Depreciation and amortization expense related to the Arizona power generation facilities totaled approximately $14 million, $20 million and $13 million for years ended December 31, 2009, 2008 and 2007, respectively. Depreciation and amortization expense related to the Bluegrass facility totaled approximately $1 million for the years ended December 31, 2009, 2008 and 2007, respectively. We recorded an impairment charge of $235 million related to the Arizona power generation facilities during the third quarter 2009. We previously recorded impairment charges of $5 million and $18 million related to the Bluegrass facility during the first and second quarters of 2009, respectively. Please read Note 6— Impairment Charges for further discussion of these impairments. The results of the Arizona power generation facilities' operations are reported in discontinued operations for all periods presented in our GEN-WE segment. The results of Bluegrass' operations are reported in discontinued operations for all periods presented in our GEN-MW segment.

Heard County. On April 30, 2009, we completed the sale of our interest in the Heard County power generation facility for approximately $105 million. We recorded a pre-tax impairment of approximately

$47 million in the year ended December 31, 2008, which was included in Income (loss) from discontinued operations on our consolidated statements of operations. Please read Note 6—Impairment Charges—2008 Impairment Charges for further discussion.

Heard County was classified as held for sale during the first quarter 2009. At that time, we discontinued depreciation and amortization of Heard County's property, plant and equipment. Depreciation and amortization expense related to Heard County totaled approximately less than $1 million, $4 million and $5 million for the years ended December 31, 2009, 2008 and 2007, respectively. We are reporting the results of Heard County's operations in discontinued operations for all periods presented.

Calcasieu. On March 31, 2008, we completed the sale of the Calcasieu power generation facility for approximately $56 million, net of transaction costs.

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 in the years ended December 31, 2008 and 2007.

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 $472 million. We recorded a $224 million gain related to the sale of the asset in 2007. The gain includes the impact of allocating approximately $48 million of goodwill associated with the GEN-WE reporting unit to the CoGen Lyondell power generation facility. During the fourth quarter 2007, we reduced our allocation of goodwill to this transaction by $14 million due to revisions of our purchase price allocation in connection with the Merger. 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.

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 in the year ended December 31, 2007. 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, 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, we recognized approximately $11 million of pre-tax income related to favorable settlements of legacy receivables.

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

	GEN-MW	GEN-WE	CRM	DGC	NGL	Total
			(in millions)			
2009						
Revenues	$ 3	$ 113	$ —	$ —	$ —	$ 116
Loss from operations before taxes(1)	(25)	(224)	—	—	—	(249)
Loss from operations after taxes	(17)	(148)	—	—	—	(165)
Loss on sale before taxes	(22)	(72)	—	—	—	(94)
Loss on sale after taxes	(13)	(44)	—	—	—	(57)
2008						
Revenues	$ 2	$ 223	$ —	$ —	$ —	$ 225
Income (loss) from operations before taxes(2)	(2)	(33)	—	—	4	(31)
Income (loss) from operations after taxes	(1)	(19)	—	—	3	(17)
2007						
Revenues	$ 2	$ 479	$ —	$ —	$ —	$ 481
Income (loss) from operations before taxes	(3)	33	15	(1)	—	44
Income (loss) from operations after taxes	(2)	21	15	—	11	45
Gain on sale before taxes	—	224	—	—	—	224
Gain on sale after taxes	—	121	—	—	—	121

(1) Includes $23 million of impairment charges related to our Bluegrass power generation facility in the GEN-MW segment and $235 million of impairment charges related to our Arizona power generation facilities in the GEN-WE segment.

(2) Includes $47 million of impairment charges related to our Heard power generation facility in the GEN-WE segment.

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

	GEN-MW	GEN-WE	CRM	NGL	Total
			(in millions)		
2009					
Revenues	$ 3	$ 113	$ —	$ —	$ 116
Loss from operations before taxes(1)	(25)	(224)	—	—	(249)
Loss from operations after taxes	(17)	(148)	—	—	(165)
Loss on sale before taxes	(22)	(72)	—	—	(94)
Loss on sale after taxes	(13)	(44)	—	—	(57)
2008					
Revenues	$ 2	$ 223	$ —	$ —	$ 225
Income (loss) from operations before taxes(2)	(2)	(33)	—	4	(31)
Income (loss) from operations after taxes	(1)	(19)	—	3	(17)
2007					
Revenues	$ 2	$ 479	$ —	$ —	$ 481
Income (loss) from operations before taxes	(3)	33	15	—	45
Income (loss) from operations after taxes	(2)	21	15	11	45
Gain on sale before taxes	—	224	—	—	224
Gain on sale after taxes	—	121	—	—	121

(1) Includes $23 million of impairment charges related to our Bluegrass power generation facility in the GEN-MW segment and $235 million of impairment charges related to our Arizona power generation facilities in the GEN-WE segment.

(2) Includes $47 million of impairment charges related to our Heard power generation facility in the GEN-WE segment.

Note 5—Noncontrolling Interests

On January 1, 2009, we adopted authoritative guidance which requires: (i) ownership interests in subsidiaries held by parties other than the parent to be clearly identified, labeled, and presented in the consolidated statements of financial position within equity, but separate from the parent's equity; (ii) the amount of consolidated net income (loss) attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statements of operations; (iii) changes in a parent's ownership interests that do not result in deconsolidation to be accounted for as equity transactions; and (iv) that a parent recognize a gain or loss in net income upon deconsolidation of a subsidiary, with any retained noncontrolling equity investment in the former subsidiary initially measured at fair value. This authoritative guidance also requires retrospective application of all disclosure requirements. Accordingly, our consolidated balance sheets as of December 31, 2009 and 2008 and the related consolidated statements of operations, cash flows, comprehensive income and stockholders' equity for the years ended December 31, 2009, 2008 and 2007 reflect the change in presentation for the noncontrolling interests in PPEA Holding. The following table presents the net income (loss) attributable to Dynegy's and DHI's stockholders:

	Dynegy Inc. Twelve Months Ended December 31,			Dynegy Holdings Inc. Twelve Months Ended December 31,		
	2009	2008	2007	2009	2008	2007
	(in millions)					
Income (loss) from continuing operations	$ (1,025)	$ 191	$ 98	$ (1,031)	$ 225	$ 158
Income (loss) from discontinued operations, net of tax benefit (expense) of $121, $14, ($102), $121, $14 and ($103) respectively	(222)	(17)	166	(222)	(17)	166
Net income (loss)	$ (1,247)	$ 174	$ 264	$ (1,253)	$ 208	$ 324

The following table presents a reconciliation of the carrying amount of total equity, equity attributable to Dynegy and the equity attributable to the noncontrolling interests at the beginning and the end of the twelve months ended December 31, 2009:

	Controlling Interest	Noncontrolling Interests	Total
		(in millions)	
December 31, 2008	$ 4,515	$ (30)	$ 4,485
Net loss	(1,247)	(15)	(1,262)
Other comprehensive income (loss), net of tax:			
Unrealized mark-to-market gains arising during period	38	128	166
Reclassification of mark-to-market (gains) losses to earnings	(1)	2	1
Deferred losses on cash flow hedges	(3)	(8)	(11)
Amortization of unrecognized prior service cost and actuarial gain	7	—	7
Unconsolidated investments other comprehensive income	24	—	24
Total other comprehensive income, net of tax	65	122	187
Other equity activity:			
Options and restricted stock granted	8	—	8
401(k) plan and profit sharing stock	5	—	5
Board of Directors stock compensation	(1)	—	(1)
Retirement of Class B common stock	(443)	—	(443)
December 31, 2009	$ 2,902	$ 77	$ 2,979

The following table presents a reconciliation of the carrying amount of total equity, equity attributable to Dynegy and the equity attributable to the noncontrolling interests at the beginning and the end of the twelve months ended December 31, 2008:

	Controlling Interest	Noncontrolling Interests	Total
		(in millions)	
December 31, 2007	$ 4,506	$ 23	$ 4,529
Net income (loss)	174	(3)	171
Other comprehensive loss, net of tax:			
Unrealized mark-to-market losses arising during period	(95)	(47)	(142)
Reclassification of mark-to-market (gains) losses to earnings	11	(1)	10
Deferred losses on cash flow hedges	(2)	(2)	(4)
Foreign currency translation adjustment	(27)	—	(27)
Amortization of unrecognized prior service cost and actuarial loss	(41)	—	(41)
Unconsolidated investments other comprehensive loss	(24)	—	(24)
Unrealized loss on securities, net	(12)	—	(12)
Total other comprehensive loss, net of tax	(190)	(50)	(240)
Other equity activity:			
Options exercised	2	—	2
Options and restricted stock granted	15	—	15
401(k) plan and profit sharing stock	5	—	5
Subscriptions receivable	3	—	3
December 31, 2008	$ 4,515	$ (30)	$ 4,485

The following table presents a reconciliation of the carrying amount of total equity, equity attributable to Dynegy and the equity attributable to the noncontrolling interests at the beginning and the end of the twelve months ended December 31, 2007:

	Controlling Interest	Noncontrolling Interests	Total
		(in millions)	
December 31, 2006	$ 2,267	$ —	$ 2,267
Net income	264	7	271
Other comprehensive loss, net of tax:			
Unrealized mark-to-market losses arising during period	(90)	(5)	(95)
Reclassification of mark-to-market gains to earnings	(25)	—	(25)
Foreign currency translation adjustment	4	—	4
Amortization of unrecognized prior service cost and actuarial gain	18	—	18
Unrealized gain on securities, net	1	—	1
Total other comprehensive loss, net of tax	(92)	(5)	(97)
Other equity activity:			
Options exercised	1	—	1
Options and restricted stock granted	19	—	19
401(k) plan and profit sharing stock	4	—	4
Adjustment to initially apply FIN No. 48	7	—	7
Equity issuance-LS Power	2,033	—	2,033
Sale of additional interests in subsidiary	—	43	43
Noncontrolling interest in acquired subsidiary	—	(22)	(22)
Subscriptions receivable	3	—	3
December 31, 2007	$ 4,506	$ 23	$ 4,529

The following table presents a reconciliation of the carrying amount of total equity, equity attributable to DHI and the equity attributable to the noncontrolling interests at the beginning and the end of the of the twelve months ended December 31, 2009.

	Controlling Interest	Noncontrolling Interests	Total
		(in millions)	
December 31, 2008	$ 4,613	$ (30)	$ 4,583
Net loss	(1,253)	(15)	(1,268)
Other comprehensive income (loss), net of tax:			
Unrealized mark-to-market gains arising during period	38	128	166
Reclassification of mark-to-market (gains) losses to earnings	(1)	2	1
Deferred losses on cash flow hedges	(3)	(8)	(11)
Amortization of unrecognized prior service cost and actuarial gain	7	—	7
Unconsolidated investments other comprehensive income	24	—	24
Total other comprehensive income, net of tax	65	122	187
Other equity activity:			
Affiliate activity	50	—	50
Dividend to Dynegy Inc.	(585)	—	(585)
Contribution from Dynegy Inc.	36	—	36
December 31, 2009	$ 2,926	$ 77	$ 3,003

The following table presents a reconciliation of the carrying amount of total equity, equity attributable to DHI and the equity attributable to the noncontrolling interests at the beginning and the end of the of the twelve months ended December 31, 2008.

	Controlling Interest	Noncontrolling Interests	Total
		(in millions)	
December 31, 2007	$ 4,597	$ 23	$ 4,620
Net income (loss)	208	(3)	205
Other comprehensive loss, net of tax:			
Unrealized mark-to-market losses arising during period	(95)	(47)	(142)
Reclassification of mark-to-market (gains) losses to earnings	11	(1)	10
Deferred losses on cash flow hedges	(2)	(2)	(4)
Foreign currency translation adjustment	(27)	—	(27)
Amortization of unrecognized prior service cost and actuarial loss	(41)	—	(41)
Unconsolidated investments other comprehensive loss	(24)	—	(24)
Unrealized loss on securities, net	(12)	—	(12)
Total other comprehensive loss, net of tax	(190)	(50)	(240)
Other equity activity:			
Affiliate activity	(2)	—	(2)
December 31, 2008	$ 4,613	$ (30)	$ 4,583

The following table presents a reconciliation of the carrying amount of total equity, equity attributable to DHI and the equity attributable to the noncontrolling interests at the beginning and the end of the of the twelve months ended December 31, 2007.

	Controlling Interest	Noncontrolling Interests	Total
		(in millions)	
December 31, 2006	$ 3,036	$ —	$ 3,036
Net income	324	7	331
Other comprehensive loss, net of tax:			
Unrealized mark-to-market gains arising during period	(90)	(5)	(95)
Reclassification of mark-to-market gains to earnings	(25)	—	(25)
Foreign currency translation adjustment	4	—	4
Amortization of unrecognized prior service cost and actuarial gain	18	—	18
Unrealized gain on securities, net	1	—	1
Total other comprehensive loss, net of tax	(92)	(5)	(97)
Other equity activity:			
Contribution of contributed entities and the Sandy Creek Project to DHI	2,483	—	2,483
Adjustment to initially apply FIN No. 48	13	—	13
Reclassification of affiliate receivable	(825)	—	(825)
Sale of additional interests in subsidiary	—	43	43
Noncontrolling interest in acquired subsidiary	—	(22)	(22)
Dividends to affiliates	(342)	—	(342)
December 31, 2007	$ 4,597	$ 23	$ 4,620

Note 6—Impairment Charges

2009 Impairment Charges

The following summarizes pre-tax impairment charges recorded during 2009 which are included in Impairment and other charges in our consolidated statements of operations:

	GEN-MW	GEN-WE	GEN-NE	Total
		(in millions)		
Three months ended June 30, 2009:				
Assets included in the LS Power Transactions	$ —	$ —	$ (179)	$ (179)
Roseton and Danskammer	—	—	(208)	(208)
Total 2nd Quarter Impairment Charges	—	—	(387)	(387)
Three months ended September 30, 2009:				
Assets included in the LS Power Transactions (1)	(147)	—	—	(147)
Roseton and Danskammer	—	—	(1)	(1)
Total 3rd Quarter Impairment Charges	(147)	—	(1)	(148)
Three months ended December 31, 2009:				
Roseton and Danskammer	—	—	(3)	(3)
Total 4th Quarter Impairment Charges	—	—	(3)	(3)
Impairment Charges for the Twelve Months Ended December 31, 2009	$ (147)	$ —	$ (391)	$ (538)

(1) Upon classification of these assets as held for sale at August 9, 2009, we recognized impairment charges of $196 million and $19 million in our GEN-MW and GEN-NE segments, respectively. At September 30, 2009, based on an increase in the fair value of the consideration to be received, we recovered $49 million and $19 million of the impairment charges in our GEN-MW and GEN-NE segments, respectively.

