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

FORM 10-Q

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

For the quarterly period ended June 30, 2010

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

For the transition period from ________ to ________

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

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

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

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

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

Dynegy Inc.	Yes x No ¨
Dynegy Holdings Inc.	Yes x No ¨

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

Dynegy Inc.	Yes x No ¨
Dynegy Holdings Inc.	Yes ¨ No ¨

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

	Large accelerated filer	Accelerated filer	Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company
Dynegy Inc.	x	¨	¨	¨
Dynegy Holdings Inc.	¨	¨	x	¨

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

Dynegy Inc.	Yes ¨ No x
Dynegy Holdings Inc.	Yes ¨ No x

Indicate the number of shares outstanding of Dynegy Inc.'s class of common stock, as of the latest practicable date: Common stock, $0.01 par value per share, 120,599,755 shares outstanding as of August 2, 2010. All of Dynegy Holdings Inc.'s outstanding common stock is owned by Dynegy Inc.

This combined Form 10-Q is separately filed by Dynegy Inc. and Dynegy Holdings Inc. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to a registrant other than itself.

DYNEGY INC. and DYNEGY HOLDINGS INC.

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EXPLANATORY NOTE

This report includes the combined filing of Dynegy Inc. ("Dynegy") and Dynegy Holdings Inc. ("DHI"). DHI is the principal subsidiary of Dynegy, providing nearly 100 percent of Dynegy's total consolidated revenue for the six-month period ended June 30, 2010 and constituting nearly 100 percent of Dynegy's total consolidated asset base as of June 30, 2010. Unless the context indicates otherwise, throughout this report, the terms "the Company," "we," "us," "our" and "our are used to refer to both Dynegy and DHI and their direct and indirect subsidiaries. Discussions or areas of this report that apply only to Dynegy or DHI are clearly noted in such section.

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DEFINITIONS

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

ACES	The American Clean Energy and Security Act of 2009
APB	Accounting Principles Board
BACT	Best available control technology (air)
BART	Best available retrofit technology
BTA	Best technology available
Cal ISO	The California Independent System Operator
CARB	California Air Resources Board
CAA	Clean Air Act
CCA	Coal combustion ash
CCR	Coal combustion residuals
CDWR	California Department of Water Resources
CEC	California Energy Commission
CFTC	Commodity Futures Trading Commission
CO2	Carbon Dioxide
CRM	Our former customer risk management business segment
CUSA	Chevron U.S.A. Inc., a wholly owned subsidiary of Chevron Corporation
DHI	Dynegy Holdings Inc.
DMG	Dynegy Midwest Generation, Inc.
DMSLP	Dynegy Midstream Services L.P.
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles of the United States of America
GEN	Our power generation business
GEN-MW	Our power generation business - Midwest segment
GEN-NE	Our power generation business - Northeast segment
GEN-WE	Our power generation business - West segment
GHG	Greenhouse Gas
ICC	Illinois Commerce Commission
IMA	In-market asset availability
ISO	Independent System Operator
LNG	Liquefied natural gas
MISO	Midwest Independent Transmission Operator, Inc.
MMBtu	One million British thermal units
MW	Megawatts
MWh	Megawatt hour
NPDES	National Pollutant Discharge Elimination System
NRG	NRG Energy, Inc.
NYSDEC	New York State Department of Environmental Conservation
OAL	Office of Administrative Law
OTC	Over-the-counter
PJM	PJM Interconnection, LLC
PPEA	Plum Point Energy Associates, LLC
PSD	Prevention of significant deterioration
PUHCA	Public Utility Holding Company Act of 1935, as amended
RCRA	Resource Conservation and Recovery Act

RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RSG	Revenue Sufficiency Guarantee
SCEA	Sandy Creek Energy Associates, LP
SCH	Sandy Creek Holdings LLC
SEC	U.S. Securities and Exchange Commission
SPDES	State Pollutant Discharge Elimination System
VaR	Value at Risk
VIE	Variable Interest Entity

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PART I. FINANCIAL INFORMATION

Item 1—FINANCIAL STATEMENTS—DYNEGY INC. AND DYNEGY HOLDINGS INC.

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

	June 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	$282	$471
Restricted cash and investments	87	78
Short-term investments	219	9
Accounts receivable, net of allowance for doubtful accounts of $36 and $22, respectively	198	212
Accounts receivable, affiliates	1	2
Inventory	136	141
Assets from risk-management activities	1,203	713
Deferred income taxes	7	6
Broker margin account	116	286
Prepayments and other current assets	110	120
Total Current Assets	2,359	2,038
Property, Plant and Equipment	8,610	9,071
Accumulated depreciation	(2,081)	(1,954)
Property, Plant and Equipment, Net	6,529	7,117
Other Assets		
Restricted cash and investments	859	877
Assets from risk-management activities	300	163
Intangible assets	165	380
Other long-term assets	384	378
Total Assets	$10,596	$10,953
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$138	$181
Accounts payable, affiliates	8	—
Accrued interest	36	36
Accrued liabilities and other current liabilities	102	127
Liabilities from risk-management activities	1,133	696
Notes payable and current portion of long-term debt	146	807
Total Current Liabilities	1,563	1,847
Long-term debt	4,460	4,575
Long-term debt, affiliates	200	200
Long-Term Debt	4,660	4,775
Other Liabilities		
Liabilities from risk-management activities	362	213

Deferred income taxes	759	780
Other long-term liabilities	342	359
Total Liabilities	$7,686	$7,974
Commitments and Contingencies (Note 12)		
Stockholders’ Equity (Note 15)		
Common Stock, $0.01 par value, 420,000,000 shares authorized at June 30, 2010 and December 31, 2009, and 121,115,507 and 120,715,515 shares issued and outstanding at June 30, 2010 and December 31, 2009, respectively	1	1
Additional paid-in capital	6,062	6,061
Subscriptions receivable	(2)	(2)
Accumulated other comprehensive loss, net of tax	(71)	(150)
Accumulated deficit	(3,009)	(2,937)
Treasury stock, at cost, 627,607 and 557,677 shares at June 30, 2010 and December 31, 2009, respectively	(71)	(71)
Total Dynegy Inc. Stockholders’ Equity	2,910	2,902
Noncontrolling interests	—	77
Total Stockholders’ Equity	2,910	2,979
Total Liabilities and Stockholders’ Equity	$10,596	$10,953

