DYNEGY INC.
Form 8-K
September 28, 2009

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

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

Date of Report (Date of earliest event reported)
September 28, 2009

DYNEGY INC.

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

Delaware	001-33443	20-5653152
Delaware	000-29311	94-3248415
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

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

(713) 507-6400
(Registrant's telephone number, including area code)

N.A.
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

¨ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

¨ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

¨ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

¨ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On April 30, 2009, Dynegy Inc. (“Dynegy”) and Dynegy Holdings Inc. (“DHI”), collectively “we”, “us” or “our”, completed th sale of our interest in the Heard County power generation facility for approximately $105 million. We reported our operations with respect to the Heard County facility as a discontinued operation in our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2009 and June 30, 2009.

On January 1, 2009, we adopted SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51 (“SFAS No. 160”), 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. SFAS No. 160 also requires retrospective application of all disclosure requirements. We have reported the Plum Point Project’s third-party ownership interests as noncontrolling interests within our financial statements in our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2009 and June 30, 2009.

This Current Report on Form 8-K was prepared to provide updated financial information that (i) presents the Heard County facility as a discontinued operation and (ii) presents noncontrolling interests pursuant to SFAS No. 160 for all periods presented, as applicable in our Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009. It should be noted that Dynegy’s net income (loss) attributable to Dynegy Inc., or DHI’s net income (loss) attributable to Dynegy Holdings Inc., was not impacted by the reclassification of our operations with respect to the Heard County facility to discontinued operations. Furthermore, our adoption of SFAS No. 160 did not impact the Dynegy Inc.'s net income (loss) attributable to Dynegy Inc. common stockholders.

This report includes the combined filing of Dynegy and DHI. Unless the context indicates otherwise, throughout this report on Form 8-K, the terms “the Company”, “we”, “us”, “our” and “ours” are used to refer to both Dynegy and DHI and thei 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.

Please note that we have not otherwise updated our financial information or business discussion for activities or events occurring after the date this information was presented in our 2008 Form 10-K, except for discloure of certain significant subsequent events in Note 25—Subsequent Events. You should read our Quarterly Reports on Form 10-Q for the periods ended March 31, 2009 and June 30, 2009, respectively, and our Current Reports on Form 8-K and any amendments thereto filed since our 2008 Form 10-K, for updated information.

This filing includes updated information for the following items included in our 2008 Form 10-K:

Item 6. Selected Financial Data

Item 7. Management’s Discussion and Analysis

Item 8. Financial Statements and Supplementary Data

Unaffected items of our 2008 Form 10-K have not been repeated in this Form 8-K.

Cross references that are included in the above items and that refer to information included on page numbers that are preceded by an "F" refer to the corresponding page included in this filing. Other cross references are to pages in our 2008 Form 10-K.

Item 6. Selected Financial Data

The selected financial information presented below was derived from, and is qualified by reference to, our Consolidated Financial Statements, including the notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial Statements and related notes and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Dynegy's Selected Financial Data

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$3,543	$3,092	$1,761	$2,010	$2,250
Depreciation and amortization expense	(367)	(320)	(212)	(204)	(216)
Impairment and other charges	—	—	(119)	(46)	(78)
General and administrative expenses	(157)	(203)	(196)	(468)	(330)
Operating income (loss)	756	605	105	(832)	(59)
Interest expense and debt conversion expense	(427)	(384)	(631)	(389)	(453)
Income tax (expense) benefit	(95)	(151)	152	393	155
Income (loss) from continuing operations	195	123	(321)	(800)	(153)
Income (loss) from discontinued operations (3)	(24)	148	(13)	895	141
Cumulative effect of change in accounting principles	—	—	1	(5)	—
Net income (loss)	$171	$271	$(333)	$90	$(12)
Net income (loss) attributable to Dynegy Inc. common stockholders	174	264	(342)	68	(37)
Basic earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders	$0.24	$0.15	$(0.72)	$(2.12)	$(0.47)
Basic net income (loss) per share attributable to Dynegy Inc. common stockholders	0.20	0.35	(0.75)	0.18	(0.10)
Diluted earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders	$0.24	$0.15	$(0.72)	$(2.12)	$(0.47)
Diluted net income (loss) per share attributable to Dynegy Inc. common stockholders	0.20	0.35	(0.75)	0.18	(0.10)
Shares outstanding for basic EPS calculation	840	752	459	387	378
Shares outstanding for diluted EPS calculation	842	754	509	513	504
Cash dividends per common share	$—	$—	$—	$—	$—
Cash Flow Data:					
Net cash provided by (used in) operating activities	$319	$341	$(194)	$(30)	$5
Net cash provided by (used in) investing activities	(102)	(817)	358	1,824	262
Net cash provided by (used in) financing activities	148	433	(1,342)	(873)	(115)

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

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	2008	2007	December 31, 2006 (in millions)	2005	2004
Balance Sheet Data (2):					
Current assets	$2,803	$1,663	$1,989	$3,706	$2,728
Current liabilities	1,702	999	1,166	2,116	1,802
Property and equipment, net	8,934	9,017	4,951	5,323	6,130
Total assets	14,213	13,221	7,537	10,126	9,843
Long-term debt (excluding current portion)	6,072	5,939	3,190	4,228	4,332
Notes payable and current portion of long-term debt	64	51	68	71	34
Series C convertible preferred stock	—	—	—	400	400
Capital leases not already included in long-term debt	4	5	6	—	—
Total equity	4,485	4,529	2,267	2,140	2,062

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

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

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

- 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).

Dynegy Holdings' Selected Financial Data

	Year Ended December 31, 2008	2007	2006	2005	2004
	(in millions, except per share data)				
Statement of Operations Data (1):					
Revenues	$3,543	$3,092	$1,761	$2,010	$1,448
Depreciation and amortization expense	(367)	(320)	(212)	(204)	(205)
Impairment and other charges	—	—	(119)	(40)	(24)
General and administrative expenses	(157)	(184)	(193)	(375)	(285)
Operating income (loss)	756	624	108	(733)	(195)
Interest expense and debt conversion expense	(427)	(384)	(579)	(383)	(332)
Income tax (expense) benefit	(143)	(116)	125	374	163
Income (loss) from continuing operations	229	183	(296)	(727)	(240)
Income (loss) from discontinued operations (2)	(24)	148	(12)	813	139
Cumulative effect of change in accounting principles	—	—	—	(5)	—

Net income (loss)	$205	$331	$(308)	$81	$(101)
Net income (loss) attributable to Dynegy Holdings Inc.	$208	$324	$(308)	$81	$(104)
Cash Flow Data:					
Net cash provided by (used in) operating activities	$319	$368	$(205)	$(24)	$(160)
Net cash provided by (used in) investing activities	(87)	(688)	357	1,839	(211)
Net cash provided by (used in) financing activities	146	369	(1,235)	(734)	289
Capital expenditures, acquisitions and investments	(626)	(350)	(155)	(169)	(219)

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	December 31,				
	2008	2007	2006	2005	2004
	(in millions)				
Balance Sheet Data (1):					
Current assets	$2,780	$1,614	$1,828	$3,457	$2,192
Current liabilities	1,681	999	1,165	2,212	1,773
Property and equipment, net	8,934	9,017	4,951	5,323	6,130
Total assets	14,174	13,107	8,136	10,580	10,129
Long-term debt (excluding current portion)	6,072	5,939	3,190	4,003	4,107
Notes payable and current portion of long-term debt	64	51	68	191	34
Capital leases not already included in long-term debt	4	5	6	—	—
Total equity	4,583	4,620	3,036	3,331	3,191

(1) The Contributed Entities' assets were contributed to DHI contemporaneously with the Merger. This contribution was accounted for as a transaction between entities under common control. As such, the assets and liabilities were recorded by DHI at Dynegy's historical cost on Dynegy's date of acquisition.

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

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

- 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

We have updated Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 8-K to provide updated financial information that (i) presents the Heard County facility as a discontinued operation and (ii) presents noncontrolling interests pursuant to SFAS No. 160 for all periods presented, as applicable in our Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009. We have not otherwise updated our financial information or business discussion in this Item 7 for activities or events occurring after the date this information was presented in our 2008 Form 10-K. You should read our Quarterly Reports on Form 10-Q for the periods ended March 31, 2009 and June 30, 2009, respectively, and our Current Reports on Form 8-K and any amendments thereto filed since our 2008 Form 10-K, for updated information.

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

OVERVIEW

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

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

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

Business Discussion

Power Generation Business

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

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

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

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

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

- Transmission constraints, congestion, and other factors that can affect the price differential between the locations where we deliver generated power and the liquid market hub;

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

- Overall electricity demand patterns;

- Our ability to optimize our assets by maintaining a high in-market availability, reliable run-time and safe, efficient operations; and

- The cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive.