The following summarizes pre-tax impairment charges recorded during 2009 which are included in Income (loss) from discontinued operations in our consolidated statements of operations:

	GEN-MW	GEN-WE	GEN-NE	Total
		(in millions)		
Three months ended March 31, 2009:				
Bluegrass (included in the LS Power Transactions)	$ (5)	$ —	$ —	$ (5)
Total 1st Quarter Impairment Charges	(5)	—	—	(5)
Three months ended June 30, 2009:				
Assets included in the LS Power Transactions	(18)	—	—	(18)
Total 2nd Quarter Impairment Charges	(18)	—	—	(18)
Three months ended September 30, 2009:				
Assets included in the LS Power Transactions (1)	—	(235)	—	(235)
Total 3rd Quarter Impairment Charges	—	(235)	—	(235)
Impairment Charges for the Twelve Months Ended December 31, 2009	$ (23)	$ (235)	$ —	$ (258)

(1) Upon classification of these assets as held for sale at August 9, 2009, we recognized an impairment charge of $292 million and $4 million in our GEN-WE and GEN-MW segments, respectively. At September 30, 2009, based on an increase in the fair value of the consideration to be received, we recovered $57 million and $4 million of the impairment charges in our GEN-WE and GEN-MW segments, respectively.

Bluegrass Impairment. During the first quarter 2009, we performed a goodwill impairment test due to changes in market conditions that would more likely than not reduce the fair values of our GEN-MW, GEN-WE and GEN-NE reporting units below their carrying amounts. Please read Note 15—Goodwill for further discussion. This decline in value also triggered testing of the recoverability of our long-lived assets. We performed an impairment analysis and recorded a pre-tax impairment charge of $5 million ($3 million after tax). This charge, which related to the Bluegrass power generation facility, is included in Income (loss) on discontinued operations in our consolidated statements of operations. We determined the fair value of the Bluegrass facility using assumptions that reflected our best estimate of third party market participants' considerations.

Assets Included in the LS Power Transactions. At June 30, 2009, in connection with discussions leading to the agreement with LS Power discussed further in Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions, we determined it was more likely than not that certain assets would be sold prior to the end of their previously estimated useful lives. Therefore, we updated our March 31, 2009 long-lived asset impairment analysis for each of the asset groups that we were considering for sale as part of the proposed transaction as of June 30, 2009. As a result, we recorded a pre-tax impairment charge of $197 million ($120 million after-tax). Of this charge, $179 million related to the Bridgeport power generation facility and related assets and is included in Impairment and other charges in our consolidated statements of operations in the GEN-NE segment. The remaining $18 million ($11 million after-tax) related to the Bluegrass power generation facility and related assets and is included in Income (loss) from discontinued operations in our consolidated statements of operations in the GEN-MW segment. This additional impairment charge for the Bluegrass power generation facility reflected updated assumptions regarding the terms of a potential sale as well as continued weakening of forward capacity prices in the second quarter 2009. We determined the fair value of these generation facilities and related assets using assumptions that reflect our best estimate of third party market participants' considerations and corroborated these estimates indirectly based on our assumptions regarding the terms of and the overall value inherent in the LS Power Transactions.

In performing the June 30, 2009 impairment analysis, we used an 80 percent likelihood at June 30, 2009 of reaching an agreement for sale of the assets, and certain assumptions about the terms of such a sale. Upon reaching the agreement with LS Power discussed further in Note 4—Dispositions, Contract

Terminations and Discontinued Operations—Dispositions—LS Power Transactions, the assets qualified as held for sale, and additional impairment charges were recorded, as discussed below.

On August 9, 2009, we entered into the purchase and sale agreement with LS Power. At that time, the operating assets included in that agreement met the criteria of held for sale. Accordingly, we updated our impairment analysis reflecting the estimated fair value for the consideration to be received from LS Power inclusive of costs to sell. As a result, we recognized pre-tax impairment charges of $147 million and $235 million in our GEN-MW and GEN-WE segments, respectively, for the three month period ended September 30, 2009. The $147 million charge is included in Impairment and other charges in our consolidated statements of operations. The $235 million charge is included in Income (loss) on discontinued operations in our consolidated statements of operations.

At September 30, 2009, the fair value of the consideration was based partially upon the closing stock price of Dynegy's Class A common stock of $2.55 per share. We recorded additional losses on the sale of these assets upon close of the transaction in the fourth quarter 2009, based on changes subsequent to September 30, 2009 in the fair value of the shares to be received as part of the consideration for this transaction, changes in the fair value of debt to be issued, and changes in working capital items not reimbursed by the purchaser. In addition, we recorded a loss of $84 million on the sale of our Sandy Creek project investment included in this transaction. Please refer to Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion.

Roseton and Danskammer. In updating our impairment analysis for assets that were being considered for sale as discussed above, we noted that the aggregate carrying value of the assets included in the proposed transaction exceeded the aggregate fair value of the consideration to be received. In addition, we noted a continued weakening in forward capacity and forward power prices in certain of the markets in which we operate. This indicated a possible decline in the value of power generation assets in all three of our reportable segments. Therefore, at June 30, 2009, we updated our March 31, 2009 impairment analysis for our remaining power generation facilities not currently under consideration for sale. As a result of changes in market conditions in the second quarter 2009 within the Northeast region, we recorded a pre-tax impairment charge of $208 million ($129 million after-tax) related to the Roseton and Danskammer power generation facilities. This charge is included in Impairment and other charges in our consolidated statements of operations. We determined the fair value of these facilities using assumptions that reflect our best estimate of third party market participants' considerations. This involved using the present value technique, incorporating our best estimate of third party market participants' assumptions about the best use of assets, future power and fuel costs and the costs of complying with environmental regulations. Based on a continuation of expected cash flow losses for these assets in 2009, we recorded additional pre-tax impairment charges of $1 million ($1 million after-tax) for the three months ended September 30, 2009 and $3 million ($2 million after-tax) for the three months ended December 31, 2009.

Other. At September 30, 2009, we assessed the carrying amount of our PPEA long-term assets for impairment because we believed it was more likely than not that we would sell our interest in PPEA Holding before the end of its useful life. In performing this analysis, we used a 50 percent likelihood of a sales transaction occurring in the fourth quarter 2009, and a 50 percent likelihood of our continuing to own the asset while seeking a buyer, and we concluded that an impairment is not indicated. We have no further obligation to provide any financial or other support to PPEA Holding and its wholly-owned subsidiary, PPEA, beyond the $15 million letter of credit we have posted to support our contingent equity contribution (as distinct from financial or other support provided by the holders of the remaining interests in PPEA Holding). As a result, we would not be obligated to either (i) sell the assets at a price below an amount that would settle the liabilities associated with PPEA after considering the equity commitments of PPEA Holding's owners, or (ii) own and operate it at a loss that would require us to contribute more than $15 million.

At December 31, 2009, PPEA determined that it likely will not be able to comply with certain requirements of the PPEA Credit Agreement Facility during 2010. As this debt would be callable in the event of such non-compliance, the lender could pursue various actions, including negotiating with PPEA to restructure the debt. As a result, PPEA may be required to restructure the debt, which would have an impact on the overall value of our interest in PPEA Holding. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion of PPEA's obligations. Therefore, at December 31, 2009, we updated our impairment analysis of the PPEA assets. In performing this analysis, we made certain assumptions around the likelihood PPEA would continue to operate under its current financing structure, restructure its existing financing, or whether the project would become insolvent. We also made certain assumptions about the value of the PPEA's approximate 57 percent interest in the Plum Point Project with its current financing structure and the terms of any potential restructuring. As a result of our analysis, we concluded that an impairment is not indicated; however, if the outcome of any negotiations between PPEA and its lenders is substantially different from our assumptions, we could be required to record an impairment in 2010. Further, if we were to complete a sale of our interest in PPEA Holding in the near term, we would expect to recognize a loss on the sale, as we would recognize through the statement of operations losses associated with PPEA's interest rate swaps that are currently deferred in Accumulated other comprehensive loss.

Our impairment analysis of our generating assets is based on forward-looking projections of our estimated future cash flows based on discrete financial forecasts developed by management for planning purposes. These projections incorporate certain assumptions including forward power and capacity prices, forward fuel costs and costs of complying with environmental regulations. As additional information becomes available regarding the significant assumptions used in our analysis, we may conclude that it is necessary to update our impairment analyses in future periods to assess the recoverability of our assets and additional impairment charges could be required.

2008 Impairment Charges

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. 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 Income (loss) from discontinued operations 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 13—Unconsolidated Investments for further discussion.

Note 7—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 1 to 3 year 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. 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.

Quantitative Disclosures Related to Financial Instruments and Derivatives

On January 1, 2009, we adopted authoritative guidance which 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.

The following disclosures and tables present information concerning the impact of derivative instruments on our consolidated balance sheets and statements of operations. In the table below, commodity contracts primarily consist of derivative contracts related to our power generation business that we have not designated as accounting hedges, that are entered into for purposes of economically hedging future fuel requirements and sales commitments and securing commodity prices. Interest rate contracts primarily consist of derivative contracts related to managing our interest rate risk. As of December 31, 2009, our commodity derivatives were comprised of both long and short positions; a long position is a contract to purchase a commodity, while a short position is a contract to sell a commodity. As of December 31, 2009, we had net long/(short) commodity derivative contracts outstanding and notional interest rate swaps outstanding in the following quantities:

Contract Type	Hedge Designation	Quantity (in millions)	Unit of Measure	Net Fair Value (in millions)
Commodity derivative contracts:				
Electric energy (1)	Not designated	(95)	MW	$ 89
Natural gas (1)	Not designated	160	MMBtu	$ (95)
Electricity/natural gas spread options	Not designated	(7)/56	MW/MMBtu	$ 16
Other (2)	Not designated	1	Misc.	$ 7
Interest rate contracts:				
Interest rate swaps	Fair value hedge	(25)	Dollars	$ 2
Interest rate swaps	Not designated	553	Dollars	$ (50)
Interest rate swaps	Not designated	231	Dollars	$ (15)
Interest rate swaps	Not designated	(206)	Dollars	$ 13

(1) Mainly comprised of swaps, options and physical forwards.

(2) Comprised of emissions, coal, crude oil, fuel oil options, swaps and physical forwards.

Derivatives on the Balance Sheet. The following table presents the fair value and balance sheet classification of derivatives in the consolidated balance sheet as of December 31, 2009, segregated between designated, qualifying hedging instruments and those that are not, and by type of contract segregated by assets and liabilities. 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 that allow an entity to offset the fair value amounts recognized for the Daily Cash Settlements paid or 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 related Daily Cash Settlements, on a gross basis.

Contract Type	Balance Sheet Location	December 31, 2009	December 31, 2008
		(in millions)	
Derivatives designated as hedging instruments:			
Derivative Assets:			
Interest rate contracts	Assets from risk management activities	$ 2	$ 3
Derivative Liabilities:			
Interest rate contracts	Liabilities from risk management activities	—	(238)
Total derivatives designated as hedging instruments, net		2	(235)
Derivatives not designated as hedging instruments:			
Derivative Assets:			
Commodity contracts	Assets from risk management activities	861	1,355
Interest rate contracts	Assets from risk management activities	13	19
Derivative Liabilities:			
Commodity contracts	Liabilities from risk management activities	(844)	(1,147)
Interest rate contracts	Liabilities from risk management activities	(65)	(22)
Total derivatives not designated as hedging instruments, net		(35)	205
Total derivatives, net		$ (33)	$ (30)

Impact of Derivatives on the Consolidated Statements of Operations

The following discussion and tables present the disclosure of the location and amount of gains and losses on derivative instruments in our consolidated statements of operations for the twelve months ended December 31, 2009, 2008 and 2007 segregated between designated, qualifying hedging instruments and those that are not, by type of contract.

Cash Flow Hedges. We may 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.

In the second quarter 2007, one of our consolidated subsidiaries, PPEA, entered into three interest rate swap agreements with an initial aggregate notional amount of approximately $184 million. These interest rate swap agreements convert certain of PPEA's floating rate debt exposure to a fixed interest rate of approximately 5.3 percent. The aggregate notional amount of the swaps at December 31, 2009 was approximately $553 million. These interest rate swap agreements expire in June 2040. Effective July 1, 2007, we designated these agreements as cash flow hedges. Therefore, the effective portion of the changes in value after that date (and prior to July 28, 2009, as further discussed below) are reflected in other comprehensive income (loss), and subsequently reclassified to interest expense contemporaneously with the related accruals of interest expense, or depreciation expense in the event the interest was capitalized.

The PPEA interest rate swap agreements are unconditionally and irrevocably guaranteed by Ambac Assurance Corporation ("Ambac"). On July 28, 2009, Ambac's credit rating was downgraded. As a result of the Ambac downgrade, on October 16, 2009, PPEA's credit rating was also downgraded. Based on PPEA's downgrade, the interest rate swap agreements can now be terminated at Ambac's discretion, which would result in an obligation by PPEA to pay the termination value. Ambac has the ability to control the termination of these swaps at its sole discretion under the applicable agreements; therefore, the associated risk management liability has been classified as current at December 31, 2009. However, Ambac has given no indication that it intends to cause the swaps to be terminated. In fact, if it were to do so, it would trigger its own obligation as insurer to pay the termination value to the swap counterparties, as PPEA does not have the resources to do so. In addition, Ambac can also consent to a request by any of the counterparties to terminate the interest rate swaps, which would result in a payment obligation by

PPEA for the termination value. However, should PPEA fail to pay the termination value, Ambac would only be required to pay the scheduled quarterly settlements. Failure to pay the termination value could result in the potential acceleration of PPEA's debt. Please read Note 14—Variable Interest Entities—PPEA Holding Company LLC for further discussion of our obligations to PPEA.

Based on the events described above, as of July 28, 2009, we determined the interest rate swap agreements no longer qualify for cash flow hedge accounting because the hedged forecasted transaction (that is, the future interest payments arising from the PPEA Credit Agreement Facility) is no longer probable of occurring. We performed a final effectiveness test as of July 28, 2009 and no ineffectiveness was recorded. The amounts previously deferred in Accumulated other comprehensive income (loss) were not reclassified into earnings because, although the likelihood of the forecasted transaction is not high enough to be considered probable of occurring, it is also not low enough that we would consider it probable that the future interest payments associated with the underlying debt will not occur. The change in value of the interest rate swap agreements from July 28, 2009 through December 31, 2009 was a loss of less than $1 million, and is included in Interest expense on our consolidated statement of operations. As a result of discontinuing hedge accounting for the interest rate swaps, all prospective changes in the fair value and associated settlements of these interest rate swaps will impact earnings. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion.