See the notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Revenues	$239	$450	$1,097	$1,354
Cost of sales	(231)	(263)	(539)	(641)
Operating and maintenance expense, exclusive of depreciation shown separately below	(118)	(137)	(231)	(252)
Depreciation and amortization expense	(90)	(89)	(165)	(175)
Goodwill impairments	—	—	—	(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	(1)	(387)	(1)	(387)
General and administrative expenses	(28)	(45)	(59)	(83)
Operating income (loss)	(229)	(471)	102	(617)
Earnings (losses) from unconsolidated investments	—	13	(34)	21
Interest expense	(91)	(98)	(180)	(196)
Other income and expense, net	1	4	2	8
Loss from continuing operations before income taxes	(319)	(552)	(110)	(784)
Income tax benefit (Note 14)	128	204	63	113
Loss from continuing operations	(191)	(348)	(47)	(671)
Income (loss) from discontinued operations, net of tax benefit of zero, $1, zero and $7, respectively (Note 2)	—	2	1	(12)
Net loss	(191)	(346)	(46)	(683)
Less: Net loss attributable to the noncontrolling interests	—	(1)	—	(3)
Net loss attributable to Dynegy Inc.	$(191)	$(345)	$(46)	$(680)
Loss Per Share (Notes 11 and 15):				
Basic loss per share attributable to Dynegy Inc. common stockholders:				
Loss from continuing operations	$(1.59)	$(2.06)	$(0.39)	$(3.98)
Income (loss) from discontinued operations	—	0.01	0.01	(0.07)
Basic loss per share attributable to Dynegy Inc. common stockholders	$(1.59)	$(2.05)	$(0.38)	$(4.05)
Diluted loss per share attributable to Dynegy Inc. common stockholders:				
Loss from continuing operations	$(1.59)	$(2.06)	$(0.39)	$(3.98)
Income (loss) from discontinued operations	—	0.01	0.01	(0.07)

Diluted loss per share attributable to Dynegy Inc. common stockholders	$(1.59)	$(2.05)	$(0.38)	$(4.05)
Basic shares outstanding	120	168	120	168
Diluted shares outstanding	121	169	121	169

See the notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(46)	$(683)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation and amortization	172	189
Goodwill impairments	—	433
Impairment and other charges, exclusive of goodwill impairments shown separately above	1	410
(Earnings) losses from unconsolidated investments, net of cash distributions	34	(21)
Risk-management activities	8	(65)
Gain on sale of assets	—	(10)
Deferred income taxes	(62)	(129)
Other	30	43
Changes in working capital:		
Accounts receivable	14	35
Inventory	3	(9)
Broker margin account	255	(80)
Prepayments and other assets	8	(8)
Accounts payable and accrued liabilities	(36)	(13)
Changes in non-current assets	(17)	(38)
Changes in non-current liabilities	4	6
Net cash provided by operating activities	368	60
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(201)	(303)
Unconsolidated investments	(15)	1
Proceeds from asset sales, net	—	105
Maturities of short-term investments	36	14
Purchases of short-term investments	(331)	—
Increase in restricted cash and restricted investments	(10)	(33)
Other investing	—	3
Net cash used in investing activities	(521)	(213)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of financing costs	(5)	54
Repayments of borrowings	(31)	—
Net cash (used in) provided by financing activities	(36)	54
Net decrease in cash and cash equivalents	(189)	(99)

Cash and cash equivalents, beginning of period	471	693
Cash and cash equivalents, end of period	$282	$594
Other non-cash investing activity:		
Non-cash capital expenditures	$6	$42

See the notes to condensed consolidated financial statements.

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Net loss	$(191)	$(346)
Cash flow hedging activities, net:		
Unrealized mark-to-market gains arising during period, net	—	81
Deferred losses on cash flow hedges, net	—	(3)
Changes in cash flow hedging activities, net (net of tax expense of zero and $7, respectively)	—	78
Amortization of unrecognized prior service cost and actuarial gain (net of tax (expense) benefit of $(1) and $2)	—	3
Unconsolidated investments other comprehensive income, net (net of tax expense of zero and $2)	—	5
Other comprehensive income, net of tax	—	86
Comprehensive loss	(191)	(260)
Less: Comprehensive income attributable to the noncontrolling interests	—	56
Comprehensive loss attributable to Dynegy Inc.	$(191)	$(316)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net loss	$(46)	$(683)
Cash flow hedging activities, net:		
Unrealized mark-to-market gains arising during period, net	—	115
Deferred losses on cash flow hedges, net	—	(6)
Changes in cash flow hedging activities, net (net of tax expense of zero and $16, respectively)	—	109
Amortization of unrecognized prior service cost and actuarial gain (net of tax expense of $1 and $1)	2	2
Unconsolidated investments other comprehensive income, net (net of tax expense of zero and $4)	—	6
Other comprehensive income, net of tax	2	117
Comprehensive loss	(44)	(566)
Less: Comprehensive income attributable to the noncontrolling interests	—	82

Comprehensive loss attributable to Dynegy Inc.	$(44)	$(648)

See the notes to condensed consolidated financial statements.

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DYNEGY HOLDINGS INC.
CONDENSED CONSOLIDATED BALANCE SHEET
(unaudited) (in millions)

	June 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	$244	$419
Restricted cash and investments	87	78
Short-term investments	204	8
Accounts receivable, net of allowance for doubtful accounts of $17 and $20, respectively	195	214
Accounts receivable, affiliates	1	2
Inventory	136	141
Assets from risk-management activities	1,203	713
Deferred income taxes	6	7
Broker margin account	116	286
Prepayments and other current assets	110	120
Total Current Assets	2,302	1,988
Property, Plant and Equipment	8,610	9,071
Accumulated depreciation	(2,081)	(1,954)
Property, Plant and Equipment, Net	6,529	7,117
Other Assets		
Restricted cash and investments	859	877
Assets from risk-management activities	300	163
Intangible assets	165	380
Other long-term assets	384	378
Total Assets	$10,539	$10,903
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$138	$181
Accounts payable, affiliates	8	—
Accrued interest	36	36
Accrued liabilities and other current liabilities	102	128
Liabilities from risk-management activities	1,133	696
Notes payable and current portion of long-term debt	146	807
Total Current Liabilities	1,563	1,848
Long-term debt	4,460	4,575
Long-term debt, affiliates	200	200
Long-Term Debt	4,660	4,775
Other Liabilities		
Liabilities from risk-management activities	362	213
Deferred income taxes	685	704
Other long-term liabilities	342	360
Total Liabilities	7,612	7,900
Commitments and Contingencies (Note 12)		
Stockholders' Equity		

Capital Stock, $1 par value, 1,000 shares authorized at June 30, 2010 and December 31, 2009	—	—
Additional paid-in capital	5,135	5,135
Affiliate receivable	(777)	(777)
Accumulated other comprehensive loss, net of tax	(71)	(150)
Accumulated deficit	(1,360)	(1,282)
Total Dynegy Holdings Inc. Stockholder’s Equity	2,927	2,926
Noncontrolling interests	—	77
Total Stockholders’ Equity	2,927	3,003
Total Liabilities and Stockholders’ Equity	$10,539	$10,903

See the notes to condensed consolidated financial statements.