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

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

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

- Our ability to maintain sufficient coal inventories, which is dependent upon the continued performance of the railroads for deliveries of coal in a consistent and timely manner, and its impact on our ability to serve the critical winter and summer on-peak loads;

- Our requirement for the next four years to utilize a significant amount of cash for capital expenditures required to comply with the Consent Decree;

- Changes in the MISO market design or associated rules; and

- Changes in the existing PJM RPM capacity markets or in the bilateral MISO capacity markets and any resulting effect on future capacity revenues.

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

- Our ability to maintain the necessary permits to continue to operate our Moss Landing power generation facility with a once-through, seawater cooling system;

- Our ability to maintain and operate our plants in a manner that ensures we receive full capacity payments under our various tolling agreements; and

- The economic life of our facilities, which could be adversely impacted by contractual obligations, regulatory actions or other factors.

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

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

- State-driven programs aimed at capping mercury and CO2 emissions will impose additional costs on our power generation facilities.

Other

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

- Interest expense, which reflects debt with a weighted-average rate of approximately 7 percent;

- General and administrative costs, which will be impacted by, among other things, (i) staffing levels and associated expenses; (ii) funding requirements under our pension plans; and (iii) any future corporate-level litigation reserves or settlements; and

- Income taxes, which will be impacted by our ability to realize our significant alternative minimum tax credits.

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

2008 Highlights

DLS Power Holdings and DLS Power Development Dissolution. Effective January 1, 2009, Dynegy entered into an agreement with LS Associates to dissolve DLS Power Holdings and DLS Power Development, our development joint ventures with LS Power Associates. Under the terms of this agreement, we acquired exclusive rights related to repowering and expansion opportunities at our existing facilities. In return, LS Power Associates received a cash payment of approximately $19 million, as well as full rights to new greenfield development opportunities previously held by the joint venture. As a result of this agreement, we recorded a $71 million pre-tax charge related to our investment in the joint ventures, which consisted of a $24 million impairment and a $47 million loss on dissolution. This dissolution has no effect on our ownership rights in the Plum Point or Sandy Creek projects. Please read Note 13—Variable Interest Entities—DLS Power Holdings and DLS Power Development for further discussion.

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

Contingent LC Facility. On June 17, 2008, DHI entered into the Contingent LC Facility with Morgan Stanley. Availability under the Contingent LC Facility is contingent on natural gas prices rising above $13/MMBtu during 2009. In the event that the Contingent LC Facility is utilized, it will complement existing liquidity instruments as a source of additional letters of credit to meet our collateral requirements. Such letters of credit will be available for the purpose of supporting certain commercial and trading contracts and related netting agreements described in the Credit Agreement. Please read Note 16—Debt—Contingent LC Facility for further discussion.

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

LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, collateral requirements, fixed capacity payments and contractual obligations, capital expenditures (including required environmental expenditures), potential funding commitments for our equity investment and working capital needs. Examples of working capital needs include purchases of commodities, particularly natural gas and coal, facility maintenance costs and other costs such as payroll.

Our primary sources of internal liquidity are cash flows from operations, cash on hand, available capacity under our Credit Agreement, of which the revolver capacity of $1,080 million is scheduled to mature in April 2012 and the term letter of credit capacity of $850 million is scheduled to mature in April 2013, and available capacity under our Contingent LC Facility, as described further below. Our primary sources of external liquidity are asset sales proceeds and proceeds from capital market transactions to the extent we engage in these transactions. Operating cash flows provided by our power generation assets and the available cash we currently hold are expected to be sufficient to fund the operation of our business, as well as our planned capital expenditure program, including expenditures in connection with the Consent Decree, and debt service requirements over the next twelve months. We maintain capacity under the Credit Agreement in order to post collateral in the form of letters of credit or cash, and we believe we have sufficient capacity should we be required to post additional collateral. Please read Note 16—Debt—Fifth Amended and Restated Credit Facility for a discussion of the financial covenants contained in the Credit Agreement, as well as the discussion below regarding our Revolver Capacity. Additionally, DHI may borrow money from time to time from Dynegy.

Market Conditions

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

- Lehman Commercial Paper Inc. ("Lehman CP"), a lender under our Credit Agreement, entered bankruptcy proceedings. As a result, our effective availability under the Credit Agreement may be reduced by $70 million to $1.9 billion;

- We recorded a reserve of $3 million as a result of the bankruptcy of LBH. This reserve represents the uncollateralized portion of our $15 million net position arising from our outstanding commercial transactions with a subsidiary of LBH;

- A large money market fund in which we invested a portion of our cash balance lowered its share price below $1, subsequently suspended distributions and commenced liquidation. As a result, we reclassified our $127 million investment from cash equivalents to short-term investments and recorded a $2 million impairment. We have received approximately $100 million of distributions as of December 31, 2008; and

- A decrease in liquidity in the bilateral markets for forward power sales, resulting in increased exchange-traded transactions settling through our futures clearing manager that can potentially result in the need for additional cash collateral postings.

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

Also, as a result of the recent decline in the overall capital markets, the value of our pension plan assets has decreased as of December 31, 2008. Please read Note 22—Employee Compensation, Savings and Pension Plan—Pension and Other Post-Retirement Benefits for further discussion.

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Corporate Matters

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

- continue to hold their 40 percent investment in Dynegy;

- make an offer to purchase all of the outstanding shares of Dynegy's common stock. Upon such offer, we may either (i) accept the offer or (ii) if requested by the LS Entities, conduct an auction of Dynegy in which the LS Entities may elect whether or not to participate; or

- freely transfer (i.e. sell) their shares of Dynegy's Class B common stock to any person so long as such transfer would not result in such person owning more than 15 percent of the outstanding shares of Dynegy's common stock.

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

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

(1) Lehman CP filed for protection from creditors under the bankruptcy law in October 2008, thus potentially reducing the available capacity of the revolving portion of the Credit Agreement by $70 million. Please read Note 16—Debt—Credit Agreement for further discussion. We continue to believe that we maintain sufficient liquidity despite any such reduction in the available capacity under the revolving portion of our Credit Agreement.

(2) We currently have 15 lenders participating in the revolving portion of our Credit Agreement with commitments ranging from $10 million to $105 million. Other than the commitment from Lehman CP, we have not experienced, nor do we currently anticipate, any difficulties in obtaining funding from any of the remaining lenders at this time. However, we continue to monitor the environment, and any lack of or delay in funding by a significant member or multiple members of our banking group could negatively affect our liquidity position.

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

(4)

Under the terms of the Contingent LC Facility, up to $300 million of capacity can become available, contingent on 2009 forward natural gas prices rising above $13/MMBtu. Over the course of 2009, the ratio of availability per dollar increase in natural gas prices will be reduced, on a pro rata monthly basis, to zero by year-end.

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

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

Revolver Capacity. On April 2, 2007, DHI entered into the Fifth Amended and Restated Credit Facility, which is our primary credit facility. On May 24, 2007, DHI entered into an amendment to the Fifth Amended and Restated Credit Facility. As of February 20, 2009, $1,104 million in letters of credit are outstanding but undrawn, and we have no revolving loan amounts drawn under the Fifth Amended and Restated Credit Facility. The Fifth Amended and Restated Credit Facility has financial covenants which could restrict our ability to realize full capacity utilization based on levels of realized EBITDA, all as defined in Section 7.11 of the Fifth Amended and Restated Credit Facility. Based on management's current forecast of financial performance during 2009, DHI's available liquidity under the Fifth Amended and Restated Facility may be reduced temporarily in order to remain in compliance with the secured debt to adjusted EBITDA ratio. Please read Note 16—Debt—Fifth Amended and Restated Credit Facility for further discussion of our amended credit facility.

Operating Activities

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

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

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

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

Collateral Postings. We use a significant portion of our capital resources, in the form of cash and letters of credit, to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The following table summarizes our consolidated collateral postings to third parties by line of business at February 20, 2009, December 31, 2008 and December 31, 2007:

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

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

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

Going forward, we expect counterparties' collateral demands to continue to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their views of our creditworthiness. We believe that we have sufficient capital resources to satisfy counterparties' collateral demands, including those for which no collateral is currently posted, for the foreseeable future.

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

Investing Activities

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

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

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

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

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

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

If the costs of these capital expenditures become great enough to render the operation of the affected facility or facilities uneconomical, we could, at our option, cease to operate the facility or facilities and forego these capital expenditures without incurring any further obligations under the Consent Decree. Please read Note 20—Commitments and Contingencies—Other Commitments and Contingencies—Midwest Consent Decree for further discussion.

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

Please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Disclosure of Contractual Obligations and Contingent Financial Commitments—Off-Balance Sheet Arrangements—DNE Leveraged Lease for further discussion of early lease termination payments. Please read Note 20—Commitments and Contingencies—Legal Proceedings—Roseton State Pollutant Discharge Elimination System Permit and —Commitments and Contingencies—Legal Proceedings—Moss Landing National Pollutant Discharge Elimination System Permit for further discussion.

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

On February 25, 2009, we entered into an agreement to sell our interest in the Heard County power generation facility to Oglethorpe. This transaction closed on April 30, 2009. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—Heard County for further discussion.