During the twelve month periods ended December 31, 2009, 2008 and 2007, we recorded zero, $2 million and $9 million, respectively, related to ineffectiveness from changes in fair value of derivative positions and 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, 2009, 2008 and 2007, no amounts were reclassified to earnings in connection with forecasted transactions that were considered probable of not occurring.

The $72 million balance in cash flow hedging activities within Accumulated other comprehensive income (loss), net at December 31, 2009 is expected to be reclassified to future earnings when the forecasted hedged transaction impacts earnings. Because a significant majority of the interest expense incurred by PPEA is capitalized, a significant portion of the derivative settlements prior to the dedesignation discussed above are deferred in Accumulated other comprehensive income (loss) and will be reclassified to depreciation expense over the expected life of the plant once the Plum Point Project commences operations. Because not all of the interest expense is capitalized, 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, 2010. The actual amounts that will be reclassified to earnings over this period and beyond could vary materially from this estimated amount as a result of changes in the probability of the forecasted transactions not occurring.

The PPEA interest rate swap agreements contain provisions that require PPEA's debt to maintain an investment grade credit rating from a major credit rating agency. As PPEA's debt has fallen below investment grade, the counterparties to the three interest rate swap agreements could request immediate payment or demand collateralization on instruments in net liability positions if Ambac, as guarantor, were to declare bankruptcy. However, absent an Ambac bankruptcy, PPEA is under no obligation to post collateral or terminate the swaps. A default on PPEA's obligations pursuant to the interest rate swap agreements would cause PPEA to also be in default of the terms of its project debt. Our obligations related to our investment in PPEA are limited to our $15 million letter of credit issued under our Credit Facility to support our contingent equity contribution to the Plum Point Project. Please read Note 17—Debt—Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) for further discussion.

The impact of interest rate swap contracts designated as cash flow hedges and the related hedged item on our consolidated statements of operations and other comprehensive income (loss) for the twelve months ended December 31, 2009, 2008 and 2007 is presented below:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) For the Twelve Months Ended December 31, 2009	2008	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) For the Twelve Months Ended December 31, 2009	2008
	(in millions)			(in millions)	
Interest rate contracts	$ 166	$ (142)	Interest expense	$ (4)	$ (2)
Commodity contracts (1)	—	—	Revenues	—	(19)
Total	$ 166	$ (142)		$ (4)	$ (21)

(1) Beginning April 2, 2007, we chose to cease designating derivatives related to our power generation business as hedges. These amounts represent reclassifications into earnings of amounts that were previously frozen in Accumulated other comprehensive loss upon de-designation in April 2007.

Fair Value Hedges. We also enter into derivative instruments that qualify, and that we may elect to 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. The maximum length of time for which we have hedged our exposure for fair value hedges is through 2011. During the twelve month periods ended December 31, 2009, 2008 and 2007, 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, 2009, 2008 and 2007, there were no gains or losses related to the recognition of firm commitments that no longer qualified as fair value hedges.

The impact of interest rate swap contracts designated as fair value hedges and the related hedged item on our consolidated statements of operations for the twelve months ended December 31, 2009 and 2008 was immaterial.

Financial Instruments Not Designated as Hedges. We elect not to designate derivatives related to our power generation business and certain interest rate instruments as cash flow or fair value hedges. Thus, we account for changes in the fair value of these derivatives within the consolidated statements of operations (herein referred to as "mark-to-market accounting treatment"). As a result, these mark-to-market gains and losses are not reflected in the consolidated statements of operations in the same period as the underlying activity for which the derivative instruments serve as economic hedges.

For the twelve months ended December 31, 2009, our revenues included approximately $180 million of mark-to-market losses related to this activity compared to $252 million of mark-to-market gains and $44 million of mark-to-market losses in the periods ended December 31, 2008 and 2007, respectively.

The impact of derivative financial instruments that have not been designated as hedges on our consolidated statements of operations for the twelve month periods ended December 31, 2009 and 2008 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we expect to realize when the underlying physical transactions settle.

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of All Gain (Loss) Recognized in Income on Derivatives for the Twelve Months Ended December 31, 2009	2008
		(in millions)	
Commodity contracts	Revenues	$ 337	$ 264
Interest rate contracts	Interest expense	(12)	(2)

Note 8—Fair Value Measurements

The following tables set 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, 2009 and 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, 2009			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Assets from commodity risk management activities	$ —	$ 780	$ 81	$ 861
Assets from interest rate swaps	—	15	—	15
Other—DHI (1)	—	8	—	8
Total—DHI	—	803	81	884
Other—Dynegy (1)	—	1	—	1
Total—Dynegy	$ —	$ 804	$ 81	$ 885
Liabilities:				
Liabilities from commodity risk management activities	$ —	$ (791)	$ (53)	$ (844)
Liabilities from interest rate swaps	—	(15)	(50)	(65)
Total	$ —	$ (806)	$ (103)	$ (909)

(1) Other represents short-term investments.

	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	$ —	$ (1,394)	$ (13)	$ (1,407)

(1) Other represents short-term investments.

The following tables set 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, 2009
	(in millions)
Balance at December 31, 2008	$ 60
Realized and unrealized gains, net	47
Purchases, issuances and settlements	(79)
Transfers to Level 3	(50)
Balance at December 31, 2009	$ (22)
Change in unrealized gains, net, relating to instruments still held as of December 31, 2009	$ 3

	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. As of December 31, 2009, PPEA held interest rate swaps with a contractual net liability of approximately $80 million. The fair value of these liabilities is estimated to be approximately $50 million as it reflects a valuation adjustment for the deterioration of PPEA's credit worthiness pursuant to fair value accounting standards. As a result of the significance of the credit valuation adjustment, these interest rate swaps are now reflected in Level 3.

On January 1, 2009, we adopted authoritative guidance, which applies to liabilities issued with an inseparable third-party credit enhancement when they are measured or disclosed at fair value on a recurring basis. The underlying principle is that a third-party credit enhancement does not relieve the issuer of its ultimate obligation under the liability. We had approximately $286 million of Collateral as of December 31, 2009 included in Broker margin account on our consolidated balance sheets. Substantially all of our derivative positions with our derivative counterparties are supported by letters of credit issued pursuant to our Credit Facility (as defined below) or by cash collateral postings. As a result, we no longer can consider the letters of credit as credit enhancements in our valuation of our derivative liabilities beginning in 2009. Our adoption of this authoritative guidance did not result in a material effect on our consolidated financial statements for the twelve months ended December 31, 2009.

On January 1, 2009, we adopted authoritative guidance for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis, which had been deferred under existing authoritative guidance. The following table sets forth by level within the fair value hierarchy our fair value measurements with respect to nonfinancial assets and liabilities that are measured at fair value on a nonrecurring basis as of December 31, 2009. These 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 Measurements as of December 31, 2009				
	Level 1	Level 2	Level 3 (in millions)	Total	Total Losses
Assets/Liabilities:					
Goodwill	$ —	$ —	$ —	$ —	$ (433)
Assets and liabilities associated with assets related to the LS Power Transactions	—	—	—	—	(584)
Assets held and used	—	—	—	—	(212)
Total	$ —	$ —	$ —	$ —	$ (1,229)

During the first quarter 2009, goodwill with a carrying amount of $433 million was written down to its implied fair value of zero, resulting in an impairment charge of $433 million, which is included in Goodwill impairment on our consolidated statements of operations. Please read Note 15—Goodwill for further discussion and disclosures addressing the description of the inputs and information used to develop the inputs as well as the valuation techniques used to measure the goodwill impairment.

During 2009, long-lived assets held and used were written down to their fair value of zero, resulting in an impairment charge of $212 million, which is included in Impairment and other charges on our consolidated statements of operations. In addition, during the twelve months ended December 31, 2009, net assets/liabilities related to the LS Power Transactions were written down to their fair value of $1,258 million, less costs to sell of $25 million, resulting in an impairment charge of $584 million at September 30, 2009. Of this amount, $326 million is included in Impairment and other charges and $258 million is included in Income (loss) on discontinued operations on our consolidated statements of operations. Please read Note 6—Impairment Charges for further discussion.

Fair Value of Financial Instruments. On June 30, 2009, we adopted authoritative guidance, which requires the disclosure of the estimated 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 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 17—Debt.

	December 31, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Interest rate derivatives designated as cash flow accounting hedges (1)	$ —	$ —	$ (238)	$ (238)
Interest rate derivatives designated as fair value accounting hedges (1)	2	2	3	3
Interest rate derivatives not designated as accounting hedges (1)	(52)	(52)	(2)	(2)
Commodity-based derivative contracts not designated as accounting hedges (1)	17	17	207	207
Other (2)	9	9	25	25
Total	$ (24)	$ (24)	$ (5)	$ (5)

(1) Included in both current and non-current assets and liabilities on the consolidated balance sheets.
(2) Other represents short-term investments.

Concentration of Credit Risk. We sell our energy products and services to customers in the electric and natural gas distribution industries, financial institutions and to entities engaged in industrial 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, 2009, our credit exposure as it relates to the mark-to-market portion of our risk management portfolio totaled $58 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, 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.

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 Broker margin account and Prepayments and other current 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 9—Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, 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, 2009	2008
	(in millions)	
Cash flow hedging activities, net	$ (24)	$ (180)
Unrecognized prior service cost and actuarial loss	(59)	(66)
Accumulated other comprehensive loss—unconsolidated investments	—	(24)
Accumulated other comprehensive loss, net of tax	$ (83)	$ (270)
Less: Accumulated other comprehensive income (loss) attributable to the noncontrolling interests	67	(55)
Accumulated other comprehensive income (loss) attributable to Dynegy Inc, net of tax.	$ (150)	$ (215)

Note 10—Cash Flow Information

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

	Year Ended December 31, 2009	2008	2007
		(in millions)	
Interest paid (net of amount capitalized)	$ 400	$ 413	$ 393
Taxes paid, net	$ 4	$ 23	$ 48
Detail of businesses acquired:			
Current assets and other	$ —	$ —	$ 174
Fair value of non-current assets	—	—	5,122
Liabilities assumed, including deferred taxes	—	—	(2,766)
Non-cash consideration (1)	—	—	(2,378)
Cash balance acquired	—	—	(16)
Cash paid, net of cash acquired (2)	$ —	$ —	$ 136
Other non-cash investing and financing activity:			
Non-cash capital expenditures (3)	$ 32	$ 57	$ 13
Non-cash capital stock acquisition (4)	443	—	—

(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) These expenditures related primarily to our interest in the Plum Point Project and capital expenditures related to the Midwest Consent Decree. Please read Note 14—Variable Interest Entities—PPEA Holding Company LLC for further discussion of our interest in the Plum Point Project and Note 21—Commitment and Contingencies for further discussion of the Midwest Consent Decree.

(4) Represents the reacquisition of 245 million shares of Dynegy's Class B common stock valued at $1.81 per share. Please read Note 4—Dispositions Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion.

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

	Year Ended December 31, 2009	2008 (in millions)	2007
Interest paid (net of amount capitalized)	$ 400	$ 413	$ 393
Taxes paid, net	$ 2	$ 18	$ 35
Detail of businesses acquired:			
Current assets and other	$ —	$ —	$ —
Fair value of non-current assets	—	—	—
Liabilities assumed, including deferred taxes	—	—	—
Cash balance acquired	—	—	—
Cash paid, net of cash acquired	$ —	$ —	$ —
Other non-cash investing and financing activity:			
Non-cash capital expenditures (1)	$ 32	$ 57	$ 13
Contribution of the Contributed Entities from Dynegy to DHI (2)	—	—	2,467
Contribution of Sithe from Dynegy to DHI (3)	—	—	—
Contribution of the Sandy Creek Project from Dynegy to DHI (4)	—	—	16
Contribution of intangible asset from Dynegy to DHI (5)	36	—	—
Other affiliate activity with Dynegy (6)	(48)	—	—

(1) These expenditures related primarily to our interest in the Plum Point Project and capital expenditures related to the Midwest Consent Decree. Please read Note 14—Variable Interest Entities—PPEA Holding Company LLC for further discussion of our interest in the Plum Point Project and Note 21—Commitment and Contingencies for further discussion of the Midwest 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 and as such, the investment was transferred at historical cost. Please read Note 14—Variable Interest Entities—Sandy Creek Project for further information.

(5) In January 2009, Dynegy contributed to DHI its interest in certain intangible assets which Dynegy received upon the dissolution of DLS Power Holdings and DLS Power Development. This contribution was accounted for as a transaction between entities under common control and as such, the intangible was transferred at historical cost. Please read Note 16—Intangible Assets—LS Power for further information.

(6) Represents transactions with Dynegy in the normal course of business, primarily the reallocation of deferred taxes between legal entities in accordance with applicable IRS regulations.

Please read Note 18—Related Party Transactions for a discussion of the change in DHI's affiliate receivable.

Note 11—Inventory

A summary of our inventories is as follows:

	December 31, 2009	December 31, 2008
	(in millions)	
Materials and supplies	$ 61	$ 76
Coal	52	57
Fuel oil	23	29
Emissions allowances	5	18
Natural gas storage	—	4
	$ 141	$ 184

During the twelve months ended December 31, 2009, we recorded lower of cost or market adjustments of $18 million. These charges are included in Cost of sales on our consolidated statements of operations. The lower of cost or market adjustments we recorded for the twelve months ended December 31, 2008 and 2007, were immaterial.

Note 12—Property, Plant and Equipment

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

	December 31, 2009	December 31, 2008
	(in millions)	
Generation assets:		
GEN–MW	$ 6,334	$ 6,825
GEN–WE	1,505	2,390
GEN–NE	1,111	1,501
IT systems and other	121	153
	9,071	10,869
Accumulated depreciation	(1,954)	(1,935)
	$ 7,117	$ 8,934

Interest capitalized related to costs of construction projects in process totaled $24 million, $23 million and $15 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Note 13—Unconsolidated Investments

Equity Method Investments. 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 previously consisted 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, 2009	December 31, 2008
	(in millions)	
Equity affiliates:		
Sandy Creek Services	$ —	$ —
Sandy Creek Holdings LLC (1)	—	(75)
Black Mountain	—	—
Total unconsolidated investments—DHI	—	(75)
DLS Power Holdings and DLS Power Development	—	15
Total unconsolidated investments—Dynegy	$ —	$ (60)

(1) Included in Other long-term liabilities on the consolidated balance sheet as of December 31, 2008.