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenues	$ 239	$ 450	$ 1,097	$ 1,354
Cost of sales	(231)	(263)	(539)	(641)
Operating and maintenance expense, exclusive of depreciation shown separately below	(118)	(137)	(231)	(254)
Depreciation and amortization expense	(90)	(89)	(165)	(175)
Goodwill impairments	—	—	—	(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	(1)	(387)	(1)	(387)
General and administrative expenses	(28)	(45)	(59)	(83)
Operating income (loss)	(229)	(471)	102	(619)
Earnings (losses) from unconsolidated investments	—	13	(34)	20
Interest expense	(91)	(98)	(180)	(196)
Other income and expense, net	1	3	2	7
Loss from continuing operations before income taxes	(319)	(553)	(110)	(788)
Income tax benefit (Note 14)	128	205	56	117
Loss from continuing operations	(191)	(348)	(54)	(671)
Income (loss) from discontinued operations, net of tax benefit of zero, $11, zero and $17, respectively (Note 2)	—	12	1	(2)
Net loss	(191)	(336)	(53)	(673)
Less: Net loss attributable to the noncontrolling interests	—	(1)	—	(3)
Net loss attributable to Dynegy Holdings Inc.	$ (191)	$ (335)	$ (53)	$ (670)

See the notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(53)	$(673)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation and amortization	172	189
Goodwill impairments	—	433
Impairment and other charges, exclusive of goodwill impairments shown separately above	1	410
(Earnings) losses from unconsolidated investments, net of cash distributions	34	(20)
Risk-management activities	8	(65)
Gain on sale of assets, net	—	(10)
Deferred income taxes	(55)	(139)
Other	27	43
Changes in working capital:		
Accounts receivable	19	35
Inventory	3	(9)
Broker margin account	255	(80)
Prepayments and other assets	8	(8)
Accounts payable and accrued liabilities	(37)	5
Changes in non-current assets	(17)	(38)
Changes in non-current liabilities	4	7
Net cash provided by operating activities	369	80
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(201)	(303)
Unconsolidated investments	(15)	—
Proceeds from asset sales, net	—	105
Maturities of short-term investments	36	13
Purchases of short-term investments	(316)	—
Increase in restricted cash and restricted investments	(10)	(33)
Affiliate transactions	(2)	(3)
Other investing	—	3
Net cash used in investing activities	(508)	(218)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of financing costs	(5)	54
Repayments of borrowings	(31)	—
Dividend to affiliate	—	(175)
Net cash used in financing activities	(36)	(121)

Net decrease in cash and cash equivalents	(175)	(259)
Cash and cash equivalents, beginning of period	419	670
Cash and cash equivalents, end of period	$244	$411
Other non-cash investing activity:		
Non-cash capital expenditures	$6	$42

See the notes to condensed consolidated financial statements.

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Net loss	$(191)	$(336)
Cash flow hedging activities, net:		
Unrealized mark-to-market gains arising during period, net	—	81
Deferred losses on cash flow hedges, net	—	(3)
Changes in cash flow hedging activities, net (net of tax expense of zero and $7, respectively)	—	78
Amortization of unrecognized prior service cost and actuarial gain (net of tax (expense) benefit of $(1) and $2)	—	3
Unconsolidated investments other comprehensive income, net (net of tax expense of zero and $2)	—	5
Other comprehensive income, net of tax	—	86
Comprehensive loss	(191)	(250)
Less: Comprehensive income attributable to the noncontrolling interests	—	56
Comprehensive loss attributable to Dynegy Holdings Inc.	$(191)	$(306)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net loss	$(53)	$(673)
Cash flow hedging activities, net:		
Unrealized mark-to-market gains arising during period, net	—	115
Deferred losses on cash flow hedges, net	—	(6)
Changes in cash flow hedging activities, net (net of tax expense of zero and $16, respectively)	—	109
Amortization of unrecognized prior service cost and actuarial gain (net of tax expense of $1 and $1)	2	2
Unconsolidated investments other comprehensive income, net (net of tax expense of zero and $4)	—	6
Other comprehensive income, net of tax	2	117
Comprehensive loss	(51)	(556)
Less: Comprehensive income attributable to the noncontrolling interests	—	82

Comprehensive loss attributable to Dynegy Holdings Inc.	$(51)	$(638)

See the notes to condensed consolidated financial statements.

DYNEGY INC. and DYNEGY HOLDINGS INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2010 and 2009

Note 1—Accounting Policies

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with the instructions to interim financial reporting as prescribed by the SEC. These interim financial statements do not include all disclosures required by accounting principles generally accepted in the United States of America. These interim financial statements should be read together with the consolidated financial statements and notes thereto included in Dynegy's and DHI's Form 10-K for the year ended December 31, 2009 filed on February 25, 2010, which we refer to as each registrant's "Form 10-K".

The December 31, 2009 condensed consolidated balance sheet data was derived from audited consolidated financial statements, as adjusted for the 1-for-5 reverse stock split of Dynegy's common stock that became effective on May 25, 2010. Please read Note 15—Capital Stock for further discussion.

The unaudited condensed consolidated financial statements contained in this report include all material adjustments of a normal and recurring nature that, in the opinion of management, are necessary for a fair statement of the results for the interim periods. The results of operations for the interim periods presented in this Form 10-Q are not necessarily indicative of the results to be expected for the full year or any other interim period due to seasonal fluctuations in demand for our energy products and services, changes in commodity prices, timing of maintenance and other expenditures and other factors. The preparation of the unaudited condensed consolidated financial statements in conformity with GAAP requires management to make informed estimates and judgments that affect our reported financial position and results of operations. These estimates and judgments also impact the nature and extent of disclosure, if any, of our contingent liabilities based on currently available information. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (i) developing fair value assumptions, including estimates of future cash flows and discount rates, (ii) analyzing tangible and intangible assets for possible impairment, (iii) estimating the useful lives of our assets, (iv) assessing future tax exposure and the realization of tax assets, (v) determining amounts to accrue for contingencies, guarantees and indemnifications, (vi) estimating various factors used to value our pension assets and liabilities and (vii) determining the primary beneficiary of certain VIEs from a set of related parties. Actual results could differ materially from any such estimates. Certain reclassifications have been made to prior period amounts in order to conform to current year presentation.

Short-Term Investments. Short-term investments consist of highly liquid investments, primarily U.S. Treasury, U.S. Agency and corporate debt securities, with original maturities over three months from the date of purchase. Our investment policy restricts investments to high credit quality investments with limits on the length to maturity and the amount invested with any one issuer. Debt securities which we have the ability and positive intent to hold to maturity are carried at amortized cost, net of unamortized premiums and unaccreted discounts, which approximates fair value. At June 30, 2010, we did not hold any short-term investments that were classified as held-to-maturity.

Debt securities not held-to-maturity are classified as available for sale and are recorded at fair value. Unrealized gains and losses, after applicable taxes, resulting from changes in fair value are recorded as a component of Other comprehensive income (loss).

Declines in the value of individual equity securities that are considered other than temporary result in write-downs to the individual securities to their fair value and the write-downs are included in the condensed consolidated statements of operations. Declines in debt securities held-to-maturity and available for sale, that are considered other than temporary, result in write-downs when it is more likely than not that we will sell the securities before we recover our cost. If we do not intend to sell an impaired debt security but do not expect to recover its cost, we determine whether a credit loss exists, and if so, the credit loss is recognized in the condensed consolidated statements of operations and any remaining impairment is recognized in Other comprehensive income (loss). The review for other-than-temporary declines considers the length of time and the extent to which the fair value has been less than cost, the financial condition and near-term prospects of the issuer, and our intent and ability to retain the investment for a period of time sufficient to allow for recovery.