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

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

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

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

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

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

Financing Activities

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

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

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

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

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

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

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

Total notes payable and long-term debt (4)	$6,136	$ 5,990

(1) Includes PPEA's non-recourse project financing of $515 million and tax-exempt bonds of $100 million for its share of the construction of the Plum Point facility. Although we own a 37 percent economic interest in PPEA, we consolidate PPEA and its debt, as we are the primary beneficiary of this VIE. Also includes project financing associated with our Independence facility. Please read Note 13—Variable Interest Entities for further discussion.
(2) Represents present value of future lease payments discounted at 10 percent.
(3) Consists of net premiums on debt of $13 million and $19 million at December 31, 2008 and 2007, respectively.
(4) Does not include letters of credit.

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

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

In September 2008, LBH filed for protection from creditors under Chapter 11 bankruptcy law. Lehman CP, the Lehman entity acting as one of our lenders for the revolving portion of our Credit Agreement, was not initially part of the bankruptcy estate. However, in early October 2008, Lehman CP also filed for protection from creditors under the bankruptcy law. Lehman CP’s lending obligations were not assumed by Barclays, which had acquired most of Lehman’s North American banking operations in September 2008. The bankruptcy filing increases the likelihood that Lehman CP will not fund any borrowing requests under our Credit Agreement, thereby reducing our effective availability under the Credit Agreement by $70 million to $1.9 billion.

Please read Note 16—Debt for further discussion of these items. Following these transactions, our debt maturity profile as of December 31, 2008 includes $64 million in 2009, $68 million in 2010, $575 million in 2011, $582 million in 2012, $1,004 million in 2013 and approximately $3,843 million thereafter. Maturities for 2009 represent principal payments on the Sithe Senior Notes.

Financing Trigger Events. Our debt instruments and other financial obligations include provisions, which, if not met, could require early payment, additional collateral support or similar actions. These trigger events include leverage ratios and other financial covenants, insolvency events, defaults on scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events, although certain interest rate swaps to which Plum Point is a party could be terminated if a credit downgrade of Plum Point occurs and there is also a default by the insurer that has provided credit insurance for the swaps.

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

Subject to certain exceptions, DHI and its relevant subsidiaries are subject to restrictions on asset sales incurring additional indebtedness, limitations on investments and certain limitations on dividends and other payments in respect of capital stock. Our lenders agreed to amend certain of these restrictions or limitations effective as of February 13, 2009. Based on our available liquidity as of December 31, 2008 and the additional capacity available under the Contingent LC Facility, we do not believe these limitations will affect our liquidity. Please read Note 16—Debt—Fifth Amended and Restated Credit Facility for further discussion of our amended credit facility.

Capital-Raising Transactions. As part of our ongoing efforts to maintain a capital structure that is closely aligned with the cash-generating potential of our asset-based business, which is subject to cyclical changes in commodity prices, we may explore additional sources of external liquidity. The timing of any transaction may be impacted by events, such as strategic growth opportunities, legal judgments or regulatory requirements, which could require us to pursue additional capital in the near term. The receptiveness of the capital markets to an offering of debt or equity securities cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control, including current market conditions. Any issuance of equity by Dynegy likely would have other effects as well, including stockholder dilution. Our ability to issue debt securities is limited by our financing agreements, including the Credit Agreement, as amended. Please read Note 16—Debt for further discussion.

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

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

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

Credit Ratings

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

Disclosure of Contractual Obligations and Contingent Financial Commitments

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

Contractual Obligations

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

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

Long-Term Debt (Including Current Portion). Total amounts of Long-term debt (including current portion) are included in the December 31, 2008 consolidated balance sheet. Please read Note 16—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 16—Debt for further discussion.

Operating Leases. Operating leases includes the minimum lease payment obligations associated with our DNE leveraged lease. Please read "—Liquidity and Capital Resources—Off-Balance Sheet Arrangements—DNE Leveraged Lease" for further discussion. Amounts also include minimum lease payment obligations associated with office and office equipment leases.

In addition, we are party to two charter party agreements relating to two VLGCs previously utilized in our former global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $14 million each year for the years 2009 through 2012, and approximately $17 million from 2013 through lease expiration. The charter party rates payable under the two charter party agreements vary in accordance with market-based rates for similar shipping services. The $14 million and $17 million amounts set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary terms of the charter party agreements expire September 2013 and September 2014, respectively. On January 1, 2003, in connection with the sale of our global liquids business, we sub-chartered both VLGCs to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. We continue to rely on the sub-charters with a subsidiary of Transammonia to satisfy the obligations of our two charter party agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements.

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

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

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

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

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

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

Other Obligations. Other obligations include the following items:

- A payment of $8.5 million in 2009 related to Illinois rate relief legislation. Please read Note 20—Commitments and Contingencies—Illinois Auction Complaints for further discussion;
- Payments associated with a capacity contract between Independence and Con Edison. The aggregate payments through the 2014 expiration are approximately $13 million as of December 31, 2008;
- $6 million of reserves recorded in connection with FIN No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN No. 48"). Please read Note 18—Income Taxes—Unrecognized Tax Benefits for further discussion;
- Amounts related to a long-term coal agreement to assist in the delivery of coal to our Danskammer plant in Newburgh, New York. The agreement extends until 2010, and the minimum aggregate payments through expiration total approximately $7 million as of December 31, 2008; and
- Agreements for the supply of water to our generating facilities.

Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2008 on an undiscounted basis. These obligations represent contingent obligations that may require a payment of cash upon the occurrence of specified events.

	Expiration by Period				
	Total	Less than 1 Year	1–3 Years	3-5 Years	More than 5 Years
			(in millions)		
Letters of credit (1)	$1,135	$835	$300	$—	$—
Surety bonds (2)	7	7	—	—	—
Total financial commitments	$1,142	$842	$300	$—	$—

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

Off-Balance Sheet Arrangements

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

As of December 31, 2008, future lease payments are $141 million for 2009, $95 million for 2010, $112 million for 2011, $179 million for 2012, $142 million for 2013, $143 million for 2014 and $248 million in the aggregate due from 2015 through lease expiration. The Roseton lease expires on February 8, 2035 and the Danskammer lease expires on May 8, 2031. We have no option to purchase the leased facilities at the end of their respective lease terms. DHI has guaranteed the lessees' payment and performance obligations under their respective leases on a senior unsecured basis. At December 31, 2008, the present value (discounted at 10 percent) of future lease payments was $700 million.

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

	2008	2007	2006
		(in millions)	
Lease Expense	$50	$50	$50
Lease Payments (Cash Flows)	$144	$107	$60

If one or more of the leases were to be terminated because of an event of loss, because it had become illegal for the applicable lessee to comply with the lease or because a change in law had made the facility economically or technologically obsolete, DHI would be required to make a termination payment in an amount sufficient to compensate the lessor for termination of the lease, including redeeming the pass-through trust certificates related to the unit or facility for which the lease was terminated at par plus accrued and unpaid interest. As of December 31, 2008, the termination payment at par would be approximately $930 million for all of the leased facilities, which exceeds the $920 million we received on the sale of the facilities. If a termination of this type were to occur with respect to all of the leased facilities, it would be difficult for DHI to raise sufficient funds to make this termination payment. Alternatively, if one or more of the leases were to be terminated because we determine, for reasons other than as a result of a change in law, that it has become economically or technologically obsolete or that it is no longer useful to our business, DHI must redeem the related pass-through trust certificates at par plus a make-whole premium in an amount equal to the discounted present value of the principal and interest payments still owing on the certificates being redeemed less the unpaid principal amount of such certificates at the time of redemption. For this purpose, the discounted present value would be calculated using a discount rate equal to the yield-to-maturity on the most comparable U.S. Treasury security plus 50 basis points.

Commitments and Contingencies

Please read Note 20—Commitments and Contingencies, which is incorporated herein by reference, for further discussion of our material commitments and contingencies.

RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the years ended December 31, 2008, 2007 and 2006. At the end of this section, we have included our business outlook for each segment.