Cash distributions received from our equity investments during 2009, 2008 and 2007 were $2 million, $16 million, and $10 million, respectively. Undistributed earnings from our equity investments included in accumulated deficit at December 31, 2009 and 2008 totaled zero and $101 million, respectively.

Black Mountain. We hold 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, 2009, 2008 and 2007, we recorded impairment charges of zero, $1 million and $7 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.

Sandy Creek Project. On November 30, 2009 , we sold our interests in SCH and SC Services to LS Power. We recorded a loss of $84 million on the sale. The loss on the sale is partially offset by equity earnings of $12 million for the year ended December 31, 2009. Please read Note 4—Dispositions Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion.

DLS Power Development. Dynegy previously held 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. Under the terms of the dissolution, Dynegy acquired exclusive rights, ownership and developmental control of substantially all repowering or expansion opportunities related to its existing portfolio of operating assets. In the first quarter 2009, Dynegy subsequently contributed these assets to DHI. LS Power received approximately $19 million in cash from Dynegy on January 2, 2009, and acquired full ownership and developmental rights associated with various "greenfield" power generation and transmission development projects not related to Dynegy's existing operating portfolio of assets. Please read Note 14—Variable Interest Entities—DLS Power Holdings and DLS Power Development for further information.

Summarized Information. Summarized aggregate financial information for our previous unconsolidated equity investments in SCH and Sandy Creek Services and its equity share thereof was:

	December 31,					
	2009		2008		2007	
	Total	Equity Share	Total	Equity Share	Total	Equity Share
			(in millions)			
Current assets	$ —	$ —	$ 10	$ 5	$ 7	$ 3
Non-current assets	—	—	384	192	262	131
Current liabilities	—	—	36	18	14	7
Non-current liabilities	—	—	536	268	280	140
Revenues	2	1	2	1	1	—
Operating income	1	—	38	19	27	13
Net income (loss)	15	7	(79)	(40)	17	8

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

	December 31,					
	2009		2008		2007	
	Total	Equity Share	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	2	1	(23)	(12)	(19)	(9)
Net income (loss)	2	1	(23)	(12)	(19)	(9)

Dynegy's Losses from unconsolidated investments of $71 million for the year ended December 31, 2009, include $73 million from SCH offset by income of $1 million from Sandy Creek Services and income of $1 million from DLS Power Holdings. In addition to the $7 million noted above, Dynegy's losses of $73 million from its investment in SCH include a $84 million loss on sale of unconsolidated investment offset by the elimination of $4 million in commitment fees payable to Dynegy that was expensed by SCH. The loss on the sale includes the recognition of $40 million of losses on interest rate swaps that were previously deferred in OCI. Please read Note 14—Variable Interest Entities for further discussion.

Dynegy's Losses from unconsolidated investments of $123 million for the year ended December 31, 2008 include $41 million from SCH and $83 million from DLS Power Holdings offset by income of $1 million from Sandy Creek Services. 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 14—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 14—Variable Interest Entities for further discussion.

DHI's Losses from unconsolidated investments of $72 million for the year ended December 31, 2009 include $73 million from SCH offset by income of $1 million from Sandy Creek Services. In addition to the $7 million noted above, DHI's losses of $73 million from its investment in SCH include a

\$84 million loss on sale of unconsolidated investment offset by the elimination of \$4 million in commitment fees payable to Dynegy that was expensed by SCH. The loss on the sale includes the recognition of \$40 million of losses on interest rate swaps that were previously deferred in OCI. Please read Note 14—Variable Interest Entities for further discussion.

DHI's Losses from unconsolidated investments of \$40 million for the year ended December 31, 2008, include \$41 million from SCH offset by income of \$1 million from Sandy Creek Services. Please read Note 14—Variable Interest Entities for further discussion.

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 14—Variable Interest Entities for further discussion.

Available-for-Sale Securities. As of December 31, 2009, Dynegy and DHI had approximately \$9 million and \$8 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 a result, we 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 were distributed from the Fund in January 2010.

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 consolidated statements of other comprehensive income.

Note 14—Variable Interest Entities

Hydroelectric Generation Facilities. On January 31, 2005, Dynegy completed the acquisition of ExRes, the parent company of Sithe Energies, Inc. 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 owned through its subsidiaries four hydroelectric generation facilities 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, or otherwise dispose of the hydroelectric facilities owned through the VIEs. Exelon is obligated to reimburse us for all costs, liabilities, and obligations of the entities owning these hydroelectric generation facilities, and to indemnify us 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.

During December 2009, we sold two of these facilities to a third party as directed by Exelon. We do not consolidate these entities, and we did not record a gain or loss upon completion of the transaction.

The hydroelectric generation facilities have commitments and obligations arising under operating leases for equipment and long-term power purchase agreements with local utilities that are off-balance sheet with respect to us. At December 31, 2009, the equipment leases have remaining terms from eleven to twenty-one years, including options to extend two of the leases and involve future lease payments of $132 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. The remaining two 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, 2009 was approximately $352 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 remaining two 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 Holding, which represented an ownership interest of approximately 70 percent. PPEA Holding owns PPEA. PPEA is constructing the Plum Point Project, 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 PPEA 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.

At the acquisition date and continuing after the sale, we have determined that we are the primary beneficiary of PPEA Holding 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 and the other third party ownership interests are reflected in non-controlling interests.

PPEA is the borrower under a $700 million term loan facility, a $17 million revolving credit facility, and a $102 million letter of credit facility securing $100 million of tax exempt bonds. The credit facilities are secured by a security interest in all of PPEA's assets, contract rights and PPEA's undivided tenancy in common interest in the Plum Point Project and PPEA Holding's interest in PPEA. There are no guarantees of the indebtedness by any parties, and PPEA's creditors have no recourse against our general credit. Please read Note 17—Debt—Plum Point (Including Plum Point Credit Agreement Facility and Plum Point Tax Exempt Bonds) for discussion of Plum Point's borrowings.

As of December 31, 2009, we have posted $15 million in letters of credit to support our contingent equity contribution to PPEA, and the other investors have also posted $31 million letters of credit to support their contingent equity contributions to PPEA. Other than providing services under the Project

Management Agreement and the Operations and Maintenance Agreements which was terminated on April 30, 2009, we have not provided any other financial or other support to PPEA.

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

	December 31, 2009	December 31, 2008
	(in millions)	
As of:		
Current assets	$ 6	$ 1
Property, plant and equipment, net	611	507
Intangible asset	190	193
Other non-current asset	20	29
Total assets	827	730
Current portion of long-term debt	744	—
Current liabilities	74	19
Long-term debt	—	615
Non-current liabilities	—	244
Noncontrolling interest	77	(30)
Accumulated other comprehensive loss	(157)	(215)
For the period ending:		
Operating loss	(1)	(1)
Net loss	(7)	(3)

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 the LS Power Merger, Dynegy acquired a 50 percent interest in DLS Power Holdings and DLS Power Development. These entities were dissolved effective January 1, 2009. 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. DLS Power Holdings and DLS Power Development met the definition of VIEs, as they required additional subordinated financial support from their owners to conduct normal on-going operations. Dynegy determined that it was not the primary beneficiary of the entities because LS Power, a related party, was more closely associated with the entities as they were the managing partner of the entities, owned approximately 40 percent of Dynegy's outstanding common stock and had three seats on Dynegy's Board of Directors. Therefore, Dynegy did not consolidate the entities.

Prior to dissolution of the entities, Dynegy accounted for its investments in DLS Power Holdings and DLS Power Development as equity method investments. 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 Power 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 Power 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 approximately $19 million in cash in consideration for the dissolution.

Sandy Creek Project. 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, an indirectly wholly owned subsidiary of Dynegy, and LSP Sandy Creek Member, LLC each owned 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 owned 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.

On November 30, 2009 , we completed our previously announced agreement to sell our interests in SCH and SC Services to LS Power. We recorded a loss of $84 million on the sale of these investments in the fourth quarter of 2009. Please read Note 4—Dispositions Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion.

Note 15—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. We review goodwill for potential impairment as of November 1st of each year or more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. During the first quarter 2009, there were several events and circumstances which, when considered in the aggregate, indicated such a reduction in the fair value of our GEN-MW, GEN-WE and GEN-NE reporting units:

- The first quarter 2009 was characterized by a steep decline in forward commodity prices. Forward market prices for natural gas decreased by 27 percent and 17 percent, respectively, for the calendar years 2009 and 2010, significantly impacting the current market and corresponding forward market prices for power;
- During the first quarter 2009, acquisition activity related to power generation facilities was very low, indicating a lack of demand for such transactions;
- Dynegy's market capitalization continued to decline through the first quarter 2009, with Dynegy's stock price falling from an average of $2.51 per share in the fourth quarter 2008 to an average of $1.73 per share in the first quarter 2009 and a closing price of $1.41 at March 31, 2009; and

- General economic indicators, such as economic growth forecasts and unemployment forecasts, deteriorated further during the first quarter 2009.

Considered individually, none of the foregoing events and circumstances would necessarily indicate a significant reduction in the fair value of our reporting units. However, in light of the significant drop in forward power prices during the first quarter 2009 and the further deterioration in general economic indicators, it was deemed unlikely that Dynegy's market capitalization would exceed its book equity in the near future. As a result, we concluded that an impairment test of our goodwill on our GEN-MW, GEN-WE and GEN-NE reporting units was required as of March 31, 2009.

The impairment test is performed in two steps at the reporting unit level. The first step compares the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of the reporting unit is higher than its carrying amount, no impairment of goodwill is indicated and no further testing is required. However, if the fair value of the reporting unit is below its carrying amount, a second step must be performed to determine the goodwill impairment required, if any.

Consistent with historical practice, on November 1, 2008, we determined the fair value of our reporting units using the income approach based on a discounted cash flows model. This approach used 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. In performing our impairment test at November 1, 2008, the results of our fair value assessment using the income approach were corroborated using market information about recent sales transactions for comparable assets within the regions in which we operate.

Due to further declines in our market capitalization through December 31, 2008, we determined that 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.

As a result of the events and circumstances discussed above, as of March 31, 2009, we updated our fair value assessment using the income approach, taking into account the significant drop in forward prices we observed over the three months ended March 31, 2009. As our long-term outlook on power demand remained unchanged, we did not change our expectations regarding commodity prices beyond 2011 for purposes of this analysis. Additionally, we updated the weighted average cost of capital assumptions used in our income approach to reflect current market data as of March 31, 2009.

Based on the decline in acquisition activity during the first quarter 2009 and the length of time from the most recent asset sales transactions we used to corroborate the results of our income approach valuation in November 2008, we were not able to rely fully on recent sales transactions to corroborate the results of our fair value assessment using the income approach in March 2009. Therefore, for our first quarter 2009 analysis, we also used a market-based approach, comparing our forecasted earnings and Dynegy's market capitalization to those of similarly situated public companies by considering multiples of earnings.

For each of the reporting units included in our analysis, fair value assessed using the income approach exceeded the fair value assessed using this market-based approach. However, given that Dynegy's market capitalization had continued to remain below its book equity for more than nine months and given the absence of recent asset sales transaction activity to reasonably corroborate the results of our income approach valuation, we determined that there had been a shift in the manner in which market participants were valuing our business, and believed that the market-based approach had become more relevant for estimating the fair value of our reporting units as of March 31, 2009. We therefore concluded that it was appropriate to place equal weight on the market-based approach (rather than relying primarily on the income approach) for the purpose of determining fair value in step one of the impairment analysis. Based on the results of our analysis discussed above, our GEN-MW, GEN-WE and GEN-NE reporting units did not pass the first step as of March 31, 2009.

Having determined that the carrying values of the GEN-MW, GEN-WE and GEN-NE reporting units exceeded their fair values, we performed the second step of the analysis. This second step compared the implied fair value of each reporting unit's goodwill with the carrying amount of such goodwill. We performed a hypothetical allocation of the fair value of the reporting units determined in step one to all of the assets and liabilities of the unit, including any unrecognized intangible assets. After making these hypothetical allocations, we determined no residual value remained that could be allocated to goodwill within each of our GEN-MW, GEN-WE or GEN-NE segments. We recorded first quarter 2009 impairment charges on all three of these reporting units, as follows:

Changes in the carrying amount of goodwill during the years ended December 31, 2009, 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
Impairment of goodwill	(76)	(260)	(97)	(433)
December 31, 2009	$ —	$ —	$ —	$ —

Note 16—Intangible Assets

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

	LS Power	Sithe	Rocky Road	Total
		(in millions)		
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
Additions (1)	15	—	—	15
Impairments (2)	(5)	—	—	(5)
LS Power Transactions (3)	(5)	—	—	(5)
Amortization expense	(11)	(49)	(4)	(64)
December 31, 2009	$ 203	$ 235	$ —	$ 438

(1) Represents certain intangible assets we retained upon the dissolution of DLS Power Holdings and DLS Power Development partnerships. Please read Note 14—Variable Interest Entities—DLS Power Holdings and DLS Power Development for further discussion of the dissolution.
(2) Represents the impairment of an intangible asset at our Bridgeport power generation facility.
(3) Represents the sale of certain intangibles to LS Power in November 2009. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion of the LS Power Transactions.

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 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 the third quarter of 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 in Revenue 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 $10 million, $7 million, $7 million, $7 million and $7 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 Revenue in 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 Revenue in our consolidated statements of operations where we record the revenues received from the contract. This asset was fully amortized in 2009.

Note 17—Debt

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

	December 31,			
	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Term Loan B, due 2013	$ 68	$ 66	$ 69	$ 52
Term Facility, floating rate due 2013	850	814	850	639
Senior Notes and Debentures:				
6.875 percent due 2011	81	82	502	427
8.75 percent due 2012	89	92	501	426
7.5 percent due 2015 (1)	785	737	550	388
8.375 percent due 2016	1,047	998	1,047	742
7.125 percent due 2018	172	140	173	110
7.75 percent due 2019	1,100	950	1,100	762
7.625 percent due 2026	171	119	172	93
Subordinated Debentures payable to affiliates, 8.316 percent, due 2027.	200	107	200	83
Sithe Senior Notes, 9.0 percent due 2013	287	294	344	328
PPEA Credit Agreement Facility, floating rate due 2010	644	334	515	365
PPEA Tax Exempt Bonds, floating rate due 2036	100	100	100	100
	5,594		6,123	
Unamortized premium (discount) on debt, net	(12)		13	
	5,582		6,136	
Less: Amounts due within one year, including non-cash amortization of basis adjustments (2)	807		64	
Total Long-Term Debt	$ 4,775		$ 6,072	

(1) Includes the issuance of $235 million aggregate principal amount to Adio Bond, LLC on December 1, 2009. Please read "—Senior Notes and Debentures" below for further discussion.
(2) Includes $744 million of PPEA's non-recourse project financing.