We consider all available for sale securities, including those with maturity dates beyond twelve months, as available to support current operational liquidity needs and therefore classify these securities as short-term investments within current assets on the consolidated balance sheets. As of June 30, 2010, Dynegy and DHI held $305 million and $290 million, respectively, of available for sale securities with maturity dates within one year. Of these amounts, $86 million is included in the Broker margin account on our unaudited condensed consolidated balance sheets.

Interest on securities, including the amortization of premiums and the accretion of discounts, is reported in Other income and expense, net using the interest method over the lives of the securities, adjusted for actual prepayments. Gains and losses on the sale of securities are recorded on the trade date and recognized using the specific identification method and reported in Other income and expense, net.

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Accounting Principle Adopted

Variable Interest Entities. On January 1, 2010, we adopted Accounting Standards Update ("ASU") No. 2009-17—Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities ("ASU No. 2009-17"). This guidance replaces the previous quantitative-based analysis for determining the primary beneficiary of a variable interest entity with a framework that is based on qualitative judgments. The new guidance identifies the primary beneficiary of a variable interest entity as the party that both: (i) has the power to direct the activities of a variable interest entity that most significantly impact its economic performance and (ii) has an obligation to absorb losses or a right to receive benefits that could potentially be significant to the variable interest entity. As a result of applying this guidance, we have determined that we are not the primary beneficiary of PPEA Holding Company, LLC ("PPEA Holding") because we lack the power to direct the activities that most significantly impact PPEA Holding's economic performance. The activities that most significantly impact PPEA Holding's economic performance are changes to the costs to complete the facility, modifications to the off-take agreements, and/or changes in the financing structure. As PPEA Holding's LLC Agreement currently requires that those activities be approved by all members, the power to direct these activities is shared with the other owners of PPEA Holding and the participants in the 665 MW coal-fired power generation facility (the "Plum Point Project"). We have historically consolidated PPEA Holding in our consolidated financial statements.

The adoption of ASU No. 2009-17 resulted in a deconsolidation of our investment in PPEA Holding, which resulted in the cumulative effect of a change in accounting principle of approximately $41 million ($25 million after tax), which was recorded as an increase in Accumulated deficit on our unaudited condensed consolidated balance sheets as of January 1, 2010. This pre-tax charge reflects the difference in the assets, liabilities and equity (including Other comprehensive loss) that we have historically included in our consolidated balance sheets and the carrying value of the equity investment and related accumulated other comprehensive loss that we would have recorded had we accounted for our investment in PPEA Holding as an equity method investment since April 2, 2007, the date we acquired an interest in PPEA Holding. On January 1, 2010, we recorded an equity investment of approximately $19 million and accumulated other comprehensive loss of approximately $29 million ($17 million after tax). The $19 million equity investment balance at January 1, 2010 reflects the fair value of our investment at that date, after an other than temporary pre-tax impairment charge of approximately $32 million that would have been recorded in 2009 had we accounted for our investment in PPEA Holding as an equity investment at that time. Our assessment of the fair value of our investment in PPEA Holding at January 1, 2010 reflects the risk associated with PPEA Holding's financing arrangement at that date. Please read Note 6— Fair Value Measurements for further discussion about the assumptions used to determine the fair value of our investment as of January 1, 2010. Please read Note 17—Debt—Plum Point (including PPEA Credit Agreement Facility and PPEA Tax Exempt Bonds) and Note 14—Variable Interest Entities—PPEA Holding Company, LLC in our Form 10-K for further discussion. Summarized aggregate financial information for PPEA Holding, included in our December 31, 2009 consolidated balance sheets, is included below (in millions):

Current assets	$6
Property, plant and equipment, net	611
Intangible asset	190
Other non-current asset	20
Total assets	827
Current portion of long-term debt	744
Current liabilities	74

Noncontrolling interest	77
Accumulated other comprehensive loss	(157)

The adoption of ASU No. 2009-17 had no impact on our investment in the Hydroelectric Generation Facilities. Please read Note 8—Variable Interest Entities—Hydroelectric Generation Facilities for further discussion.

Disclosures about Fair Value Measurements. On January 1, 2010, we adopted ASU No. 2010-06—Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. Please read Note 6—Fair Value Measurements for further discussion.

Note 2—Dispositions and Discontinued Operations

Dispositions

LS Power Transactions. We consummated our transactions (the "LS Power Transactions") with LS Power Partners, L.P. and certain of its affiliates ("LS Power") in two parts, with the issuance of $235 million of notes by DHI on December 1, 2009, and the remainder of the transactions closing on November 30, 2009. Please read Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations in our Form 10-K for further discussion of these transactions.

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Discontinued Operations

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

The Arizona power generation facilities, as well as our Bluegrass facility, met the criteria of held for sale during the third quarter 2009. At that time, we discontinued depreciation and amortization of the Arizona power generation facilities' and Bluegrass' property, plant and equipment. Depreciation and amortization expense related to the Arizona power generation facilities totaled approximately $5 million and $10 million in the three- and six-month periods ended June 30, 2009. Depreciation and amortization expense related to Bluegrass totaled approximately zero and $1 million in the three- and six-month periods ended June 30, 2009, respectively. We recorded a pre-tax impairment of approximately $5 million in the period ended March 31, 2009 and approximately $18 million in the period ended June 30, 2009 related to the Bluegrass facility. We are reporting the results of operations for the Arizona power generation facilities and the Bluegrass power generation facility in discontinued operations for all periods presented.

Heard County. On April 30, 2009, we completed our sale of our interest in the Heard County power generation facility for approximately $105 million.

Heard County was classified as held for sale during the first quarter 2009. At that time, we discontinued depreciation and amortization of Heard County's property, plant and equipment. Depreciation and amortization expense related to Heard County totaled zero and $1 million in the three- and six-month periods ended June 30, 2009, respectively. We are reporting the results of Heard County's operations in discontinued operations for all periods presented.

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

	GEN-MW	GEN-WE (in millions)	Total
Three Months Ended June 30, 2009			
Revenues	$2	$41	$43
Income (loss) from operations before taxes (1)	(17)	8	(9)
Income (loss) from operations after taxes	(10)	6	(4)
Gain on sale before taxes	—	10	10
Gain on sale after taxes	—	6	6
Six Months Ended June 30, 2010			
Revenues	$—	$—	$—
Income from operations before taxes	—	1	1
Income from operations after taxes	—	1	1
Six Months Ended June 30, 2009			
Revenues	$3	$42	$45
	(23)	(6)	(29)

Loss from operations before taxes (2)			
Loss from operations after taxes	(14)	(4)	(18)
Gain on sale before taxes	—	10	10
Gain on sale after taxes	—	6	6

(1) Includes $18 million of impairment charges related to our Bluegrass power generation facility in the GEN-MW segment.
(2) Includes $23 million of impairment charges related to our Bluegrass power generation facility in the GEN-MW segment.