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

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

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

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$1,623	$919	$1,006	$(5)	$3,543
Cost of sales	(584)	(574)	(705)	10	(1,853)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(205)	(122)	(180)	15	(492)
Depreciation and amortization expense	(206)	(97)	(54)	(10)	(367)
Impairment and other charges	—	—	—	—	—
Gain on sale of assets	56	11	—	15	82
General and administrative expense	—	—	—	(157)	(157)
Operating income (loss)	$684	$137	$67	$(132)	$756
Losses from unconsolidated investments	—	(40)	—	(83)	(123)
Other items, net	—	5	6	73	84
Interest expense					(427)
Income from continuing operations before income taxes					290
Income tax expense					(95)
Income from continuing operations					195
Loss from discontinued operations, net of taxes					(24)
Net income					171
Less: Net loss attributable to the noncontrolling interests					(3)

Net income attributable to Dynegy Inc.	$174

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

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$ 1,325	$ 678	$ 1,076	$ 13	$ 3,092
Cost of sales	(482)	(396)	(688)	19	(1,547)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(193)	(84)	(179)	(4)	(460)
Depreciation and amortization expense	(194)	(68)	(45)	(13)	(320)
Gain on sale of assets	39	—	—	4	43
General and administrative expense	—	—	—	(203)	(203)
Operating income (loss)	$ 495	$ 130	$ 164	$ (184)	$ 605
Earnings (losses) from unconsolidated investments	—	6	—	(9)	(3)
Other items, net	—	—	—	56	56
Interest expense					(384)
Income from continuing operations before income taxes					274
Income tax expense					(151)
Income from continuing operations					123
Income from discontinued operations, net of taxes					148
Net income					271
Less: Net income attributable to the noncontrolling interests					7
Net income attributable to Dynegy Inc.					$ 264

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

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$969	$78	$609	$105	$1,761
Cost of sales	(318)	(64)	(370)	(44)	(796)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(165)	(4)	(160)	(7)	(336)
Depreciation and amortization expense	(168)	(3)	(24)	(17)	(212)
Impairment and other charges	(110)	(9)	—	—	(119)
Gain on sale of assets	—	—	—	3	3
General and administrative expense	—	—	—	(196)	(196)
Operating income (loss)	$208	$(2)	$55	$(156)	$105
Losses from unconsolidated investments	—	(1)	—	—	(1)
Other items, net	2	1	9	42	54
Interest expense and debt conversion costs					(631)
Loss from continuing operations before income taxes					(473)
Income tax benefit					152
Loss from continuing operations					(321)
Loss from discontinued operations, net of taxes					(13)
Cumulative effect of change in accounting principle, net of taxes					1
Net loss attributable to Dynegy Inc.					$(333)

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

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

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$1,623	$919	$1,006	$(5)	$3,543
Cost of sales	(584)	(574)	(705)	10	(1,853)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(205)	(122)	(180)	15	(492)
Depreciation and amortization expense	(206)	(97)	(54)	(10)	(367)
Impairment and other charges	—	—	—	—	—
Gain on sale of assets	56	11	—	15	82
General and administrative expense	—	—	—	(157)	(157)
Operating income (loss)	$684	$137	$67	$(132)	$756
Losses from unconsolidated investments	—	(40)	—	—	(40)
Other items, net	—	5	6	72	83
Interest expense					(427)
Income from continuing operations before income taxes					372
Income tax expense					(143)
Income from continuing operations					229
Loss from discontinued operations, net of taxes					(24)
Net income					205
Less: Net loss attributable to the noncontrolling interests					(3)
Net income attributable to Dynegy Holdings Inc.					$208

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

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Revenues	$1,325	$678	$1,076	$13	$3,092
Cost of sales	(482)	(396)	(688)	19	(1,547)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(193)	(84)	(179)	(4)	(460)
Depreciation and amortization expense	(194)	(68)	(45)	(13)	(320)
Gain on sale of assets	39	—	—	4	43
General and administrative expense	—	—	—	(184)	(184)
Operating income (loss)	$495	$130	$164	$(165)	$624
Earnings from unconsolidated investments	—	6	—	—	6
Other items, net	—	—	—	53	53
Interest expense					(384)
Income from continuing operations before income taxes					299
Income tax expense					(116)
Income from continuing operations					183
Income from discontinued operations, net of taxes					148
Net income					331
Less: Net income attributable to the noncontrolling interests					7
Net income attributable to Dynegy Holdings Inc.					$324

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

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
	(in millions)				
Revenues	$969	$78	$609	$105	$1,761
Cost of sales	(318)	(64)	(370)	(44)	(796)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(165)	(4)	(160)	(7)	(336)
Depreciation and amortization expense	(168)	(3)	(24)	(17)	(212)
Impairment and other charges	(110)	(9)	—	—	(119)
Gain on sale of assets	—	—	—	3	3
General and administrative expense	—	—	—	(193)	(193)
Operating income (loss)	$208	$(2)	$55	$(153)	$108
Losses from unconsolidated investments	—	(1)	—	—	(1)
Other items, net	2	1	9	39	51
Interest expense and debt conversion costs					(579)
Loss from continuing operations before income taxes					(421)
Income tax benefit					125
Loss from continuing operations					(296)
Loss from discontinued operations, net of taxes					(12)
Net loss attributable to Dynegy Holdings Inc.					$(308)

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

	Year Ended December 31,					
	2008		2007		2006	
GEN-MW						
Million Megawatt Hours Generated	24.5		25.0		21.5	
In Market Availability for Coal Fired Facilities (1)	90	%	93	%	89	%
Average Capacity Factor for Combined Cycle Facilities (2)	16	%	19	%	—	
Average Quoted On-Peak Market Power Prices ($/MWh) (3):						
Cinergy (Cin Hub)	$67		$61		$52	
Commonwealth Edison (NI Hub)	$66		$59		$52	
PJM West	$84		$71		$62	
Average On-Peak Market Spark Spreads ($/MWh) (4):						
PJM West	15		17		10	
GEN-WE						
Million Megawatt Hours Generated (5) (6)	11.2		11.0		0.9	
Average Capacity Factor for Combined Cycle Facilities (2)	44	%	59	%	—	
Average Quoted On-Peak Market Power Prices ($/MWh) (3):						
North Path 15 (NP 15)	$80		$67		$61	
Palo Verde	$72		$62		$58	
Average On-Peak Market Spark Spreads ($/MWh) (4):						
North Path 15 (NP 15)	$18		$16		$14	
Palo Verde	$13		$13		$12	
GEN-NE						
Million Megawatt Hours Generated	7.9		9.4		4.4	
In Market Availability for Coal Fired Facilities (1)	91	%	90	%	86	%
Average Capacity Factor for Combined Cycle Facilities (2)	25	%	37	%	17	%
Average Quoted On-Peak Market Power Prices ($/MWh) (3):						
New York—Zone G	$101		$84		$76	
New York—Zone A	$68		$64		$59	
Mass Hub	$91		$78		$70	
Average On-Peak Market Spark Spreads ($/MWh) (4):						
New York—Zone A	$3		$12		$9	
Mass Hub	$23		$23		$19	
Fuel Oil	$(37	)	$(16	)	$(10	)
Average natural gas price—Henry Hub ($/MMBtu) (7)	$8.85		$6.95		$6.74	

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

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

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

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

(5) Includes our ownership percentage in the MWh generated by our GEN-WE investment in the Black Mountain power generation facility for the years ended December 31, 2008, 2007 and 2006, respectively.
(6) Excludes approximately 1.8 million MWh and 2.9 million MWh generated by our CoGen Lyondell power generation facility, which we sold in August 2007, for the years ended December 31, 2007 and 2006 and less than 0.1 million MWh generated by our Calcasieu and Heard County power generation facilities, which we sold on March 31, 2008 and April 30, 2009, respectively, for the years ended December 31, 2008, 2007 and 2006.
(7) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by the Company.

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

	Year Ended December 31, 2008				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE (in millions)	Other	Total
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 ownership interest	—	13	—	—	13
Gain on liquidation of foreign entity	—	—	—	24	24
Sandy Creek mark-to-market losses (1)	—	(40)	—	—	(40)
Taxes (2)	—	—	—	12	12
Discontinued operations (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) Discontinued operations for GEN-WE includes a $47 million impairment of the Heard County power generation facility.

	Year Ended December 31, 2007				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Discontinued operations (1)	$—	$225	$—	$14	$239
Legal and settlement charges	—	—	—	(17)	(17)
Illinois rate relief charge	(25)	—	—	—	(25)
Change in fair value of interest rate swaps, net of minority interest	(9)	—	—	39	30
Gain on sale of Sandy Creek ownership interest	—	10	—	—	10
Gain on sale of Plum Point ownership interest	39	—	—	—	39
Settlement of Kendall toll	—	—	—	31	31
Taxes	—	—	—	30	30
Total—DHI	5	235	—	97	337
Legal and settlement charges	—	—	—	(19)	(19)
Taxes	—	—	—	(20)	(20)
Total—Dynegy	$5	$235	$—	$58	$298

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

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

Year Ended 2008 Compared to Year Ended 2007

Operating Income

Operating income for Dynegy was $756 million for the year ended December 31, 2008, compared to $605 million for the year ended December 31, 2007. Operating income for DHI was $756 million for the year ended December 31, 2008, compared to $624 million for the year ended December 31, 2007.

Our operating income for the year ended December 31, 2008 was driven, in part, by mark-to-market gains on forward sales of power associated with our generating assets, which are included in Revenues in the consolidated statements of operations. Such gains, which totaled $253 million for the year ended December 31, 2008, were a result of a decrease in forward market power prices or forward spark spreads during 2008 combined with greater outstanding notional amounts of forward positions compared to the same period in the prior year. Effective April 2, 2007, we chose to cease designating our commodity derivative instruments as cash flow hedges for accounting purposes. Please read Note 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 $684 million for the year ended December 31, 2008, compared to $495 million for the year ended December 31, 2007.