Aggregate maturities of the principal amounts of all long-term indebtedness as of December 31, 2009 are as follows: 2011—$150 million, 2012—$164 million, 2013—$1,006 million, 2014—zero and thereafter—$3,455 million.

Credit Facility (Including Term Loan B and Term Facility)

On April 2, 2007, we entered into a fifth amended and restated credit facility (the "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.

On May 24, 2007, September 30, 2008, February 13, 2009 and August 5, 2009, we entered into amendments to the Credit Facility. The discussion below reflects the impact of all such amendments.

The Credit Facility, as amended, currently consists of a $1.08 billion revolving credit facility (the "Revolving Facility"), an $850 million term letter of credit facility (the "Term L/C Facility") and 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.

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, 2007, with the unpaid balance due at maturity.

The Credit Facility, as amended, 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 Credit Facility, as amended, and certain other obligations to the lenders thereunder and their affiliates are secured by substantially all of the assets of such guarantors.

Interest Costs. Borrowings under the Credit Facility, as amended, 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 Credit Facility, as amended, depends on the Standard & Poor's Ratings Services ("S&P") and Moody's Investors Service, Inc. ("Moody's") credit ratings of the Credit Facility, as amended, with higher credit ratings resulting in a lower rate. The applicable margin for such borrowings will be either 2.375 percent or 2.75 percent per annum for base rate loans and either 3.375 percent or 3.75 percent per annum for Eurodollar loans, with the lower applicable margin being payable if the ratings for the Credit Facility, as amended, 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 0.625 percent or 0.75 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.

Prepayment Provisions. The Credit Facility, as amended, contains mandatory prepayment provisions associated with specified asset sales and dispositions (including as a result of casualty or condemnation). However, we may designate up to $500 million of net proceeds from the sale of assets after August 5, 2009, as excluded from the asset sale, reinvestment and prepayment provisions of the Credit Facility, as amended.

Covenants and Events of Default. The Credit Facility, as amended, 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 debt prepayment covenants were amended to provide that, in the event the maturity date of any of the 6.875 percent Senior Notes due 2011 or the 8.75 percent Senior Notes due 2012 issued by DHI is extended to a date, or refinanced with debt maturing, after April 2, 2013, DHI may prepay other longer-dated indebtedness in the amount of any such notes so extended or refinanced.

The Credit Facility, as amended, 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 a specified amount; 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 of no less than a specified amount. The following table summarizes the required ratios:

Period Ended:	(i) Secured Debt : Adjusted EBITDA No greater than:	(ii) Adjusted EBITDA : Interest Expense No less than:
December 31, 2009	3.00 : 1	1.75 : 1
March 31, 2010	3.25 : 1	1.70 : 1
June 30, 2010	3.25 : 1	1.60 : 1
September 30, 2010	3.50 : 1	1.30 : 1
December 31, 2010	3.50 : 1	1.30 : 1
March 31, 2011	3.50 : 1	1.35 : 1
June 30, 2011	3.50 : 1	1.40 : 1
September 30, 2011	3.25 : 1	1.60 : 1
December 31, 2011	3.00 : 1	1.60 : 1
Thereafter	2.50 : 1	1.75 : 1

Additionally, prior to incurring certain DHI indebtedness, adding revolver commitments, making certain investments or certain sales of assets or engaging in certain other permitted activities, we must satisfy certain conditions precedent, including satisfaction, on a pro forma basis, of a separate ratio test of Total Indebtedness to Adjusted EBITDA (as defined in the Credit Facility, as amended).

Period Ended:	Total Debt : Adjusted EBITDA No greater than:
December 31, 2009	6.00 : 1
March 31, 2010	6.50 : 1
June 30, 2010	6.50 : 1
September 30, 2010	6.50 : 1
December 31, 2010	6.50 : 1
March 31, 2011	6.50 : 1
June 30, 2011	6.50 : 1
September 30, 2011	6.25 : 1
December 31, 2011	6.00 : 1
Thereafter	5.00 : 1

We are in compliance with these covenants as of December 31, 2009.

Senior Notes and Debentures

In general, DHI's Senior 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. They are not redeemable at DHI's option prior to maturity. Dynegy did not guarantee the Senior Notes, and the assets that Dynegy owns do not support the Senior Notes. 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.

On December 1, 2009, as part of the LS Power Transactions, DHI issued to Adio Bond, LLC ("Adio Bond"), an affiliate of LS Power, $235 million aggregate principal amount of its 7.5 percent Senior Unsecured Notes due 2015 (the "Notes") for $214 million in proceeds. The terms and conditions of the Notes are substantially the same as the comparable series of 7.5 percent Senior Secured Notes due 2015 previously issued. The difference of $21 million between the face value and the fair value that was recognized upon issuance will be accreted into interest expense over the life of the debt.

In connection with the closing of the LS Power Transactions, DHI entered into a registration rights agreement with Adio Bond pursuant to which DHI has agreed to offer to exchange the Notes for a new issue of substantially identical notes registered under the Securities Act of 1933. Under the terms of the registration rights agreement, DHI has agreed to file an exchange offer registration statement with the SEC by August 27, 2010. The interest rates on the Notes will increase at an annual rate of 0.25 percent for each 90-day period during which a failure to register the new Notes continues, up to a maximum increase of 1.0 percent in the annual interest rates.

On December 31, 2009, we completed a cash tender offer and consent solicitation, in which we purchased $421 million of DHI's $500 million 6.875 percent Senior Unsecured Notes due 2011 (the "2011 Notes") and $412 million of DHI's $500 million 8.75 percent Senior Unsecured Notes due 2012 (the "2012 Notes). Total cash paid to repurchase the 2011 Notes and the 2012 Notes, including consent fees, was $879 million. We recorded a pre-tax charge of approximately $47 million associated with this transaction, of which $46 million is included in Debt extinguishment costs, and $1 million of acceleration of amortization of financing costs is included in Interest expense on our consolidated statements of operations.

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, 2009 and 2008, the redemption amount associated with these securities totaled $200 million.

Sithe Senior Notes

The senior debt is secured by substantially all of the assets of Independence, but is not guaranteed by us. The premium balance of $13 million at December 31, 2009 is being 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 and DHI, 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.

Plum Point (Including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds)

PPEA Credit Agreement Facility. The PPEA Credit Agreement Facility (the "PPEA 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 PPEA Credit Agreement Facility bear interest, at PPEA'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, PPEA pays commitment fees equal to 0.125 percent per annum on the undrawn Construction 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 guaranteed commercial operations date is August 2010.

The payment obligations of PPEA in respect of the Construction Loan, the Revolver, the LC Facility, the Bank Loan and associated interest rate hedging agreements (discussed below) are unconditionally and irrevocably guaranteed by Ambac Assurance Corporation ("Ambac"). Ambac 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 (the "Tax Exempt Bond Policy") as well as a surety bond to satisfy the Borrowers obligations for a Tax Exempt Bond Debt Service Reserve (the "Tax Exempt Bond Debt Reserve Surety"). Ambac was required to issue a debt service reserve surety to meet the requirement for a debt service reserve for the PPEA Credit Agreement Facility after the date the Construction Loan converts to a Bank Loan (the "Credit Agreement Facility Debt Service Reserve Surety"). The credit facilities and insurance policy are secured by a mortgage and security interest (subject to permitted liens) in all of PPEA's assets and contract rights and PPEA's undivided tenancy in common interest in the Plum Point Project and PPEA Holding's interest in PPEA. PPEA 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 December 2009, the lenders on the PPEA Credit Agreement Facility returned Ambac's insurance policy on the Construction Loan, Bank Loan, Revolver and LC Facility to Ambac. In addition, Ambac cancelled its commitment to provide the Tax Exempt Bond Policy, the Tax Exempt Debt Service Reserve Surety and the Credit Agreement Facility Debt Service Reserve Facility. The lenders assert that Ambac and PPEA did not comply with certain of their obligations related to the PPEA Credit Agreement Facility. As a result, the lenders assert that the agent bank has replaced Ambac as the Controlling Party as that term is defined within the PPEA Credit Agreement Facility documents. However, Ambac continues to function as the insurer of PPEA's interest rate swaps.

Under the terms of the PPEA Credit Agreement Facility, PPEA is required to fix the interest rate on a certain percentage of PPEA's floating rate debt, including both the debt issued under the PPEA Credit Agreement Facility and the Tax Exempt Bonds, (together, the "Interest Rate Hedge Requirement"). The lenders have permanently waived this requirement with respect to all dates through December 31, 2009 and have temporarily waived this requirement from January 1, 2010 through March 12, 2010. PPEA does not expect it will be able to meet the Interest Rate Hedge Requirement at all times after March 12, 2010, and therefore, PPEA expects to be in default of the requirements of the PPEA Credit Agreement Facility upon expiration of the waiver. In addition, there are other covenant requirements PPEA is anticipating it will not be able to meet after March 12, 2010. Therefore, as this debt would be callable in the event of such defaults, we have classified borrowings under the PPEA Credit Agreement Facility as a current obligation at December 31, 2009. The PPEA Credit Agreement Facility is a non-recourse facility and our liability (as distinct from the obligations of the holders of the remaining interests in PPEA Holding) would be limited to our $15 million letter of credit supporting our equity commitment. Please read Note 7—Risk Management Activities, Derivatives and Financial Instruments—Cash Flow Hedges for further discussion.

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 PPEA. 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 PPEA's undivided interests in various sewage and solid waste collection and disposal facilities associated with the Plum Point Project. Interest expense on the Tax Exempt Bonds is based on a weekly variable rate and is payable monthly. The interest rates in effect at December 31, 2009 and 2008 were 0.3 percent and 3.50 percent, respectively. The Tax Exempt Bonds mature on April 1, 2036. An event of default under the PPEA Credit Agreement Facility which results in the expiration or cancellation of the LC Facility could result in the mandatory purchase of the bonds. Therefore, we have also classified the debt associated with the Tax Exempt Bonds as a current obligation at December 31, 2009.

The PPEA Credit Agreement Facility and the Tax-Exempts Bonds are non-recourse debt and our liability (as distinct from the obligations of the holders of the remaining interests in PPEA Holding) would be limited to our $15 million letter of credit supporting our equity commitment to PPEA. Please read Note 7—Risk Management Activities, Derivatives and Financial Instruments—Cash Flow Hedges for further discussion.

Restricted Cash and Investments

The following table depicts our restricted cash and investments as of December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in millions)	
Credit facility (1)	$ 850	$ 850
Sithe Energy (2)	36	41
PPEA (3)	19	29
GEN Finance (4)	50	50
Sandy Creek Project (5)	—	275
Total restricted cash and investments	$ 955	$ 1,245

(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) At December 31, 2008, amounts were included that related to our funding commitment related to the Sandy Creek Project. As a result of the sale of our investment in this project, we no longer have this funding commitment. Please read Note 14—Variable Interest Entities—Sandy Creek Project.

Note 18—Related Party Transactions

Transactions with LS Power

On November 30, 2009, we sold certain assets to LS Power, including our interest in two investments in joint ventures in which LS Power or its affiliates were also investors. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion.

We had 50 percent ownership interests in SCEA and SC Services, and subsidiaries of LS Power held the remaining 50 percent interests. We recorded a loss of approximately $84 million related to this sale in the fourth quarter 2009. Please see Note 14—Variable Interest Entities—Sandy Creek for further discussion.

We held two other investments in joint ventures in which LS Power or its affiliates were also investors. Dynegy had a 50 percent ownership interest in DLS Power Holdings and DLS Power Development. In December 2008, Dynegy and LS Power Associates, L.P. agreed to dissolve the two companies' development joint venture. Please read Note 14—Variable Interest Entities for further discussion.

Subsequent to the dissolution of DLS Power Holdings and DLS Power Development, Dynegy acquired exclusive rights, ownership and developmental control of substantially all repowering or expansion opportunities related to its existing portfolio of operating assets, and subsequently contributed approximately $15 million of these assets and approximately $21 million of deferred tax assets associated with these assets to DHI.

Upon completion of the agreement with LS Power discussed above, assets related to repowering or expansion opportunities at the Bridgeport and Arizona power generating facilities were transferred to LS Power in connection with the sale of those facilities. Please read Note 14—Variable Interest Entities—DLS Power Holdings and DLS Power Development for further information.

DHI's affiliate transactions during the year ended December 31, 2009 included $97 million related to the LS Power Transactions. Dynegy repurchased 245 million shares of its Class B common stock with a fair value of $443 million (based on a share price of $1.81 on November 30, 2009) from LS Power by exchanging assets owned by DHI for the shares. In order to effect this exchange, Dynegy paid $540 million cash to LS Power in exchange for the shares, immediately following which a separate subsidiary of LS Power paid $540 million of cash to DHI in exchange for the assets. The $97 million represents the difference between the $540 million cash received by DHI and the $443 million fair value of the shares received by Dynegy.

Transactions with Chevron

On April 2, 2007, in connection with the LS Power Merger, the ownership interest of 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 year ended December 31, 2007, we recognized net purchases from CUSA of $22 million. All of these transactions, whether physically or financially settled, have been presented net on the consolidated statements of operations.

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 year ended December 31, 2007, our portion of the net income from joint ventures with CUSA was approximately $7 million.

Other

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 $585 million (inclusive of a $410 million dividend to Dynegy which was used by Dynegy to repurchase a portion of the 245 million shares of Dynegy's Class B common stock discussed previously) and $342 million to Dynegy during the years ended December 31, 2009 and 2007, respectively.

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 14—Variable Interest Entities—Sandy Creek Project for further information.

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. During the year ended December 31, 2009, DHI recorded $50 million of affiliate transactions with Dynegy, including $97 million related to the LS Power Transactions as discussed above, partly offset by $48 million of other activity in the normal course of business, primarily related to the reallocation of deferred taxes between legal entities in accordance with applicable IRS regulations. As a result of such transactions, DHI has recorded over time a receivable from Dynegy in the aggregate amount of $777 million and $827 million at December 31, 2009 and 2008, 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 sheets as of December 31, 2009 and 2008.