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

	GEN-MW	GEN-WE (in millions)	Total
Three Months Ended June 30, 2009			
Revenues	$2	$41	$43
Income (loss) from operations before taxes (1)	(17)	8	(9)
Income (loss) from operations after taxes	(10)	10	—
Gain on sale before taxes	—	10	10
Gain on sale after taxes	—	12	12
Six Months Ended June 30, 2010			
Revenues	$—	$—	$—
Income from operations before taxes	—	1	1
Income from operations after taxes	—	1	1
Six Months Ended June 30, 2009			
Revenues	$3	$42	$45
Loss from operations before taxes (2)	(23)	(6)	(29)
Loss from operations after taxes	(14)	—	(14)
Gain on sale before taxes	—	10	10
Gain on sale after taxes	—	12	12

(1) Includes $18 million of impairment charges related to our Bluegrass power generation facility in the GEN-MW segment.
(2) Includes $23 million of impairment charges related to our Bluegrass power generation facility in the GEN-MW segment.

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Note 3—Noncontrolling Interests

On January 1, 2009, we adopted authoritative guidance which requires: (i) ownership interests in subsidiaries held by parties other than the parent to be clearly identified, labeled, and presented in the consolidated statements of financial position within equity, but separate from the parent's equity; (ii) the amount of consolidated net income (loss) attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statements of operations; (iii) changes in a parent's ownership interests that do not result in deconsolidation to be accounted for as equity transactions; and (iv) that a parent recognize a gain or loss in net income upon deconsolidation of a subsidiary, with any retained noncontrolling equity investment in the former subsidiary initially measured at fair value. The following table presents the net loss attributable to Dynegy's and DHI's stockholders:

	Three Months Ended June 30, 2009	
	Dynegy Inc.	Dynegy Holdings Inc.
	(in millions)	
Loss from continuing operations	$ (347)	$ (347)
Income from discontinued operations, net of tax benefit of $1 and $11, respectively	2	12
Net loss	$ (345)	$ (335)

	Six Months Ended June 30, 2009	
	Dynegy Inc.	Dynegy Holdings Inc.
	(in millions)	
Loss from continuing operations	$ (668)	$ (668)
Loss from discontinued operations, net of tax benefit of $7 and $17, respectively	(12)	(2)
Net loss	$ (680)	$ (670)

As a result of the deconsolidation of PPEA Holding, effective January 1, 2010, there are no longer any noncontrolling interests in any of our consolidated subsidiaries, and as such, no reconciliation is needed for the six months ended June 30, 2010. The following table presents a reconciliation of the carrying amount of total equity, equity attributable to Dynegy and the equity attributable to the noncontrolling interests at the beginning and the end of the six months ended June 30, 2009.

Total

	Controlling Interest	Noncontrolling Interests (in millions)	
December 31, 2008	$ 4,515	$ (30)	$ 4,485
Net loss	(680)	(3)	(683)
Other comprehensive income (loss), net of tax:			
Unrealized mark-to-market gains arising during period	25	90	115
Reclassification of mark-to-market (gains) losses to earnings	(2)	2	—
Deferred gains (losses) on cash flow hedges	1	(7)	(6)
Amortization of unrecognized prior service cost and actuarial gain	2	—	2
Unconsolidated investments other comprehensive income	6	—	6
Total other comprehensive income, net of tax	32	85	117
Other equity activity:			
Options exercised	(1)	—	(1)
Options and restricted stock granted	5	—	5
401(k) plan and profit sharing stock	3	—	3
Board of directors stock compensation	(2)	—	(2)
June 30, 2009	$ 3,872	$ 52	$ 3,924

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As a result of the deconsolidation of PPEA Holding, effective January 1, 2010, there are no longer any noncontrolling interests in any of our consolidated subsidiaries, and as such, no reconciliation is needed for the six months ended June 30, 2010. The following table presents a reconciliation of the carrying amount of total equity, equity attributable to DHI and the equity attributable to the noncontrolling interests at the beginning and the end of the six months ended June 30, 2009.

	Controlling Interest	Noncontrolling Interests (in millions)	Total
December 31, 2008	$ 4,613	$ (30)	$ 4,583
Net loss	(670)	(3)	(673)
Other comprehensive income (loss), net of tax:			
Unrealized mark-to-market gains arising during period	25	90	115
Reclassification of mark-to-market (gains) losses to earnings	(2)	2	—
Deferred gains (losses) on cash flow hedges	1	(7)	(6)
Amortization of unrecognized prior service cost and actuarial gain	2	—	2
Unconsolidated investments other comprehensive income	6	—	6
Total other comprehensive income, net of tax	32	85	117
Other equity activity:			
Dividend to Dynegy	(175)	—	(175)
Contribution from Dynegy	36	—	36
June 30, 2009	$ 3,836	$ 52	$ 3,888

Note 4—Investments

The amortized cost basis, unrealized gains and losses and fair values of investments in available for sale investments as of June 30, 2010, is shown in the table below:

	Cost Basis	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(in millions)		
Available for Sale investments:				
Commercial Paper	$21	$—	$—	$21
Certificates of Deposit	36	—	—	36
Corporate Securities	22	—	—	22
Non U.S. Government Securities	1	—	—	1
U.S. Treasury and Government Securities (1)	210	—	—	210

Total—DHI	$290	$—	$—	$290
Certificates of Deposit	3	—	—	3
Corporate Securities	3	—	—	3
U.S. Treasury and Government Securities	9	—	—	9
Total—Dynegy	$305	$—	$—	$305

(1) Includes $86 million in Broker margin account on our consolidated balance sheets in support of transactions with our futures clearing manager.

During the three and six months ended June 30, 2010, we received proceeds of $46 million from the sale of available for sale securities. We realized an immaterial amount of gains and losses on the sale of these available for sale securities in earnings for the three and six months ended June 30, 2010.

Note 5—Risk Management Activities, Derivatives and Financial Instruments

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

Our commodity risk management strategy gives us the flexibility to sell energy and capacity through a combination of spot market sales and near-term contractual arrangements (generally over a rolling 1 to 3 year time frame). Our commodity risk management goal is to increase predictability of cash flows in the near-term while keeping the ability to capture value from rising commodity prices that are anticipated over the longer term. Many of our contractual arrangements are derivative instruments and must be accounted for at fair value. We also manage commodity price risk by entering into capacity forward sales arrangements, tolling arrangements, RMR contracts, fixed price coal purchases and other arrangements that do not receive fair value accounting treatment because these arrangements do not meet the definition of a derivative or are designated as “normal purchase normal sales.” As a result, the gains and losses with respect to these arrangements are not reflected in the unaudited condensed consolidated statements of operations until the settlement dates.