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

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

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

- Increased market prices – The average quoted on-peak prices in the Cin Hub and PJM West pricing regions (the liquid market hubs where our forward power sales occurred) increased from $61 and $71 per MWh, respectively, for the year ended December 31, 2007 to $67 and $84 per MWh, respectively, for the year ended December 31, 2008;

- Additional capacity sales of approximately $35 million, as a result of improved capacity prices for 2008 compared with 2007; and

- In 2007, we recorded a pre-tax charge of $25 million in Cost of sales to support a rate relief package for Illinois electric consumers.

These items were offset by the following:

- Decreased volumes – In spite of the addition of the Midwest plants acquired through the Merger on April 2, 2007, generated volumes decreased by 2 percent, from 25 million MWh for the year ended December 30, 2007, to 24.5 million MWh for the year ended December 31, 2008. The decrease in volumes was primarily driven by forced outages, lower off-peak volumes due to mild temperatures and transmission congestion as a result of flooding;

- Increased fuel costs, due largely to higher natural gas prices; and

- Wider basis differentials – In 2008, the price differential between the locations where we deliver generated power and the liquid market hubs where our forward power sales occurred was wider, in part due to congestion and transmission outages and regional weather differences, as compared to the same period in the prior year. These wider price differentials had a negative impact on our results as the price we received for delivered power at our physical delivery locations did not increase to the same extent as that of the liquid traded hubs.

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

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

Power Generation—West Segment. Operating income for GEN-WE was $137 million for the year ended December 31, 2008, compared to operating income of $130 million for the year ended December 31, 2007. Such amounts do not include results from the CoGen Lyondell, Calcasieu and Heard County power generation facilities, which have been classified as discontinued operations for periods presented prior to disposition.

Revenues for the year ended December 31, 2008 increased by $241 million compared to the year ended December 31, 2007, cost of sales increased by $178 million and operating and maintenance expense increased by $38 million, resulting in a net increase of $25 million. The increase was primarily driven by the following:

- Mark-to-market gains – GEN-WE's results for the year ended December 31, 2008 included mark-to-market gains of $51 million, compared to $44 million of mark-to-market gains for the year ended December 31, 2007. Of the $51 million in 2008 mark-to-market gains, $3 million of losses related to positions that settled in 2008, and the remaining $54 million related to positions that will settle in 2009 and 2010; and

- Increased volumes – Generated volumes were 11.2 million MWh for the year ended December 31, 2008, up from 11.0 million MWh for the year ended December 31, 2007. The volume increase was primarily driven by the West plants acquired on April 2, 2007, which provided total results, including operating expense, of $177 million for the year ended December 31, 2008, compared with $156 million for the same period in 2007, exclusive of mark-to-market amounts discussed above. Results for 2008 were negatively impacted by a forced outage and increased fuel costs due to higher natural gas prices.

In May 2008, we sold a beneficial interest in Oyster Creek Limited to General Electric for approximately $11 million, and recognized a gain on the sale of approximately $11 million, reflected in Gain on sale of assets in our consolidated statements of operations. Depreciation expense increased from $68 million for the year ended December 31, 2007 to $97 million for year ended December 31, 2008 primarily as a result of the addition of the acquired plants.

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

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

- Decreased spark spreads – Although on-peak market power prices in New York Zone A increased by 7 percent, Zone A spark spreads contracted as fuel prices rose at a greater rate than power prices;

- Decreased volumes – In spite of the addition of the Northeast plants acquired through the Merger on April 2, 2007, generated volumes decreased by 16 percent, from 9.4 million MWh for the year ended December 31, 2007 to 7.9 million MWh for the year ended December 31, 2008. The volumes added by the new Northeast plants were more than offset by declines due to decreased spark spreads and reduced dispatch opportunities as compared to the same period in the prior year;

- Decreased results from the Bridgeport and Casco Bay assets, which provided results of $42 million for the year ended December 31, 2008, compared with $90 million for the year ended December 31, 2007, exclusive of mark-to-market amounts discussed below. Although the Bridgeport and Casco Bay assets provided a full year of results in 2008 compared with nine months in 2007, volumes were down during the key summer months as a result of compressed spark spreads and reduced dispatch opportunities;

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Decreased capacity sales of approximately $15 million, exclusive of the Bridgeport and Casco Bay results discussed above, as a result of lower capacity prices for 2008 compared with 2007; and

- Increased fuel cost, due largely to higher coal prices for our Danskammer facility.

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

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

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

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

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

Earnings (Losses) from Unconsolidated Investments

Dynegy's losses from unconsolidated investments were $123 million for the year ended December 31, 2008 of which $83 million related to Dynegy's investment in DLS Power Development, included in Other. These losses included a $24 million impairment charge, a $47 million loss on dissolution as a result of our decision to dissolve this venture and $12 million of equity losses. GEN-WE recognized $40 million of losses related to its investment in the Sandy Creek Project. These losses were comprised of $53 million primarily associated with our share of the partnership's losses, partially offset by $13 million for our share of the gain on SCEA's sale of an 11 percent undivided interest in the Sandy Creek Project. The $53 million consisted of $40 million mark-to-market losses primarily related to interest rate swap contracts and $13 million of financing costs. Please read Note 13—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 13—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 Agreement. Included in interest expense for the year ended December 31, 2007 was approximately $24 million of mark-to-market income from interest rate swap agreements associated with the Plum Point Term Facility. Effective July 1, 2007, these agreements were designated as cash flow hedges. Also included in interest expense for the year ended December 31, 2007 was approximately $12 million of income from interest rate swap agreements, prior to being terminated that were associated with the portion of the debt repaid in late May 2007. The mark-to-market income included in interest expense for 2007 is offset by net losses of approximately $7 million in connection with the repayment of a portion of the project indebtedness assumed in connection with the Merger.

Income Tax Expense

Dynegy reported an income tax expense from continuing operations of $95 million for the year ended December 31, 2008, compared to an income tax expense from continuing operations of $151 million for the year ended December 31, 2007. The 2008 effective tax rate was 33 percent, compared to 55 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 $143 million for the year ended December 31, 2008, compared to an income tax expense from continuing operations of $116 million for the year ended December 31, 2007. The 2008 effective tax rate was 38 percent, compared to 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 From Discontinued Operations Before Taxes.

During the year ended December 31, 2008, Dynegy's pre-tax loss from discontinued operations was $43 million ($24 million after-tax). Dynegy's GEN-WE segment included a pre-tax loss of $47 million ($27 million after-tax) related to the impairment of our Heard County power generating facility offset by pre-tax income of $4 million ($3 million after-tax) related to the receipt of business interruption insurance proceeds in Dynegy's former NGL segment. During the year ended December 31, 2007, Dynegy's pre-tax income from discontinued operations was $239 million ($148 million after-tax). Dynegy's GEN-WE segment included $225 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities in addition to a pre-tax gain of $224 million associated with the completion of our sale of the CoGen Lyondell power generation facility. Dynegy's U.K. CRM business included income of $15 million, primarily related to a favorable settlement of a legacy receivable.

During the year ended December 31, 2008, DHI's pre-tax loss from discontinued operations was $43 million ($24 million after-tax). Dynegy's GEN-WE segment included a pre-tax loss of $47 million ($27 million after-tax) related to the impairment of our Heard County power generating facility offset by pre-tax income of $4 million ($3 million after-tax) related to the receipt of business interruption insurance proceeds in Dynegy's former NGL segment. During the year ended December 31, 2007, DHI's pre-tax income from discontinued operations was $240 million ($148 million after-tax). DHI's GEN-WE segment included $225 million from the operation of the CoGen Lyondell and Calcasieu power generation facilities in addition to a pre-tax gain of $224 million associated with the completion of our sale of the CoGen Lyondell power generation facility. DHI's U.K. CRM business included income of $15 million, primarily related to a favorable settlement of a legacy receivable.

Income Tax Expense From Discontinued Operations

We recorded an income tax benefit from discontinued operations of $19 million and an income tax expense of $91 million during the years ended December 31, 2008 and 2007, respectively. The effective rates for the years ended December 31, 2008 and 2007 was 44 percent and 38 percent, respectively.

Noncontrolling Interest

We recorded $3 million of noncontrolling interest income for the year ended December 31, 2008, compared with $7 million of noncontrolling interest expense recorded in 2007 related to Plum Point development project. 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.

Year Ended 2007 Compared to Year Ended 2006

Operating Income

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

Power Generation—Midwest Segment. Operating income for GEN-MW was $495 million for the year ended December 31, 2007, compared to $208 million for the year ended December 31, 2006. Operating income for 2007 included a $39 million pre-tax gain related to the partial sale of our ownership interest in PPEA Holdings. Operating income for

2006 included a $110 million pre-tax impairment charge related to the Bluegrass generation facility, due to changes in the market that resulted in economic constraints on the facility.