Note 19—Income Taxes

Income Tax (Expense) Benefit-Dynegy. We are subject to U.S. federal 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, 2009	2008 (in millions)	2007
Income (loss) from continuing operations before income taxes:			
Domestic	$ (1,355)	$ 250	$ 251
Foreign	—	28	(6)
	$ (1,355)	$ 278	$ 245

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

	Year Ended December 31, 2009	2008 (in millions)	2007
Current tax expense:			
Domestic	$ (3)	$ (5)	$ (22)
Foreign	—	—	—
Deferred tax benefit (expense):			
Domestic	318	(81)	(121)
Foreign	—	(4)	3
Income tax (expense) benefit	$ 315	$ (90)	$ (140)

Dynegy's income tax (expense) benefit related to income (loss) from continuing operations for the years ended December 31, 2009, 2008 and 2007, was equivalent to effective rates of 23 percent, 32 percent and 57 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, 2009	2008 (in millions)	2007
Expected tax (expense) benefit at U.S. statutory rate (35%)	$ 474	$ (97)	$ (86)
State taxes (1)	25	(2)	(54)
Foreign taxes	—	—	5
Permanent differences (2)	(175)	7	(2)
Valuation allowance	(12)	(6)	—
IRS and state audits and settlements	8	—	(3)
Other (3)	(5)	8	—
Income tax (expense) benefit	$ 315	$ (90)	$ (140)

(1) Dynegy incurred a state tax benefit for the year ended December 31, 2009 due to current year losses which will reduce future state cash taxes, changes in its state sale profile, and the exit from various states due to the LS Power Transactions. Also, 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 $151 million related to nondeductible goodwill impairment expense and $18 million related to nondeductible losses in connection with the LS Power transaction.
(3) 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, 2009	2008	2007
		(in millions)	
Income (loss) from continuing operations before income taxes:			
Domestic	$ (1,359)	$ 332	$ 276
Foreign	—	28	(6)
	$ (1,359)	$ 360	$ 270

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

	Year Ended December 31, 2009	2008	2007
		(in millions)	
Current tax expense:			
Domestic	$ (2)	$ (3)	$ (11)
Foreign	—	—	—
Deferred tax benefit (expense):			
Domestic	315	(131)	(97)
Foreign	—	(4)	3
Income tax (expense) benefit	$ 313	$ (138)	$ (105)

DHI's income tax (expense) benefit related to income (loss) from continuing operations for the years ended December 31, 2009, 2008 and 2007, was equivalent to effective rates of 23 percent, 38 percent and 39 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, 2009	2008	2007
		(in millions)	
Expected tax benefit at U.S. statutory rate (35%)	$ 476	$ (126)	$ (94)
State taxes (1)	25	(16)	(20)
Foreign taxes	—	—	5
Permanent differences (2)	(175)	7	(2)
Valuation allowance	(11)	(6)	—
IRS and state audits and settlements	1	—	8
Other (3)	(3)	3	(2)
Income tax (expense) benefit	$ 313	$ (138)	$ (105)

(1) DHI incurred a state tax benefit for the year ended December 31, 2009 due to current year losses which will reduce future state cash taxes, changes in its state sale profile, and the exit from various states due to the LS Power Transactions. Also, 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 $151 million related to nondeductible goodwill impairment expense and $18 million related to nondeductible losses in connection with the LS Power transaction.

(3) 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,			
	2009		2008		2009		2008	
	(in millions)							
Deferred tax assets:								
Current:								
Reserves (legal, environmental and other)	$	10	$	—	$	11	$	—
NOL carryforwards		—		13		—		12
Miscellaneous book/tax recognition differences		—		4		—		4
Subtotal		10		17		11		16
Less: valuation allowance		(4)		(5)		(4)		(5)
Total current deferred tax assets		6		12		7		11
Non-current:								
NOL carryforwards		166		35		151		35
AMT credit carryforwards		272		271		—		—
Capital loss carryforward		—		10		—		10
Reserves (legal, environmental and other)		2		42		2		42
Other comprehensive income		97		146		97		146
Miscellaneous book/tax recognition differences		7		71		3		47
Subtotal		544		575		253		280
Less: valuation allowance		(31)		(32)		(30)		(32)
Total non-current deferred tax assets		513		543		223		248
Deferred tax liabilities:								
Current:								
Reserves (legal, environmental and other)		—		6		—		8
Total current deferred tax liabilities		—		6		—		8
Non-current:								
Depreciation and other property differences		1,240		1,620		871		1,207
Power contract		53		89		56		93
Total non-current deferred tax liabilities		1,293		1,709		927		1,300
Net deferred tax liability	$	774	$	1,160	$	697	$	1,049

NOL Carryforwards-Dynegy. At December 31, 2009, Dynegy had approximately $359 million of regular federal tax NOL carryforwards and $1,271 million 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, 2009 for Dynegy's federal NOL carryforwards, as management believes reversing temporary differences will be sufficient to realize deferred tax assets for which no reserve has been established.

At December 31, 2009 and 2008, state NOL carryforwards totaled $843 million and $815 million, respectively. At December 31, 2009 and 2008, foreign NOL carryforwards totaled zero and $4 million, respectively.

NOL Carryforwards-DHI. At December 31, 2009, DHI had approximately $316 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, 2009 for DHI's federal NOL carryforwards, as management believes reversing temporary differences will be sufficient to realize deferred tax assets for which no reserve has been established.

At December 31, 2009 and 2008, state NOL carryforwards totaled $834 million and $815 million, respectively. At December 31, 2009 and 2008, foreign NOL carryforwards totaled zero and $4 million, respectively.

AMT Credit Carryforwards. At December 31, 2009, Dynegy had approximately $272 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, 2009 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 on future taxable net income and future reversals of existing taxable temporary differences.

Capital Loss Carryforwards. At December 31, 2009, we had no federal capital loss carryforwards. All capital loss carryforwards expired in 2009.

Residual U.S. Income Tax on Foreign Earnings. We no longer have foreign operations subject to foreign tax, and have no undistributed non-previously taxed earnings from prior foreign operations.

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, 2009, valuation allowances related to state NOL carryforwards and credits have been established. During 2009, we eliminated our valuation allowance associated with capital loss carryforwards that expired in 2009 and other foreign book-tax differences and increased our valuation allowance on state NOL carryforwards and credits. 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.

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

	Capital Loss Carryforwards	Foreign Tax Credits	State NOL Carryforwards and Credits	Foreign NOL Carryforwards and Deferred Tax Assets	Total
			(in millions)		
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)
Changes in valuation allowance—continuing operations	—	—	(12)	—	(12)
Other release	10	—	—	4	14
Balance as of December 31, 2009	$ —	$ —	$ (35)	$ —	$ (35)

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

	Capital Loss Carryforwards	Foreign Tax Credits	State NOL Carryforwards and Credits	Foreign NOL Carryforwards and Deferred Tax Assets	Total
			(in millions)		
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)
Changes in valuation allowance—continuing operations	—	—	(11)	—	(11)
Other release	10	—	—	4	14
Balance as of December 31, 2009	$ —	$ —	$ (34)	$ —	$ (34)

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. 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 finalized the IRS audit of our 2004-2005 tax years in 2009 and expect to finalize our 2006-2007 audit in the first quarter 2010. As a result of the settlement of our 2004-2005 audit, adjustments to tax positions related to prior years, and various state settlements, we recorded, and included in our income tax expense, a benefit of $5 million, a benefit of $1 million and an expense of $8 million for the years ended December 31, 2009, 2008 and 2007, respectively. DHI recorded, and included in its income tax expense, an expense of $1 million, a benefit of $1 million and a benefit of $2 million for years ended December 31, 2009, 2008 and 2007, respectively.

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
Additions based on tax positions related to the prior year	6	6
Reductions based on tax positions related to the prior year	(4)	(2)
Settlements	(9)	6
Balance at December 31, 2009	$ 25	$ 17

As of December 31, 2009, 2008 and 2007, approximately $24 million, $30 million and $31 million, respectively, of unrecognized tax benefits would impact Dynegy's effective tax rate if recognized. As of December 31, 2009, 2008 and 2007, approximately $16 million, $6 million and $6 million, respectively, 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, 2009 primarily resulted from changes in various federal and 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, 2009 is less than $1 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 the years ended December 31, 2009, 2008 and 2007, we recognized less than $1 million in interest and penalties. Dynegy and DHI had approximately $2 million, $2 million and $(1) million accrued for the payment of interest and penalties at December 31, 2009, 2008 and 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 20—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,		
	2009	2008	2007
	(in millions, except per share amounts)		
Income (loss) from continuing operations	$ (1,040)	$ 188	$ 105
Less: Net income (loss) attributable to the noncontrolling interests	(15)	(3)	7
Income (loss) from continuing operations attributable to Dynegy Inc. for basic and diluted earnings (loss) per share	$ (1,025)	$ 191	$ 98
Basic weighted-average shares	822	840	752
Effect of dilutive securities - stock options and restricted stock	4	2	2
Diluted weighted-average shares	826	842	754
Earnings (loss) per share from continuing operations attributable to Dynegy Inc.:			
Basic	$ (1.25)	0.23	0.13
Diluted (1)	$ (1.25)	0.23	0.13

(1) When an entity has a net loss from continuing operations adjusted for preferred dividends, it is prohibited from including 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, 2009.

Note 21—Commitments and Contingencies

Legal Proceedings

Set forth below is a summary of our material ongoing legal proceedings. 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 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 the Tennessee Supreme 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. Thereafter, defendants appealed to the Tennessee Supreme Court which held oral argument in November 2009.
- 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. In November 2009, the Nevada District Court granted defendants' motion for reconsideration on a previously denied motion for summary judgment on the issue of federal preemption. The court invited defendants to renew their motions for summary judgment, which were filed shortly thereafter. A briefing schedule was entered on defendants' motions as well as plaintiffs' motions to amend their complaints to add federal claims. Per the order, briefing is expected to continue through the first quarter 2010. In the interim, discovery and plaintiffs' class certification motion are stayed.

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.

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 BTA for minimizing adverse environmental impact. These standards are developed and implemented for power generating facilities through the NPDES permits or individual 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 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 EPA for further rulemaking. Several parties sought review of the decision before the U.S. Supreme Court . In April 2009, the U.S. Supreme Court ruled that EPA permissibly relied on cost-benefit analysis in setting the national BTA performance standard and in providing for cost-benefit variances from those standards as part of the Phase II Rules.

Following remand of the rules by the U.S. Court of Appeals for the 2nd Circuit, the EPA suspended its Phase II Rules in July 2007 and advised that permit requirements for cooling water intake structures at existing facilities should be established on a case-by-case best professional judgment basis until replacement rules are issued. The scope of requirements and the compliance methodologies that will ultimately be allowed by future rulemaking may become more restrictive, resulting in potentially significant increased costs. In addition, the timing for compliance may be adjusted.

The environmental groups that participate in our 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. The adjudicatory hearing on the Draft Roseton SPDES Permit will be scheduled after the Commissioner rules on the appeal. 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. The California Supreme Court deferred further action pending final disposition of the U.S. Supreme Court challenge regarding the Phase II Rule. The California Supreme Court directed the parties to brief all issues raised by the pleadings. The petitioner's brief was filed in December 2009 and our response is due in March 2010. 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 GHG 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 based on the court's lack of subject matter jurisdiction over plaintiffs' federal claim for common law nuisance. In particular, defendants argued that under the political question doctrine, the court lacks jurisdiction to consider the merits of plaintiffs' nuisance claim because its resolution would require the court to make policy determinations which are inherently political. In October 2009, the court granted defendants' motions and dismissed all of plaintiffs' claims. Shortly thereafter, plaintiffs appealed to the Ninth Circuit. The Court's initial briefing schedule extends through March 2010. We believe the plaintiffs' suit lacks merit and we will continue 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, 2009.

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 $180 million as of December 31, 2009.

Coal Commitments. At December 31, 2009, we had contracts in place to supply coal to various of our generation facilities with minimum commitments of $391 million. Obligations related to the purchase of coal were $372 million through 2012, and obligations related to the transportation were $19 million through 2013.

Midwest Consent Decree. In 2005, we settled a lawsuit filed by the 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 (the "Midwest Consent Decree") was finalized in July 2005. Among other provisions of the Midwest 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 $545 million through December 31, 2009 related to these Midwest Consent Decree projects and anticipate incurring significantly more costs over the course of the next four years in connection with the Midwest 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.

DNE Leveraged Lease. 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, 2009, the termination payment would be approximately $853 million for all of the DNE facilities.

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 $10 million over the remaining term of the lease. Minimum commitments at December 31, 2009 were $2 million for each of the years ending 2010, 2011, 2012 and 2013 and a total of $2 million thereafter.

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 through the term of the contract.

Minimum commitments in connection with office space, equipment, plant sites and other leased assets, including the leases discussed above, at December 31, 2009, were as follows: 2010—$107 million, 2011—$122 million, 2012—$183 million, 2013—$148 million, 2014—$147 million and beyond—$261 million.

Rental payments made under the terms of these arrangements totaled $154 million in 2009, $148 million in 2008 and $122 million in 2007.

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 2010 through 2012, and approximately $17 million in aggregate for the period from 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, 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 $2 million as of December 31, 2009.

LS Power Indemnities. In connection with the LS Power Transactions, we agreed in the purchase and sale agreement to indemnify LS Power against claims regarding any breaches in our representations and warranties and certain other potential liabilities. Claims for indemnification shall survive until twelve months subsequent to closing with exceptions for tax claims, which shall survive for the applicable statute of limitations plus 30 days, and certain other representations and potential liabilities, which shall survive indefinitely. The indemnifications provided to LS Power are limited to $1.3 billion in total; however, several categories of indemnifications are not available to LS Power until the liabilities incurred in the aggregate are equal to or exceed $15 million and are capped at a maximum of $100 million. Further, the purchase and sale agreement provides in part that we may not reduce or avoid liability for a valid claim based on a claim of contribution. In addition to the above indemnities related to the LS Power Transactions, we have agreed to indemnify LS Power against claims related to the Riverside/Foothills Project for certain aspects of the project. Namely, LS Power has been indemnified for any disputes that arise as to ownership, transfer of bonds related to the project, and any failure by us to obtain approval for the transfer of the payment in-lieu of taxes program already in place. The indemnities related solely to the Riverside/Foothills Project are capped at a maximum of $180 million and extend until the earlier of the expiration of the tax agreement or December 26, 2026. At this time, we have incurred no significant expenses under these indemnities. Please see Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for more information.

West Coast Power Indemnities. In connection with the sale of our 50 percent interest in West Coast Power to NRG in 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 our midstream business ("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, 2009, 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, 2009, no claims have been made against these indemnities.