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Quantitative Disclosures Related to Financial Instruments and Derivatives

The following disclosures and tables present information concerning the impact of derivative instruments on our unaudited condensed consolidated balance sheets and statements of operations. In the table below, commodity contracts primarily consist of derivative contracts related to our power generation business that we have not designated as accounting hedges, that are entered into for purposes of hedging future fuel requirements and sales commitments and securing commodity prices. Interest rate contracts primarily consist of derivative contracts related to managing our interest rate risk. As of June 30, 2010, our commodity derivatives were comprised of both long and short positions; a long position is a contract to purchase a commodity, while a short position is a contract to sell a commodity. As of June 30, 2010, we had net long/ (short) commodity derivative contracts outstanding and notional interest rate swaps outstanding in the following quantities:

Contract Type	Hedge Designation	Quantity (in millions)	Unit of Measure	Net Fair Value (in millions)
Commodity contracts:				
Electric energy (1)	Not designated	(93)	MW	$ 261
Natural gas (1)	Not designated	205	MMBtu	$ (235)
Heat rate derivatives	Not designated	(9)/77	MW/MMBtu	$ (23)
Other (2)	Not designated	2	Misc.	$ 5
Interest rate contracts:				
Interest rate swaps	Fair value hedge	(25)	Dollars	$ 1
Interest rate swaps	Not designated	231	Dollars	$ (10)
Interest rate swaps	Not designated	(206)	Dollars	$ 9

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

Derivatives on the Balance Sheet. We execute a significant volume of transactions through a futures clearing manager. Our daily cash payments (receipts) to (from) our futures clearing manager consist of three parts: (i) fair value of open positions (exclusive of options) (“Daily Cash Settlements”); (ii) initial margin requirements related to open positions (exclusive of options) (“Initial Margin”); and (iii) fair value and margin requirements related to options (“Options”, and collectively with Initial Margin, “Collateral”). We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement and we do not elect to offset the fair value amounts recognized for the Daily Cash Settlements paid or received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement.

As a result, our consolidated balance sheets present derivative assets and liabilities, as well as related Daily Cash Settlements and Collateral, as applicable, on a gross basis. As of June 30, 2010, the net value of our Daily Cash Settlements and Collateral with our futures clearing manager totaled $160 million. The $160 million is comprised of approximately $156 million of Collateral and approximately $4 million of Daily Cash Settlements due from the broker. Approximately $113 million of the $160 million is included in Broker margin account on our unaudited condensed consolidated balance sheets. The remaining $47 million represents collateral requirements secured by letters of credit. As of June 30, 2010, the Broker margin account includes $86 million of short-term investments posted as collateral. In the second quarter 2010, we began using short-term investments to collateralize a portion of our collateral requirements. The broker requires that we post approximately 103 percent of any collateral requirement collateralized with short-term investments. Accordingly, our Broker margin account includes approximately $3 million related to this requirement. As of December 31, 2009, of the approximately $286 million included in Broker margin account on our consolidated balance sheets, approximately $288 million represented Collateral, offset by approximately $2 million representing Daily Cash Settlements.

The following table presents the fair value and balance sheet classification of derivatives in the unaudited condensed consolidated balance sheet as of June 30, 2010, and December 31, 2009 segregated between designated, qualifying hedging instruments and those that are not, and by type of contract segregated by assets and liabilities.

Contract Type	Balance Sheet Location	June 30, 2010	December 31, 2009
		(in millions)	
Derivatives designated as hedging instruments:			
Derivative Assets:			
Interest rate contracts	Assets from risk management activities	$ 1	$ 2
Derivative Liabilities:			
Interest rate contracts	Liabilities from risk management activities	—	—
Total derivatives designated as hedging instruments		1	2
Derivatives not designated as hedging instruments:			
Derivative Assets:			
Commodity contracts	Assets from risk management activities	1,493	861
Interest rate contracts	Assets from risk management activities	9	13
Derivative Liabilities:			
Commodity contracts	Liabilities from risk management activities	(1,485)	(844)
Interest rate contracts	Liabilities from risk management activities	(10)	(65)
Total derivatives not designated as hedging instruments		7	(35)
Total derivatives, net		$ 8	$ (33)

Impact of Derivatives on the Consolidated Statements of Operations

The following discussion and tables present the disclosure of the location and amount of gains and losses on derivative instruments in our unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2010 and 2009 segregated between designated, qualifying hedging instruments and those that are not, by type of contract.

Cash Flow Hedges. We enter into financial derivative instruments that qualify, and that we may elect to designate, as cash flow hedges. Interest rate swaps have been used to convert floating interest rate obligations to fixed interest rate obligations.

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In 2007, a formerly consolidated variable interest entity, PPEA, entered into three interest rate swap agreements which were designated as cash flow hedges. PPEA Holding was deconsolidated on January 1, 2010 upon adoption of ASU No. 2009-17, and therefore these instruments are not reflected in our consolidated risk management accounts at June 30, 2010. Please read Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities for further discussion.

During the three and six months ended June 30, 2010 and 2009, we recorded no income or loss, related to ineffectiveness from changes in fair value of derivative positions and no amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows in either of the periods. During the three and six months ended June 30, 2010 and 2009, no amounts were reclassified to earnings in connection with forecasted transactions that were considered probable of not occurring.

The balance in cash flow hedging activities within Accumulated other comprehensive loss, net at June 30, 2010, representing our share of the historical cash flow hedging activities of PPEA under the equity method, is expected to be reclassified to future earnings when the forecasted hedged transaction impacts earnings. Currently we do not expect to make any reclassifications into earnings over the 12-month period ending June 30, 2011, unless we complete a sale of our investment in PPEA Holding during such period. The actual amounts that will be reclassified to earnings over this period and beyond could vary materially from this estimated amount as a result of changes in market prices, hedging strategies, the probability of forecasted transactions occurring and other factors.

The amount of gain recognized in Other comprehensive loss on the effective portion of interest rate derivatives for the three and six months ended June 30, 2009 was $80 million and $115 million, respectively. As of July 28, 2009, these derivatives no longer qualified for cash flow hedge accounting, and therefore, no additional gains or losses have been recognized in Other comprehensive loss since that date. During the three months ended June 30, 2010 and 2009, zero and $1 million, respectively, of losses were reclassified from Accumulated other comprehensive loss into earnings. During the six months ended June 30, 2010 and 2009, zero and $2 million, respectively, of losses were reclassified from Accumulated other comprehensive loss into earnings.

Fair Value Hedges. We also enter into derivative instruments that qualify, and that we may elect to designate, as fair value hedges. We use interest rate swaps to convert a portion of our non-prepayable fixed-rate debt into floating-rate debt. The maximum length of time for which we have hedged our exposure for fair value hedges is through 2011. During the three and six months ended June 30, 2010 and 2009, there was no ineffectiveness from changes in the fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. During three and six months ended June 30, 2010 and 2009, there were no gains or losses related to the recognition of firm commitments that no longer qualified as fair value hedges.

The impact of interest rate swap contracts designated as fair value hedges and the related hedged item on our unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2010 and 2009 was immaterial.