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

- Higher volumes – Generated volumes increased by 16 percent, up from 21.5 million MWh for the year ended December 31, 2006 to 25 million MWh for the year ended December 31, 2007;

- Increased market prices – The average quoted on-peak prices in Cin Hub pricing region increased from $52 per MWh for the year ended December 31, 2006 to $61 per MWh for the year ended December 31, 2007;

- Improved pricing as a result of the Illinois reverse power procurement auction – Beginning January 1, 2007, we began operating under two new energy product supply agreements with subsidiaries of Ameren Corporation through our participation in the Illinois reverse power procurement auction in 2006. Under these new agreements, we provide up to 1,400 MWh around the clock for prices of approximately $64.77 per megawatt-hour; and

- The addition of the new Midwest plants acquired through the Merger – The Kendall and Ontelaunee plants acquired on April 2, 2007 contributed to the increase in generated volumes and provided results of $62 million for the year ended December 31, 2007, exclusive of mark-to-market losses discussed below.

These items were offset by the following:

- Mark-to-market losses – GEN-MW's results for the year ended December 31, 2007 included mark-to-market losses of $36 million related to forward sales, compared to $15 million of mark-to-market gains for the year ended December 31, 2006. Of the $36 million in 2007 mark-to-market losses, $13 million related to previously recognized mark-to-market gains that settled in 2007, and the remaining $23 million related to positions that will settle in 2008 and beyond. Please read Note 7—Risk Management Activities, Derivatives and Financial Instruments—Accounting for Derivative Instruments and Hedging Activities—Cash Flow Hedges for a discussion of our decision to no longer designate derivative transactions as cash flow hedges beginning with the second quarter 2007; and

- A $25 million charge related to the Illinois rate relief package – In July 2007, we entered into agreements with various parties to make payments of up to $25 million in connection with legislation providing for rate relief for Illinois electric consumers. During September 2007, we made an initial payment of $7.5 million. During 2007, we recorded a pre-tax charge of $25 million, included as a cost of sales on our consolidated statements of operations.

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

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

Revenues for the year ended December 31, 2007 increased by $600 million compared to the year ended December 31, 2006, cost of sales increased by $332 million and operating and maintenance expense increased by $80 million, resulting in a net increase of $188 million. The increase was primarily driven by the following:

- The addition of the new West plants acquired through the Merger – Generated volumes were 11.0 million MWh for the year ended December 31, 2007, up from 0.9 million MWh for the year ended December 31, 2006. The volume increase was primarily driven by the new West plants, which provided total results of $156 million for the year ended December 31, 2007, exclusive of mark-to-market gains discussed below. The volume increase from the new West plants was slightly offset by a reduction due to the sale of the Rockingham generation facility in late 2006; and

- Mark-to-market gains – GEN-WE's results for the year ended December 31, 2007 included mark-to-market gains of $44 million related to heat rate call-options and forward sales agreements, compared to zero for the year ended December 31, 2006. Of the $44 million in 2007 mark-to-market gains, $15 million related to risk management liabilities acquired in the Merger that settled in 2007, and the remaining $29 million related to positions that will settle in 2008 and beyond. Please read Note 7—Risk Management Activities, Derivatives and Financial

Instruments—Accounting for Derivative Instruments and Hedging Activities—Cash Flow Hedges for a discussion of our decision to no longer designate derivative transactions as cash flow hedges beginning with the second quarter 2007.

Depreciation expense increased from $3 million for the year ended December 31, 2006 to $68 million for the year ended December 31, 2007 primarily as a result of the new West plants. In addition, during 2006, we recorded a $9 million impairment of our Rockingham facility, resulting from the announcement of our sale of the facility.

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

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

- Increased market prices and spark spreads – On peak market prices in New York Zone G and Zone A increased by 11 percent and 8 percent, respectively. Spark spreads widened due to higher power prices. Average market spark spreads increased 33 percent and 21 percent for New York Zone A and Mass Hub, respectively;

- Higher volumes, partially driven by the addition of the new Northeast plants acquired through the Merger – Generated volumes increased by 114 percent, up from 4.4 million MWh for the year ended December 31, 2006 to 9.4 million MWh for the year ended December 31, 2007. The volume increase was partially driven by the new Northeast plants. The Bridgeport and Casco Bay plants provided total results of $90 million for the year ended December 31, 2007, exclusive of mark-to-market losses discussed below. The volume increase was also a result of higher spark spreads and cooler weather in the first quarter 2007, which led to greater run times than in 2006; and

- A fuel oil inventory write-down of approximately $6 million was recorded in the year ended December 31, 2006.

These items were offset by the following:

- Mark-to-market losses – GEN-NE's results for the year ended December 31, 2007 included mark-to-market losses of $40 million related to forward sales, compared to losses of $26 million for the year ended December 31, 2006. Of the $40 million in 2007 mark-to-market losses, $32 million related to risk management assets acquired in the Merger that settled in 2007. The remaining $8 million related to positions that will settle in 2008 and beyond. Please read Note 7—Risk Management Activities, Derivatives and Financial Instruments—Accounting for Derivative Instruments and Hedging Activities—Cash Flow Hedges for a discussion of our decision to no longer designate derivative transactions as cash flow hedges beginning with the second quarter 2007; and

- Results were favorably impacted in 2006 by $12 million due to an opportunistic sale of emissions credits that were not required for near-term operations of our facilities. Similar sales of $10 million occurred in 2007.

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

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

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

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

Earnings (Losses) from Unconsolidated Investments

Dynegy's losses from unconsolidated investments were $3 million for the year ended December 31, 2007 compared to losses of $1 million for the year ended December 31, 2006. Earnings in 2007 included $10 million from the GEN-WE investment in the Sandy Creek largely due to its share of the gain on SCEA's sale of a 25 percent undivided interest in the Sandy Creek Project. Please read Note 13—Variable Interest Entities—Sandy Creek for further information. This income was partially offset by losses related to Dynegy's interest in DLS Power Holdings. Earnings in 2006 related to the GEN-WE investment in Black Mountain.

DHI's earnings from unconsolidated investments were $6 million for the year ended December 31, 2007, compared with losses of $1 million the year ended December 31, 2006. Earnings in 2007 included $10 million from the GEN-WE investment in the Sandy Creek largely due to its share of the gain on SCEA's sale of a 25 percent undivided interest in the Sandy Creek Project. Please read Note 13—Variable Interest Entities—Sandy Creek for further information. Earnings in 2006 related to the GEN-WE investment in Black Mountain.

Other Items, Net

Dynegy's other items, net totaled $56 million of income for the year ended December 31, 2007, compared to $54 million of income for the year ended December 31, 2006.

DHI's other items, net totaled $53 million of income for the year ended December 31, 2007, compared to $51 million of income for the year ended December 31, 2006.

Interest Expense

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

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

Income Tax (Expense) Benefit

Dynegy reported an income tax expense from continuing operations of $151 million for the year ended December 31, 2007, compared to an income tax benefit from continuing operations of $152 million for the year ended December 31, 2006. The 2007 effective tax rate was 55 percent, compared to 32 percent in 2006. The income tax expense in 2007 included a $4 million benefit resulting from the change in New York state tax law and a $3 million expense resulting from a net increase in tax reserves. Additionally, Dynegy realized a higher state income tax expense resulting from adjusting Dynegy's temporary differences to a higher overall effective state tax rate. The higher effective state tax rate was driven by changes in levels of business activity in states in which we do business and the higher state tax rates in the states in which the Contributed Entities are located. Excluding the impact of changes in levels of business activity and changes in company structure, the 2007 calculation would result in an effective tax rate of 36 percent.

DHI reported an income tax expense from continuing operations of $116 million for the year ended December 31, 2007, compared to an income tax benefit from continuing operations of $125 million for the year ended December 31, 2006. The 2007 effective tax rate was 39 percent, compared to 30 percent in 2006. The income tax expense in 2007 included a $14 million benefit resulting from the change in New York state tax law and a $16 million benefit resulting from the release of tax reserves. Additionally, DHI realized a higher state income tax expense resulting from adjusting DHI's temporary differences to a higher overall effective state tax rate. The higher effective state tax rate was driven by changes in levels of business activity in states in which we do business and the higher state tax rates in the states in which the Contributed Entities are located. Excluding the impact of changes in levels of business activity and changes in company structure, the 2007 calculation would result in an effective tax rate of 31 percent.

Discontinued Operations

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

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

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

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

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

Income Tax (Expense) Benefit From Discontinued Operations. Dynegy recorded an income tax expense from discontinued operations of $91 million during the year ended December 31, 2007, compared to an income tax benefit from discontinued operations of $10 million during the year ended December 31, 2006. The income tax expense in 2007 included a $9 million benefit from a net release of tax reserves. The effective tax rate was impacted by the $47 million of goodwill allocated to the CoGen Lyondell power generation facility upon its sale. As there was no tax basis in the goodwill, there were no tax benefits associated with the allocated goodwill.

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

Cumulative Effect of Change in Accounting Principles

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

Noncontrolling Interest

We recorded $7 million of noncontrolling interest expense related to Plum Point facility in the year ended December 31, 2007. The noncontrolling interest expense was primarily due to the mark-to-market interest income recorded during the three months ended June 30, 2007 related to the interest rate swap agreements associated with the Plum Point Credit Agreement. Please read “Interest Expense” above for further discussion.