Note 22—Capital Stock

At December 31, 2009, 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 of Class B common stock, $0.01 per 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, 2009, there were 603,577,577 shares of Dynegy Class A common stock issued in the aggregate and 2,788,383 shares were held in treasury. During 2009 and 2008, no quarterly cash dividends were paid by Dynegy.

In 2007, Dynegy established two classes of common shares, Class A and Class B. All of Dynegy's outstanding Class B common stock was owned by the LS Power. On November 30, 2009, as part of the LS Power Transactions, Dynegy purchased 245 million shares of Dynegy's Class B common stock. The remaining 95 million shares of Dynegy's Class B common stock then held by LS Power were converted to Dynegy's Class A common shares. As a result of the LS Power Transactions, there are currently no outstanding Class B common shares.

Common stock activity for the three years ended December 31, 2009 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, 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
401(k) plan and profit sharing	3	—	—	—	—	—
LS Power Transactions:						
Conversion of LS Power Class B shares to Class A shares	95	1	—	—	(95)	(1)
Retirement of Class B shares	—	—	—	—	(245)	(2)
December 31, 2009	604	$ 6	—	$ —	—	$ —

Treasury Stock. During 2009, 2008 and 2007, Class A common shares purchased into treasury totaled 220,097, 119,027 and 662,255, 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 $1.13 per share to $52.50 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 through May 2006. All option grants are vested, and options will expire ten years from the date of the grant.
- ***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 through May 2002. Grants under this plan vested on the fifth anniversary from the date of the grant. All option grants are vested, and options will expire ten years from the date of the grant.
- ***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, and options will expire ten years from the date of the grant.
- ***Extant Plan.*** Adopted by Extant prior to its acquisition by Dynegy, this plan provided for the issuance of 202,577 authorized shares through September 2000. Grants from this plan vested at

25 percent per year. All option grants are vested, and options will expire ten years from the date of the grant.

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

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 LS Power 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 LS Power 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.

Compensation expense related to options granted and restricted stock awarded totaled $11 million, $15 million and $19 million for the years ended December 31, 2009, 2008 and 2007, 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 $4 million, $5 million and $8 million for the years ended December 31, 2009, 2008 and 2007, respectively. As of December 31, 2009, $7 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 1.4 years. The total fair value of shares vested was $12 million, $7 million and $20 million for the years ended December 31, 2009, 2008 and 2007, respectively. We did not capitalize or use cash to settle any share-based compensation in the years ended December 31, 2009, 2008 or 2007, other than as described above.

Cash received from option exercises for the years ended December 31, 2009, 2008 and 2007 was zero, $2 million and $4 million, and the tax benefit realized for the additional tax deduction from share-based payment awards totaled zero, $3 million and $4 million, respectively. The total intrinsic value of options exercised and released for the years ended December 31, 2009, 2008 and 2007 was $1 million, $5 million and $23 million, respectively.

In 2009, we granted stock-based compensation awards to certain of our employees that cliff vest after three years based partly on the achievement of a certain target for Dynegy's stock price for February 2012 and partly on the achievement of a certain earnings targets for 2010-2012. In 2008, we granted stock-based compensation awards to certain of our employees that cliff vest after three years based on the achievement of a certain target for Dynegy's stock price for February 2011. In 2007, we granted stock-based compensation awards to certain of our employees that cliff vest after three years based on the achievement of a certain target for Dynegy's stock price for February 2010. A net compensation benefit of $1 million was recorded during the year ended December 31, 2009. This benefit was due to the change in fair value of our outstanding awards reflecting current market conditions. 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 LS Power 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, 2009, 2008 and 2007 was as follows:

	Year Ended December 31,					
	2009		2008		2007	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
			(options in thousands)			
Outstanding at beginning of period	8,816	$ 11.93	8,420	$ 12.60	7,361	$ 12.63
Granted	6,332	$ 1.13	1,565	$ 7.48	2,136	$ 9.67
Exercised	(20)	$ 1.13	(555)	$ 4.03	(872)	$ 4.29
Cancelled or expired	(759)	$ 17.22	(614)	$ 16.88	(205)	$ 18.60
Outstanding at end of period	14,369	$ 6.91	8,816	$ 11.93	8,420	$ 12.60
Vested and unvested expected to vest	14,369	$ 6.91	8,702	$ 11.98	8,137	$ 12.70
Exercisable at end of period	6,426	$ 12.15	5,878	$ 13.64	6,305	$ 13.59

	Year Ended December 31, 2009	
	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at end of period	7.04	$4.30
Vested and unvested expected to vest	7.04	$4.30
Exercisable at end of period	5.02	$0.04

During the three-year period ended December 31, 2009, 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, 2009 are summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options Outstanding at December 31, 2009	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number of Options Exercisable at December 31, 2009	Weighted Average Exercise Price
	(options in thousands)				
$1.13	6,311	8.92	$ 1.13	59	$ 1.13
$1.77-4.48	627	3.70	$ 3.72	627	$ 3.72
$4.88	2,402	6.21	$ 4.88	2,402	$ 4.88
$7.48	1,541	7.91	$ 7.48	532	$ 7.48
$8.70	3	0.12	$ 8.70	3	$ 8.70
$9.67	2,046	6.81	$ 9.67	1,367	$ 9.67
$10.17-$47.98	1,429	1.09	$ 32.35	1,426	$ 32.39
$48.01	2	1.45	$ 48.01	2	$ 48.01
$50.63	3	0.79	$ 50.63	3	$ 50.63
$52.50	5	0.70	$ 52.50	5	$ 52.50
	14,369			6,426	

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,		
	2009	2008	2007
Dividends	—	—	—
Expected volatility (historical)	61.04%	45.07%	45.60%
Risk-free interest rate	2.834%	3.80%	4.9%
Expected option life	6 Years	5 Years	4 Years

The expected volatility was calculated based on a six-, five- and four-year historical volatility of Dynegy's Class A common stock price for the years ended December 31, 2009, 2008 and 2007, 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 authoritative guidance issued by the SEC. 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, 2009, 2008 and 2007 was $0.66, $3.63 and $4.91, respectively.

Restricted stock activity for the three years ended December 31, 2009 was as follows:

	Year Ended December 31,			
	2009	2009 Weighted Average Grant Date Fair Value	2008	2007
	(restricted stock shares in thousands)			
Outstanding at beginning of period	2,545	$ 8.48	1,552	2,114
Granted	—	$ —	1,445 (1)	1,643 (2)
Vested	(690)	$ 8.48	(367)	(2,113)
Cancelled or expired	(93)	$ 8.12	(85)	(92)
Outstanding at end of period	1,762	$ 8.50	2,545	1,552

(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.

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 LS Power 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 23—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.

Phantom Stock Plan. In 2009 Dynegy issued phantom stock units under its 2009 Phantom Stock Plan. Units awarded under this plan are long term incentive awards that grant the participant the right to receive a cash payment based on the fair market value of the of Dynegy's stock on the vesting date of the award. As these awards must be settled in cash, we account for them as liabilities, with changes in the fair value of the liability recognized as expense in our consolidated statements of operations. Expense recognized in connection with these awards was $12 million for the year ended December 31 2009.

401(k) Savings Plans. For the three years ended December 31, 2009, 2008 and 2007, 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 was previously 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, 2009, 2008 and 2007, we issued approximately 2.1 million, 0.8 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, 2009.

- ***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, 2009, 2008 and 2007, we issued 0.7 million, 0.3 million and 0.1 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, 2009.

- ***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, 2009, 2008 and 2007, we recognized aggregate costs related to these employee compensation plans of $5 million, $5 million and $4 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 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	
	2009	2008	2009	2008
	(in millions)			
Projected benefit obligation, beginning of the year	$ 217	$ 182	$ 61	$ 58
Service cost	12	11	3	3
Interest cost	13	11	3	4
Actuarial (gain) loss	6	17	(1)	(2)
Benefits paid	(6)	(4)	(1)	(1)
Plan amendments	—	—	—	(1)
Projected benefit obligation, end of the year	$ 242	$ 217	$ 65	$ 61
Fair value of plan assets, beginning of the year	$ 135	$ 154	$ —	$ —
Actual return on plan assets	30	(44)	—	—
Employer contributions	27	29	1	1
Benefits paid	(6)	(4)	(1)	(1)
Fair value of plan assets, end of the year	$ 186	$ 135	$ —	$ —
Funded status	$ (56)	$ (82)	$ (65)	$ (61)

The accumulated benefit obligation for all defined benefit pension plans was $214 million and $187 million at December 31, 2009 and 2008, 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, 2009:

	December 31,	
	2009	2008
	(in millions)	
Projected benefit obligation	$ 242	$ 217
Accumulated benefit obligation	214	187
Fair value of plan assets	186	135

Pre-tax amounts recognized in accumulated other comprehensive income (loss) consist of:

	Year Ended December 31,			
	2009		2008	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
	(in millions)			
Prior service cost	$ 5	$ (1)	$ 5	$ (1)
Actuarial loss	82	10	95	11
Net amount recognized	$ 87	$ 9	$ 100	$ 10

Amounts recognized in the consolidated balance sheets consist of:

	Year Ended December 31, 2009 Pension Benefits	2009 Other Benefits	2008 Pension Benefits	2008 Other Benefits
	(in millions)			
Current liabilities	$ —	$ (1)	$ —	$ (1)
Noncurrent liabilities	(56)	(64)	(82)	(60)
Net amount recognized	$ (56)	$ (65)	$ (82)	$ (61)

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, 2010 for the defined benefit pension plans are less than $5 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, 2010 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 2009	Pension Benefits 2008	Pension Benefits 2007	Other Benefits 2009	Other Benefits 2008	Other Benefits 2007
	(in millions)					
Service cost benefits earned during period	$ 12	$ 11	$ 10	$ 3	$ 3	$ 3
Interest cost on projected benefit obligation	13	11	10	3	4	4
Expected return on plan assets	(14)	(13)	(11)	—	—	—
Amortization of prior service costs	—	1	1	—	—	—
Recognized net actuarial loss	4	—	1	1	—	1
Total net periodic benefit cost	$ 15	$ 10	$ 11	$ 7	$ 7	$ 8

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

	Pension Benefits December 31, 2009	Pension Benefits December 31, 2008	Other Benefits December 31, 2009	Other Benefits December 31, 2008
Discount rate (1)	5.86%	6.12%	5.92%	5.93%
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 Year Ended December 31, 2009	2008	2007	Other Benefits Year Ended December 31, 2009	2008	2007
Discount rate	6.12%	6.46%	5.87%	5.93%	6.48%	5.90%
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, 2010 will be 8.00 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, 2009	December 31, 2008
Health care cost trend rate assumed for next year	8.00%	7.83%
Ultimate trend rate	4.90%	4.90%
Year that the rate reaches the ultimate trend rate	2060	2060

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. The target allocations for plan assets are thirty-five percent fixed income securities, forty percent U.S. equity securities, five percent non-US equity securities, and twenty percent global equity securities.

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.

The following table sets forth by level within the fair value hierarchy assets that were accounted for at fair value related to our pension plans. These assets 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, 2009			
	Level 1	Level 2	Level 3	Total
		(in millions)		
Equity securities:				
U.S. companies (1)	$ —	$ 76	$ —	$ 76
Non-U.S. companies (2)	—	9	—	9
International (3)	—	38	—	38
Fixed income securities (4)	37	26	—	63
Total	$ 37	$ 149	$ —	$ 186

(1) This category comprises a domestic common collective trust not actively managed that tracks the Dow Jones total U.S. stock market.

(2) This category comprises a common collective trust not actively managed that tracks the MSCI All Country World Ex-US Index.
(3) This category comprises actively managed common collective trusts that hold U.S. and foreign equities. These trusts track the MSCI World Index.
(4) This category includes a mutual fund and a trust that invest primarily in investment grade corporate bonds.

Contributions and Payments. During the year ended December 31, 2009, we contributed approximately \$27 million to our pension plans and \$1 million to our other post-retirement benefit plans. In 2010, we expect to contribute approximately \$19 million to our pension plans and \$2 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)	
2010	\$ 11	\$ 2
2011	12	2
2012	11	2
2013	11	3
2014	13	3
2015 – 2019	87	21

Note 24—Segment Information

We report results of our power generation business in the following segments: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Because of the diversity among their respective operations and how we allocate our resources, we report the results of each business as a separate segment in our consolidated financial statements. The results of our legacy operations, including CRM, are included in Other. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest and depreciation and amortization.