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

For the three months ended June 30, 2010, our revenues included approximately $258 million of mark-to-market losses related to this activity compared to $111 million of mark-to-market losses in the same period in the prior year. For the six months ended June 30, 2010, our revenues included approximately $5 million of mark-to-market losses related to this activity compared to $58 million of mark-to-market gains in the same period in the prior year.

The impact of derivative financial instruments that have not been designated as hedges on our unaudited condensed consolidated statement of operations for the three months ended June 30, 2010 and 2009 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we expect to realize when the underlying physical transactions settle.

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives for the Three Months Ended June 30, 2010	2009
		(in millions)	
Commodity contracts	Revenues	$ (185)	$ 20
Interest rate contracts	Interest expense	—	—

The impact of derivative financial instruments that have not been designated as hedges on our unaudited condensed consolidated statement of operations for the six months ended June 30, 2010 and 2009 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we expect to realize when the underlying physical transactions settle.

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives for the Six Months Ended June 30, 2010	2009
		(in millions)	
Commodity contracts	Revenues	$ 140	$ 286
Interest rate contracts	Interest expense	—	—

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Note 6—Fair Value Measurements

Financial Assets and Liabilities. The following tables set forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010 and December 31, 2009. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value as of June 30, 2010			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$711	$66	$777
Natural gas derivatives	—	680	5	685
Heat rate derivatives	—	—	7	7
Other derivatives	—	24	—	24
Total assets from commodity risk management activities	$—	$1,415	$78	$1,493
Assets from interest rate swaps	—	10	—	10
Short-term investments:				
Commercial paper	—	21	—	21
Certificates of deposit	—	36	—	36
Corporate securities	—	22	—	22
Non U.S. government securities	—	1	—	1
U.S. Treasury and government securities (1)	—	210	—	210
Total—DHI short-term investments	$—	$290	$—	$290
Total—DHI	—	1,715	78	1,793
Short-term investments:				
Certificates of deposit	—	3	—	3
Corporate securities	—	3	—	3
U.S. Treasury and government securities	—	9	—	9
Total—Dynegy	$—	$1,730	$78	$1,808
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(473)	$(43)	$(516)
Natural gas derivatives	—	(920)	—	(920)
Heat rate derivatives	—	—	(30)	(30)
Other derivatives	—	(19)	—	(19)
Total liabilities from commodity risk management activities	$—	$(1,412)	$(73)	$(1,485)
Liabilities from interest rate swaps	—	(10)	—	(10)

Total	$—	$(1,422)	$(73)	$(1,495)

(1) Includes $86 million in Broker margin account on our consolidated balance sheets in support of transactions with our futures clearing manager.

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	Fair Value as of December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$ —	$ 442	$ 57	$ 499
Natural gas derivatives	—	302	5	307
Heat rate derivatives	—	—	19	19
Other derivatives	—	36	—	36
Total assets from commodity risk management activities	—	780	81	861
Assets from interest rate swaps	—	15	—	15
Other—DHI (1)	—	8	—	8
Total—DHI	—	803	81	884
Other—Dynegy (1)	—	1	—	1
Total—Dynegy	$ —	$ 804	$ 81	$ 885
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$ —	$ (361)	$ (51)	$ (412)
Natural gas derivatives	—	(401)	—	(401)
Heat rate derivatives	—	—	(2)	(2)
Other derivatives	—	(29)	—	(29)
Total liabilities from commodity risk management activities	—	(791)	(53)	(844)
Liabilities from interest rate swaps	—	(15)	(50)	(65)
Total	$ —	$ (806)	$ (103)	$ (909)

(1) Other represents short-term investments and long-term investments.

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. For example, 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. We have consistently used this valuation technique for all periods presented. Please read Note 2—Summary of Significant Accounting Policies—Fair Value Measurements in our Form 10-K for further discussion.

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

	Three Months Ended June 30, 2010				
	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Interest Rate Swaps	Total
			(in millions)		
Balance at March 31, 2010	$ 70	$ 5	$ 20	$ —	$ 95
Realized and unrealized gains (losses), net	(38)	—	(27)	—	(65)
Purchases, issuances and settlements, net	(9)	—	(16)	—	(25)
Balance at June 30, 2010	$ 23	$ 5	$ (23)	$ —	$ 5
Unrealized losses relating to instruments still held as of June 30, 2010	$ (31)	$ —	$ (27)	$ —	$ (58)

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	Six Months Ended June 30, 2010				
	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Interest Rate Swaps	Total
			(in millions)		
Balance at December 31, 2009	$ 6	$ 5	$ 17	$ (50)	$ (22)
Deconsolidation of Plum Point	—	—	—	50	50
Realized and unrealized gains (losses), net	31	—	(9)	—	22
Purchases, issuances and settlements, net	(14)	—	(31)	—	(45)
Balance at June 30, 2010	$ 23	$ 5	$ (23)	$ —	$ 5
Unrealized gains (losses) relating to instruments still held as of June 30, 2010	$ 21	$ —	$ (17)	$ —	$ 4

	Three Months Ended June 30, 2009				
	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Interest Rate Swaps	Total
			(in millions)		
Balance at March 31, 2009	$ 1	$ 6	$ 26	$ —	$ 33
Realized and unrealized gains (losses), net	5	(1)	24	—	28
Purchases, issuances and settlements, net	(3)	—	(15)	—	(18)
Balance at June 30, 2009	$ 3	$ 5	$ 35	$ —	$ 43
Unrealized gains (losses) relating to instruments still held as of June 30, 2009	$ 4	$ (1)	$ 21	$ —	$ 24

	Six Months Ended June 30, 2009				
	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Interest Rate Swaps	Total
			(in millions)		
Balance at December 31, 2008	$ 7	$ 7	$ 46	$ —	$ 60
Realized and unrealized gains (losses), net	5	(2)	20	—	23

Purchases, issuances and settlements, net	(9)	—	(31)	—	(40)
Balance at June 30, 2009	$ 3	$ 5	$ 35	$ —	$ 43
Unrealized gains (losses) relating to instruments still held as of June 30, 2009	$ (1)	$ (2)	$ 21	$ —	$ 18

Gains and losses (realized and unrealized) for Level 3 recurring items are included in Revenues on the unaudited condensed consolidated statements of operations. We believe an analysis of instruments classified as Level 3 should be undertaken with the understanding that these items generally serve as economic hedges of our power generation portfolio. We did not have any transfers between Level 1, Level 2 and Level 3 for the three and six months ended June 30, 2010 and 2009.