Outlook

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

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

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

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

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

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

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

If the costs of these capital expenditures become great enough to render the operation of the affected facility or facilities uneconomical, we could, at our option, cease to operate the facility or facilities and forego these capital expenditures without incurring any further obligations under the Consent Decree. Please read Note 20—Commitments and Contingencies—Other Commitments and Contingencies—Consent Decree for further discussion.

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

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

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

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

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

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

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

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

SEASONALITY

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

CRITICAL ACCOUNTING POLICIES

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

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

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

Revenue Recognition and Valuation of Risk Management Assets and Liabilities

We earn revenue from our facilities in three primary ways: (i) sale of energy generated by our facilities; (ii) sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load; and (iii) sale of capacity. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative, as defined by SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended, ("SFAS No. 133"). Please read "Derivative Instruments—Generation" for further discussion of the accounting for these types of transactions.

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

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

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

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

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

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

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

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

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

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

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

Valuation of Tangible and Intangible Assets

We evaluate long-lived assets, such as property, plant and equipment and investments, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Factors we consider important, which could trigger an impairment analysis, include, among others:

- significant underperformance relative to historical or projected future operating results;
- significant changes in the manner of our use of the assets or the strategy for our overall business;
- significant negative industry or economic trends; and
- significant declines in stock value for a sustained period.

We assess the carrying value of our property, plant and equipment and intangible assets subject to amortization in accordance with SFAS No. 144. If an impairment is indicated, the amount of the impairment loss recognized would be determined by the amount the book value exceeds the estimated fair value of the assets. The estimated fair value may include estimates based upon discounted cash-flow projections, recent comparable market transactions or quoted prices to determine if an impairment loss is required. For assets identified as held for sale, the book value is compared to the estimated sales price less costs to sell. There is a significant amount of judgment involved in cash-flow estimates, including assumptions regarding market convergence, discount rates and capacity. The assumptions used by another party could differ significantly from our assumptions. Please read Note 6—Impairment Charges for discussion of impairment charges we recognized in 2008 and 2006.

We follow the guidance of APB 18, “The Equity Method of Accounting for Investments in Common Stock” (“APB 18”), SFAS No. 115, “Accounting for Certain Investments in Debt and Equity Securities” (“SFAS No. 115”), and EITF Issue 02-14, “Whether an Investor Should Apply the Equity Method of Accounting to Investments Other Than Common Stock” (“EITF 02-14”), when reviewing our investments. The book value of the investment is compared to the estimated fair value, based either on discounted cash flow projections or estimated market prices, if available, to determine if an impairment is required. We record a loss when the decline in value is considered other than temporary. Please read Note 13—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.

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

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

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

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

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

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

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

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

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

Accounting for Contingencies, Guarantees and Indemnifications

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

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

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

Please read Note 20—Commitments and Contingencies for further discussion of our commitments and contingencies.

Accounting for Asset Retirement Obligations

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

Please read Note 2—Summary of Significant Accounting Policies—Asset Retirement Obligations for further discussion of our accounting for AROs.

Accounting for Variable Interest Entities

We follow the guidance in FIN 46(R), "Consolidation of Variable Interest Entities", which requires that we evaluate certain entities to determine which party is considered the primary beneficiary of the entity and thus required to consolidate it in its financial statements. We are or have been an investor in several variable interest entities to which LS Associates, a related party, is also an investor. There is a significant amount of judgment involved in determining the primary beneficiary of an entity from a related party group. We have concluded that we are not and were not the primary beneficiary of these entities because a) we believe that LS Power is more closely associated with the entities, b) they own approximately 40 percent of Dynegy's outstanding common stock and c) they have three seats on Dynegy's Board of Directors. If different judgment was applied, we could be considered the primary beneficiary of some or all of these entities, which would significantly impact our financial condition and results of operations. Please read Note 13—Variable Interest Entities for further discussion of our accounting for our variable interest entities.

We are also an investor, with independent third parties, in PPEA. PPEA is a variable interest entity, and there is a significant amount of judgment involved in the analysis used to determine the primary beneficiary. The analysis includes assumptions about forecasted cash flows, construction costs, and plant performance. We have concluded that we are the primary beneficiary of PPEA and therefore consolidate the entity in our consolidated financial statements. If different judgment was applied, we may not be considered the primary beneficiary for this entity, which would significantly impact our financial condition, results of operations and cash flows.

Please read Note 13—Variable Interest Entities for further discussion of our accounting for our variable interest entities.

Accounting for Income Taxes

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

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

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

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

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

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

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

Please read Note 18—Income Taxes for further discussion of our accounting for income taxes, adoption of FIN No. 48 and change in our valuation allowance.

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

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

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

The expected long-term rate of return on pension plan assets is selected by taking into account the asset mix of the plans and the expected returns for each asset category. Based on these factors, our expected long-term rate of return as of January 1, 2009 and 2008 was 8.25 percent.

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

	Impact on PBO, December 31, 2008	Impact on 2009 Expense
	(in millions)	
Increase in Discount Rate—50 basis points	$ (14)	$ (2)
Decrease in Discount Rate—50 basis points	15	2
Increase in Expected Long-term Rate of Return—50 basis points	—	(1)
Decrease in Expected Long-term Rate of Return—50 basis points	—	1

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

Please read Note 22—Employee Compensation, Savings and Pension Plans for further discussion of our pension-related assets and liabilities.

RECENT ACCOUNTING PRONOUNCEMENTS

We adopted SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statement— an amendment to ARB No. 51” on January 1, 2009 and have applied the presentation and disclosure requirements retrospectively. Please read Note 1—Organization and Operations and Basis of Presentation—Basis of Presentation for further discussion of our adoption of SFAS No. 160. We adopted SFAS No. 157, “Fair Value Measurements” and SFAS No. 159, “The Fair Value Option for Financial Assets and Liabilities” on January 1, 2008. We adopted FIN No. 48, “Accounting for Uncertainty in Income Taxes” (“FIN No. 48”) on January 1, 2007. We adopted SFAS No. 123(R) and SFAS No. 154, “Accounting Changes and Error Corrections—A Replacement of APB Opinion No. 20 and SFAS No. 3”, on January 1, 2006 and SFAS No. 158 on December 31, 2006. We adopted EITF Issue 05-6, “Determining the Amortization Period for Leasehold Improvements”, and FSP FIN No. 45-3, “Application of FASB Interpretation No. 45 to Minimum Revenue Guarantees Granted to a Business or Its Owners”, on January 1, 2006. Please read Note 2—Summary of Significant Accounting Policies—Accounting Policies Not Yet Adopted for further discussion for accounting policies not yet adopted.

RISK-MANAGEMENT DISCLOSURES

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

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

(1) Our modeling methodology has been consistently applied.

(2) This amount consists of changes in value associated with fair value and cash flow hedges on debt.

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

Risk-Management Asset and Liability Disclosures

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

Net Risk-Management Asset and Liability Disclosures

	Total	2009	2010	2011	2012	2013	Thereafter
				(in millions)			
Mark-to-Market (1)	$(30)	$144	$19	$(15)	$(12)	$(13)	$(153)

Cash Flow (2)	(113)	158	23	(19)	(16)	(16)	(243)

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

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

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

Net Fair Value of Risk-Management Portfolio

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

(1) Price inputs obtained from actively traded, liquid markets for commodities.
(2) The market quotations and prices based on models categorization differs from the SFAS No. 157 categories of Level 1, Level 2 and Level 3 due to the application of the different methodologies. Please read Note 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.

DYNEGY INC. and DYNEGY HOLDINGS INC.

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Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.

We have audited the accompanying consolidated balance sheets of Dynegy Inc. as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' equity, comprehensive income (loss) and cash flows for the years then ended. Our audits also included the financial statement schedules listed in the Index on page F-1 as of and for the years ended December 31, 2008 and 2007. These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

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

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

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2009, except for the matters described in the Basis of Presentation section set forth in Note 1 related to the inclusion of Heard County in discontinued operations as further disclosed in Note 4 and the effects of the adoption of SFAS No. 160 as further disclosed in Note 5, as to which the date is September 28, 2009.

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Report of Independent Registered Public Accounting Firm

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

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

As discussed in Note 20, the Company is the subject of substantial litigation. The Company's ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies", that might result from the ultimate resolution of such matters.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2007, except for the effects of discontinued operations described in Note 4, as to which the date is May 14, 2007 for Calcasieu, February 28, 2008 for CoGen Lyondell and September 28, 2009 for Heard County, and except for the change in reportable segments described in Note 23, as to which the date is February 26, 2009

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholder
Dynegy Holdings Inc.