During 2009, two customers in our GEN-MW segment and one customer in our GEN-NE segment accounted for approximately 19 percent, 11 percent and 12 percent of our consolidated revenues, respectively. During 2008, one customer in our GEN-MW segment and one customer in our GEN-NE segment accounted for approximately 27 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 25 percent, 12 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 7—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, 2009, 2008 and 2007 is presented below:

Dynegy's Segment Data as of and for the Year Ended December 31, 2009 (in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$ 1,257	$ 380	$ 834	$ (3)	$ 2,468
Other	—	—	—	—	—
Total revenues	$ 1,257	$ 380	$ 834	$ (3)	$ 2,468
Depreciation and amortization	$ (215)	$ (62)	$ (47)	$ (11)	$ (335)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairment and other charges	(147)	—	(391)	—	(538)
Operating loss	$ (4)	$ (218)	$ (444)	$ (168)	$ (834)
Earnings (losses) from unconsolidated investments	—	(72)	—	1	(71)
Other items, net	2	3	1	5	11
Interest expense and debt extinguishment costs					(461)
Loss from continuing operations before taxes					(1,355)
Income tax benefit					315
Loss from continuing operations					(1,040)
Loss from discontinued operations, net of taxes					(222)
Net loss					(1,262)
Less: Net loss attributable to the noncontrolling interests					(15)
Net loss attributable to Dynegy Inc.					$ (1,247)
Identifiable assets:					
Domestic	$ 6,035	$ 1,762	$ 1,751	$ 1,381	$ 10,929
Other	—	—	—	24	24
Total	$ 6,035	$ 1,762	$ 1,751	$ 1,405	$ 10,953
Capital expenditures	$ (533)	$ (45)	$ (28)	$ (6)	$ (612)

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	$ 1,621	$ 702	$ 890	$ (5)	$ 3,208
Other	—	—	116	—	116
Total revenues	$ 1,621	$ 702	$ 1,006	$ (5)	$ 3,324
Depreciation and amortization	$ (205)	$ (77)	$ (54)	$ (10)	$ (346)
Impairment and other charges	—	—	—	—	—
Operating income (loss)	$ 686	$ 123	$ 67	$ (132)	$ 744
Losses from unconsolidated investments	—	(40)	—	(83)	(123)
Other items, net	—	5	6	73	84
Interest expense					(427)
Income from continuing operations before taxes					278
Income tax expense					(90)
Income from continuing operations					188
Loss from discontinued operations, net of taxes					(17)
Net income					171
Less: Net loss attributable to the noncontrolling interests					(3)
Net income attributable to Dynegy Inc.					$ 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	$ 1,323	$ 506	$ 920	$ 12	$ 2,761
Other	—	—	156	1	157
Total revenues	$ 1,323	$ 506	$ 1,076	$ 13	$ 2,918
Depreciation and amortization	$ (193)	$ (55)	$ (45)	$ (13)	$ (306)
Operating income (loss)	$ 498	$ 98	$ 164	$ (184)	$ 576
Earnings (losses) from unconsolidated investments	—	6	—	(9)	(3)
Other items, net	—	—	—	56	56
Interest expense					(384)
Income from continuing operations before taxes					245
Income tax expense					(140)
Income from continuing operations					105
Income from discontinued operations, net of taxes					166
Net income					271
Less: Net income attributable to the noncontrolling interests					7
Net income attributable to Dynegy Inc.					$ 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)

Reportable segment information for DHI, including intercompany transactions accounted for at prevailing market rates, for the years ended December 31, 2009, 2008 and 2007 is presented below:

DHI's Segment Data as of and for the Year Ended December 31, 2009
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$ 1,257	$ 380	$ 834	$ (3)	$ 2,468
Other	—	—	—	—	—
Total revenues	$ 1,257	$ 380	$ 834	$ (3)	$ 2,468
Depreciation and amortization	$ (215)	$ (62)	$ (47)	$ (11)	$ (335)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairment and other charges	(147)	—	(391)	—	(538)
Operating loss	$ (4)	$ (218)	$ (444)	$ (170)	$ (836)
Losses from unconsolidated investments	—	(72)	—	—	(72)
Other items, net	2	3	1	4	10
Interest expense and debt extinguishment costs					(461)
Loss from continuing operations before taxes					(1,359)
Income tax benefit					313
Loss from continuing operations					(1,046)
Loss from discontinued operations, net of taxes					(222)
Net loss					(1,268)
Less: Net loss attributable to the noncontrolling interests					(15)
Net loss attributable to Dynegy Holdings Inc.					$ (1,253)
Identifiable assets:					
Domestic	$ 6,035	$ 1,762	$ 1,751	$ 1,331	$ 10,879
Other	—	—	—	24	24
Total	$ 6,035	$ 1,762	$ 1,751	$ 1,355	$ 10,903
Capital expenditures	$ (533)	$ (45)	$ (28)	$ (6)	$ (612)

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	$ 1,621	$ 702	$ 890	$ (5)	$ 3,208
Other	—	—	116	—	116
Total revenues	$ 1,621	$ 702	$ 1,006	$ (5)	$ 3,324
Depreciation and amortization	$ (205)	$ (77)	$ (54)	$ (10)	$ (346)
Impairment and other charges	—	—	—	—	—
Operating income (loss)	$ 686	$ 123	$ 67	$ (132)	$ 744
Losses from unconsolidated investments	—	(40)	—	—	(40)
Other items, net	—	5	6	72	83
Interest expense					(427)
Income from continuing operations before taxes					360
Income tax expense					(138)
Income from continuing operations					222
Loss from discontinued operations, net of taxes					(17)
Net income					205
Less: Net loss attributable to the noncontrolling interests					(3)
Net income attributable to Dynegy Holdings Inc.					$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	$ 1,323	$ 506	$ 920	$ 12	$ 2,761
Other	—	—	156	1	157
Total revenues	$ 1,323	$ 506	$ 1,076	$ 13	$ 2,918
Depreciation and amortization	$ (193)	$ (55)	$ (45)	$ (13)	$ (306)
Operating income (loss)	$ 498	$ 98	$ 164	$ (165)	$ 595
Earnings from unconsolidated investments	—	6	—	—	6
Other items, net	—	—	—	53	53
Interest expense					(384)
Income from continuing operations before taxes					270
Income tax expense					(105)
Income from continuing operations					165
Income from discontinued operations, net of taxes					166
Net income					$ 331
Less: Net income attributable to the noncontrolling interests					7
Net income attributable to Dynegy Holdings Inc.					$ 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)

Note 25—Quarterly Financial Information (Unaudited)

The following is a summary of Dynegy's unaudited quarterly financial information for the years ended December 31, 2009 and 2008:

	Quarter Ended			
	March 2009	June 2009	September 2009	December 2009
	(in millions, except per share data)			
Revenues	$ 904	$ 450	$ 673	$ 441
Operating loss	(146)	(471)	(7)	(210)
Net loss	(337)(1)	(346)(2)	(223)(3)	(356)(4)
Net loss attributable to Dynegy Inc. common stockholders	(335)(1)	(345)(2)	(212)(3)	(355)(4)
Net loss per share attributable to Dynegy Inc. common stockholders	$ (0.40)(1)	$ (0.41)(2)	$ (0.25)(3)	$ (0.47)(4)

(1) Includes goodwill impairment charges of $433 million. Please read Note 15—Goodwill for further discussion. Includes impairment charges of $5 million (discontinued operations) related to the assets included in the LS Power Transactions. Please read Note 6—Impairment Charges for further discussion.

(2) Includes impairment charges of $179 million (continuing operations) and $18 million (discontinued operations) related to the assets included in the LS Power Transactions and $208 million related to Roseton and Danskammer. Please read Note 6—Impairment Charges for further discussion.

(3) Includes impairment charges of $147 million (continuing operations) and $235 million (discontinued operations) related to the assets included in the LS Power Transactions and $1 million related to Roseton and Danskammer. Please read Note 6—Impairment Charges for further discussion.

(4) Includes pre-tax charges of $312 million related to the sale of assets to LS Power. This charge is comprised of $124 million included in Gain (loss) on sale of assets, $104 million included in Income (loss) from discontinued operations and $84 million included in Losses from unconsolidated investments. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion. In addition, includes $46 million debt extinguishment costs for the 2011 and 2012 senior unsecured debt repayment. Please read Note 17—Debt—Credit Facility for further discussion.

	Quarter Ended			
	March 2008	June 2008	September 2008	December 2008
	(in millions, except per share data)			
Revenues	$ 530	$ 261	$ 1,759	$ 774
Operating income (loss)	(130)	(354)	1,063	165
Net income (loss)	(152)	(274)	604(1)	(7)(2)
Net income (loss) attributable to Dynegy Inc. common stockholders	(152)	(272)	605(1)	(7)(2)
Net income (loss) per share attributable to Dynegy Inc. common stockholders	$ (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 6—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 14—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.

The following is a summary of DHI's unaudited quarterly financial information for the years ended December 31, 2009 and 2008:

	Quarter Ended			
	March 2009	June 2009	September 2009	December 2009
	(in millions, except per share data)			
Revenues	$ 904	$ 450	$ 673	$ 441
Operating loss	(148)	(471)	(7)	(210)
Net loss	(337)(1)	(336)(2)	(232)(3)	(363)(4)
Net loss attributable to Dynegy Holdings Inc	(335)(1)	(335)(2)	(221)(3)	(362)(4)

(1) Includes goodwill impairment charges of $433 million. Please read Note 15—Goodwill for further discussion. Includes impairment charges of $5 million (discontinued operations) related to the assets included in the LS Power Transactions. Please read Note 6—Impairment Charges for further discussion.
(2) Includes impairment charges of $179 million (continuing operations) and $18 million (discontinued operations) related to the assets included in the LS Power Transactions and $208 million related to Roseton and Danskammer. Please read Note 6—Impairment Charges for further discussion.
(3) Includes impairment charges of $147 million (continued operations) and $235 million (discontinued operations) related to the assets included in the LS Power sale and $1 million related to Roseton and Danskammer. Please read Note 6—Impairment Charges for further discussion.
(4) Includes pre-tax charges of $312 million related to the sale of assets to LS Power. This charge is comprised of $124 million included in Gain (loss) on sale of assets, $104 million included in Income (loss) from discontinued operations and $84 million included in Losses from unconsolidated investments. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions—LS Power Transactions for further discussion. In addition, includes $46 million debt extinguishment costs for the 2011 and 2012 senior unsecured debt repayment. Please read Note 17—Debt—Credit Facility for further discussion.

	Quarter Ended			
	March 2008	June 2008	September 2008	December 2008
	(in millions, except per share data)			
Revenues	$ 530	$ 261	$ 1,759	$ 774
Operating income (loss)	(130)	(354)	1,063	165
Net income (loss)	(153)	(271)	605 (1)	24(2)
Net income (loss) attributable to Dynegy Holdings Inc.	(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 6—Impairment Charges—Asset Impairments for further information. Includes translation gains related to the substantial liquidation of a foreign entity of $24 million.

Schedule I

DYNEGY INC.

CONDENSED BALANCE SHEETS OF THE REGISTRANT
(in millions)

		December 31, 2009		December 31, 2008
ASSETS				
Current Assets				
Cash and cash equivalents	$	52	$	22
Intercompany accounts receivable		—		534
Short term investments		1		1
Deferred income taxes		6		6
Total Current Assets		59		563
Other Assets				
Investments in affiliates		6,391		7,369
Unconsolidated investments		—		15
Deferred income taxes		—		—
Total Assets	$	6,450	$	7,947
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities				
Accounts payable	$	—	$	19
Intercompany accounts payable		524		2
Other current liabilities		—		1
Total Current Liabilities		524		22
Intercompany long-term debt		2,244		2,244
Deferred income taxes		780		1,166
Total Liabilities		3,548		3,432
Commitments and Contingencies (Note 2)				
Stockholders' Equity				
Class A Common Stock, $0.01 par value, 2,100,000,000 shares authorized at December 31, 2009 and December 31, 2008; 603,577,577 shares and 505,821,277 shares issued and outstanding at December 31, 2009 and December 31, 2008, respectively		6		5
Class B Common Stock, $0.01 par value, 850,000,000 shares authorized at December 31, 2009 and December 31, 2008 and 340,000,000 shares issued and outstanding at December 31, 2008		—		3
Additional paid-in capital		6,056		6,485
Subscriptions receivable		(2)		(2)
Accumulated other comprehensive loss, net of tax		(150)		(215)
Accumulated deficit		(2,937)		(1,690)
Treasury stock, at cost, 2,788,383 shares and 2,568,286 shares at December 31, 2009 and December 31, 2008, respectively		(71)		(71)
Total Stockholders' Equity		2,902		4,515
Total Liabilities and Stockholders' Equity	$	6,450	$	7,947

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

Schedule I

DYNEGY INC.

CONDENSED STATEMENTS OF OPERATIONS OF THE REGISTRANT
(in millions)

	Year Ended December 31, 2009	2008	2007
Operating loss	$ —	$ —	$ —
Earnings (losses) from unconsolidated investments	(1,684)	249	503
Other income and expense, net	1	1	3
Income (loss) before income taxes	(1,683)	250	506
Income tax (expense) benefit	436	(76)	(242)
Net income (loss)	$ (1,247)	$ 174	$ 264

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

Schedule I

DYNEGY INC.

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

	Year Ended December 31,		
	2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Operating cash flow, exclusive of intercompany transactions	$ (19)	$ —	$ 8
Intercompany transactions	3	3	46
Net cash provided by (used in) operating activities	(16)	3	54
CASH FLOWS FROM INVESTING ACTIVITIES:			
Unconsolidated investments	1	(16)	(10)
Business acquisitions, net of cash acquired	—	—	(128)
Short term investments	—	(2)	—
Net cash provided by (used in) investing activities	1	(18)	(138)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Dividends from affiliate	585	—	—
Redemption of capital stock	(540)	—	—
Proceeds from issuance of capital stock	—	2	4
Other financing, net	—	—	(6)
Net cash provided by (used in) financing activities	45	2	(2)
Net increase (decrease) in cash and cash equivalents	30	(13)	(86)
Cash and cash equivalents, beginning of period	22	35	121
Cash and cash equivalents, end of period	$ 52	$ 22	$ 35
SUPPLEMENTAL CASH FLOW INFORMATION			
Taxes paid (net of refunds)	4	23	48
SUPPLEMENTAL NONCASH FLOW INFORMATION			
Shares acquired through exchange of DHI assets	97	—	—
Contribution of intangibles and related deferred income taxes to DHI	36	—	—
Contribution of the Sandy Creek Project to DHI	—	—	(16)
Other affiliate activity	(48)	—	—

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 21—Commitments and Contingencies of our consolidated financial statements.

Please read Note 17—Debt of our consolidated financial statements and Note 21—Commitments and Contingencies—Guarantees and Indemnifications of our consolidated financial statements for a discussion of our guarantees.

Note 3—Related Party Transactions

For a discussion of our related party transactions, please read Note 18—Related Party Transactions of our consolidated financial statements.

Schedule II

DYNEGY INC.

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2009, 2008 and 2007

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
2009					
Allowance for doubtful accounts	$ 22	$ —	$ —	$ —	$ 22
Allowance for risk-management assets (1)	—	—	—	—	—
Deferred tax asset valuation allowance	37	12	(14)	—	35
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) (3)	37
2007					
Allowance for doubtful accounts	$ 48	$ (3)	$ (21) (2)	$ (4)	$ 20
Allowance for risk-management assets (1)	—	11	—	—	11
Deferred tax asset valuation allowance	69	(6)	(1)	—	62

(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 a partial reversal of the allowance for doubtful accounts on a foreign entity as a result of a bankruptcy settlement, as such amount was collected.

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

Schedule II

DYNEGY HOLDINGS INC.

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2009, 2008 and 2007

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
2009					
Allowance for doubtful accounts	$ 20	$ —	$ —	$ —	$ 20
Allowance for risk-management assets (1)	—	—	—	—	—
Deferred tax asset valuation allowance	37	11	(14)	—	34
2008					
Allowance for doubtful accounts	$ 15	$ 5	$ —	$ —	$ 20
Allowance for risk-management assets (1)	11	—	(11)	—	—
Deferred tax asset valuation allowance	59	(2)	—	(20) (3)	37
2007					
Allowance for doubtful accounts	$ 48	$ (3)	$ (21) (2)	$ (9)	$ 15
Allowance for risk-management assets (1)	—	11	—	—	11
Deferred tax asset valuation allowance	66	(6)	(1)	—	59

(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 a partial reversal of the allowance for doubtful accounts on a foreign entity as a result of a bankruptcy settlement, as such amount was collected.

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

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