We have audited the accompanying consolidated balance sheets of Dynegy Holdings Inc. as of December 31, 2008 and 2007, and the related consolidated statements of operations, cash flows, comprehensive income (loss), and stockholder's equity for the years then ended. Our audits also included the financial statement schedule listed in the Index on page F-1 as of and for the years ended December 31, 2008 and 2007. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2009, except for the matters described in the Basis of Presentation section set forth in Note 1 related to the inclusion of Heard County in discontinued operations as further disclosed in Note 4 and the effects of the adoption of SFAS No. 160 as further disclosed in Note 5, as to which the date is September 28, 2009.

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Report of Independent Registered Public Accounting Firm

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

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

As discussed in Note 20, the Company is the subject of substantial litigation. The Company’s ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, “Accounting for Contingencies”, that might result from the ultimate resolution of such matters.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 16, 2007, except for the effects of discontinued operations described in Note 4, as to which the date is May 14, 2007 for Calcasieu, August 16, 2007 for CoGen Lyondell and September 28, 2009 for Heard County, except for the effects of the transfer of entities under common control described in Note 3, as to which the date is August 16, 2007, and except for the change in reportable segments described in Note 23, as to which the date is February 26, 2009

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

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 693	$ 328
Restricted cash and investments	87	104
Short-term investments	25	—
Accounts receivable, net of allowance for doubtful accounts of $22 and $20, respectively	340	426
Accounts receivable, affiliates	1	1
Inventory	184	199
Assets from risk-management activities	1,263	358
Deferred income taxes	6	45
Prepayments and other current assets	204	145
Assets held for sale (Note 4)	—	57
Total Current Assets	2,803	1,663
Property, Plant and Equipment	10,869	10,689
Accumulated depreciation	(1,935)	(1,672)
Property, Plant and Equipment, Net	8,934	9,017
Other Assets		
Unconsolidated investments	15	79
Restricted cash and investments	1,158	1,221
Assets from risk-management activities	114	55
Goodwill	433	438
Intangible assets	437	497
Deferred income taxes	—	6
Accounts receivable, affiliates	4	—
Other long-term assets	315	245
Total Assets	$ 14,213	$ 13,221
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 303	$ 292
Accrued interest	56	56
Accrued liabilities and other current liabilities	160	201
Liabilities from risk-management activities	1,119	397
Notes payable and current portion of long-term debt	64	51
Liabilities held for sale (Note 4)	—	2
Total Current Liabilities	1,702	999
Long-term debt	5,872	5,739

Long-term debt to affiliates	200	200
Long-Term Debt	6,072	5,939
Other Liabilities		
Liabilities from risk-management activities	288	116
Deferred income taxes	1,166	1,250
Other long-term liabilities	500	388
Total Liabilities	9,728	8,692
Commitments and Contingencies (Note 20)		
Stockholders' Equity		
Class A Common Stock, $0.01 par value, 2,100,000,000 shares authorized at December 31, 2008 and December 31, 2007; 505,821,277 shares and 502,819,794 shares issued and outstanding at December 31, 2008 and December 31, 2007, respectively	5	5
Class B Common Stock, $0.01 par value, 850,000,000 shares authorized at December 31, 2008 and December 31, 2007; 340,000,000 shares issued and outstanding at December 31, 2008 and December 31, 2007, respectively	3	3
Additional paid-in capital	6,485	6,463
Subscriptions receivable	(2)	(5)
Accumulated other comprehensive loss, net of tax	(215)	(25)
Accumulated deficit	(1,690)	(1,864)
Treasury stock, at cost, 2,568,286 shares and 2,449,259 shares at December 31, 2008 and December 31, 2007, respectively	(71)	(71)
Total Dynegy Inc. Stockholders' Equity	4,515	4,506
Noncontrolling interests	(30)	23
Total Stockholders' Equity	4,485	4,529
Total Liabilities and Stockholders' Equity	$ 14,213	$ 13,221

See the notes to the consolidated financial statements

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

	Year Ended December 31, 2008	2007	2006
Revenues	$ 3,543	$ 3,092	$ 1,761
Cost of sales	(1,853)	(1,547)	(796)
Operating and maintenance expense, exclusive of depreciation shown separately below	(492)	(460)	(336)
Depreciation and amortization expense	(367)	(320)	(212)
Impairment and other charges	—	—	(119)
Gain on sale of assets, net	82	43	3
General and administrative expenses	(157)	(203)	(196)
Operating income	756	605	105
Losses from unconsolidated investments	(123)	(3)	(1)
Interest expense	(427)	(384)	(382)
Debt conversion costs	—	—	(249)
Other income and expense, net	84	56	54
Income (loss) from continuing operations before income taxes	290	274	(473)
Income tax (expense) benefit	(95)	(151)	152
Income (loss) from continuing operations	195	123	(321)
Income (loss) from discontinued operations, net of tax (expense) benefit of $19, $(91) and $10, respectively (Note 4)	(24)	148	(13)
Income (loss) before cumulative effect of change in accounting principles	171	271	(334)
Cumulative effect of change in accounting principles, net of tax benefit (expense) of zero, zero and zero, respectively (Note 2)	—	—	1
Net income (loss)	171	271	(333)
Less: Net income (loss) attributable to the noncontrolling interests	(3)	7	—
Net income (loss) attributable to Dynegy Inc.	174	264	(333)
Less: Preferred stock dividends (Note 17)	—	—	9
Net income (loss) attributable to Dynegy Inc. common stockholders	$ 174	$ 264	$ (342)
Earnings (Loss) Per Share (Note 19):			
Basic earnings (loss) per share attributable to Dynegy Inc. common stockholders:			
Earnings (loss) from continuing operations	$ 0.24	$ 0.15	$ (0.72)
Income (loss) from discontinued operations	(0.04)	0.20	(0.03)
Cumulative effect of change in accounting principles	—	—	—

Basic earnings (loss) per share attributable to Dynegy Inc. common stockholders	$ 0.20	$ 0.35	$ (0.75)
Diluted earnings (loss) per share attributable to Dynegy Inc. common stockholders:			
Earnings (loss) from continuing operations	$ 0.24	$ 0.15	$ (0.72)
Income (loss) from discontinued operations	(0.04)	0.20	(0.03)
Cumulative effect of change in accounting principles	—	—	—
Diluted earnings (loss) per share attributable to Dynegy Inc. common stockholders	$ 0.20	$ 0.35	$ (0.75)
Basic shares outstanding	840	752	459
Diluted shares outstanding	842	754	509

See the notes to the consolidated financial statements

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

	Year Ended December 31, 2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$171	$271	$(333)
Adjustments to reconcile income (loss) to net cash flows from operating activities:			
Depreciation and amortization	376	333	265
Impairment and other charges	47	—	155
Losses from unconsolidated investments, net of cash distributions	124	3	1
Risk-management activities	(255)	(50)	(87)
Gain on sale of assets, net	(82)	(267)	(5)
Deferred taxes	73	215	(162)
Cumulative effect of change in accounting principles (Note 2)	—	—	(1)
Reserve for doubtful accounts	—	—	(35)
Legal and settlement charges	6	26	(2)
Sithe Subordinated Debt exchange charge (Note 16)	—	—	36
Debt conversion costs	—	—	249
Other	36	35	71
Changes in working capital:			
Accounts receivable	68	(114)	391
Inventory	3	(13)	8
Prepayments and other assets	(51)	(37)	126
Accounts payable and accrued liabilities	(71)	(15)	(885)
Changes in non-current assets	(113)	(57)	11
Changes in non-current liabilities	(13)	11	3
Net cash provided by (used in) operating activities	319	341	(194)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(611)	(379)	(155)
Unconsolidated investments	(6)	3	—
Proceeds from asset sales, net	451	558	227
Business acquisitions, net of cash acquired	—	(128)	(8)
Proceeds from exchange of unconsolidated investments, net of cash acquired (Note 3 and Note 4)	—	—	165
Increase in short-term investments	(27)	—	—
(Increase) decrease in restricted cash	80	(871)	121
Other investing, net	11	—	8
Net cash provided by (used in) investing activities	(102)	(817)	358
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	192	2,758	1,071
Repayments of borrowings	(45)	(2,320)	(1,930)

Debt conversion costs	—	—	(249)
Redemption of Series C Preferred (Note 17)	—	—	(400)
Net proceeds from issuance of capital stock	2	4	183
Dividends and other distributions, net	—	—	(17)
Other financing, net	(1)	(9)	—
Net cash provided by (used in) financing activities	148	433	(1,342)
Net increase (decrease) in cash and cash equivalents	365	(43)	(1,178)
Cash and cash equivalents, beginning of period	328	371	1,549
Cash and cash equivalents, end of period	$693	$328	$371

See the notes to the consolidated financial statements

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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, 2005	$ 3,955	$ 51	$ (8)	$ 4	$ (1,793)	$ (69)	$ 2,140	$ —	$ 2,140
Net loss	—	—	—	—	(333)	—	(333)	—	(333)
Other comprehensive income, net of tax	—	—	—	98	—	—	98	—	98
Adjustment to initially apply SFAS No. 158, net of tax benefit of $21	—	—	—	(35)	—	—	(35)	—	(35)