Nonfinancial Assets and Liabilities. The following table sets forth by level within the fair value hierarchy our fair value measurements with respect to nonfinancial assets and liabilities that are measured at fair value on a nonrecurring basis as of June 30, 2009. These assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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Fair Value Measurements as of June 30, 2009

	Level 1	Level 2	Level 3 (in millions)	Total	Total Losses
Assets/Liabilities:					
Goodwill	$ —	$ —	$ —	$ —	$ (433)
Assets held and used	—	—	228	228	(410)
Total	$ —	$ —	$ 228	$ 228	$ (843)

During the first quarter 2009, goodwill with a carrying amount of $433 million was written down to its implied fair value of zero. In order to determine the fair value of our reporting units for purposes of calculating the implied fair value of goodwill, we placed equal weight on a market-based approach and an income approach valuation. Our market-based approach compared our forecasted earnings and Dynegy's market capitalization to those of similarly situated public companies by considering multiples of earnings. Our income approach was based on a discounted cash flows model. This approach used forward-looking projections of our estimated future operating results based on discrete financial forecasts developed by management for planning purposes. Cash flows beyond the discrete forecasts were estimated using a terminal value calculation, which incorporated historical and forecasted financial trends and considered long-term earnings growth rates based on growth rates observed in the power sector. As a result of this analysis, we recorded an impairment charge of $433 million, which is included in Goodwill impairments on our unaudited condensed consolidated statements of operations.

During the six months ended June 30, 2009, long-lived assets held and used with a carrying amount of $638 million were written down to their fair value of $228 million, resulting in an impairment charge of $410 million. Of this amount, $387 million is included in Impairment and other charges on our unaudited condensed consolidated statements of operations. The remaining $23 million related to the Bluegrass power generation facility and related assets and is included in Income (loss) from discontinued operations in our unaudited condensed consolidated statement of operations.

As discussed in Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities, on January 1, 2010, we recorded an impairment of our investment in PPEA Holding as part of our cumulative effect of a change in accounting principle. We determined the fair value of our investment using assumptions that reflect our best estimate of third party market participants' considerations based on the facts and circumstances related to our investment at that time. The fair value of our investment on January 1, 2010 is considered a Level 3 measurement as the fair value was determined based on probability weighted cash flows resulting from various alternative scenarios including no change in the financing structure, a restructuring of the project debt and insolvency. These scenarios and the related probability weighting are consistent with the scenarios used at December 31, 2009 in our long-lived asset impairment analysis. Please read Note 6—Impairment Charges—2009—Impairment Charges—Other in our Form 10-K. At March 31, 2010, we fully impaired our investment in PPEA Holding due to the uncertainty and risk surrounding PPEA's financing structure. During the second quarter 2010, we did not recognize our share of losses from our investment in PPEA Holding. Please read Note 8—Variable Interest Entities—PPEA Holding Company, LLC for further discussion.

Fair Value of Financial Instruments. We have determined the estimated fair-value amounts using available market information and selected valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies could have a material effect on the estimated fair-value amounts.

The carrying values of financial assets and liabilities, not presented in the table below, approximate fair values due to the short-term maturities of these instruments. The fair value of debt as reflected in the table has been calculated based on the average of certain available broker quotes for the periods ending June 30, 2010 and December 31, 2009, respectively.

	June 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Interest rate derivatives designated as fair value accounting hedges (1)	$1	$1	$2	$2
Interest rate derivatives not designated as accounting hedges (1)	(1)	(1)	(52)	(52)
Commodity-based derivative contracts not designated as accounting hedges (1)	8	8	17	17
Term Loan B, due 2013	68	64	68	66
Term Facility, floating rate due 2013	850	798	850	814
Senior Notes and Debentures:				
6.875 percent due 2011	80	79	81	82
8.75 percent due 2012	89	88	89	92
7.5 percent due 2015 (2)	766	616	764	737
8.375 percent due 2016 (3)	1,043	822	1,043	998
7.125 percent due 2018	172	116	172	140
7.75 percent due 2019	1,100	758	1,100	950
7.625 percent due 2026	171	103	171	119
Subordinated Debentures payable to affiliates, 8.316 percent, due 2027	200	108	200	107
PPEA Credit Agreement Facility, floating rate, due 2010 (4)	—	—	644	334
PPEA Tax Exempt Bonds, floating rate, due 2036 (4)	—	—	100	100
Sithe Senior Notes, 9.0 percent due 2013 (5)	267	260	300	294
Other—DHI (6)	290	290	8	8
Other—Dynegy (7)	15	15	1	1

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

(2) Includes unamortized discounts of $19 million and $21 million at June 30, 2010 and December 31, 2009, respectively.

(3) Includes unamortized discounts of $4 million at June 30, 2010 and December 31, 2009.

(4) As discussed in Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities, effective January 1, 2010, we deconsolidated our investment in PPEA Holding, and as a result, PPEA's debt is no longer included in our unaudited condensed consolidated balance sheets.

(5)

Includes unamortized premiums of $10 million and $13 million at June 30, 2010 and December 31, 2009, respectively.

(6) Other represents short-term investments, including $86 million of short-term investments included in the Broker margin account.

(7) Other represents short-term investments.

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Note 7—Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, is included in Dynegy's and DHI's stockholders' equity on our unaudited condensed consolidated balance sheets as follows:

	June 30, 2010	December 31, 2009
	(in millions)	
Cash flow hedging activities, net	$3	$(24)
Unrecognized prior service cost and actuarial loss, net	(57)	(59)
Accumulated other comprehensive loss—unconsolidated investments, net (1)	(17)	—
Accumulated other comprehensive loss, net of tax	(71)	(83)
Less: Accumulated other comprehensive income attributable to the noncontrolling interests (1)	—	67
Accumulated other comprehensive loss attributable to Dynegy and DHI, net of tax	$(71)	$(150)

(1) As discussed in Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities, effective January 1, 2010, we deconsolidated our investment in PPEA Holding, and as a result, there are no longer any noncontrolling interests in any of our consolidated subsidiaries.

Note 8—Variable Interest Entities

Hydroelectric Generation Facilities. In 2005, Dynegy acquired, as part of a larger purchase, four hydroelectric generation facilities in Pennsylvania, two of which we still own. The entities owning these facilities meet the definition of VIEs. In accordance with the purchase agreement, Exelon Corporation ("Exelon") has the sole and exclusive right to direct our efforts to decommission, sell, or otherwise dispose of the hydroelectric facilities owned through the VIEs. Exelon is obligated to reimburse us for all costs, liabilities, and obligations of the entities owning these facilities, and to indemnify us with respect to the past and present assets and operations of the entities. As a result, we are not the primary beneficiary of the entities and have not consolidated them. There was no material change in our relationship with these entities during the three and six months ended June 30, 2010. Please see Note 14—Variable Interest Entities—Hydroelectric Generation Facilities in our Form 10-K for discussion of these entities.

PPEA Holding Company LLC. We own an approximate 37 percent interest in PPEA Holding, which through PPEA, its wholly-owned subsidiary, owns an approximate 57 percent undivided interest in the Plum Point Project, a power plant under construction in Mississippi County, Arkansas. PPEA is financing its share of construction costs through debt financing. Our obligation to PPEA Holding was limited to our funding commitment of approximately $15 million. As described below, this amount was paid in May 2010; accordingly, we have no future funding obligations related to PPEA Holding.

PPEA previously had a waiver for certain covenants required by its credit agreement. This waiver expired on March 12, 2010. As a result, PPEA is currently in default under its credit agreement. Please read Note 17—Debt—Plum Point of our Form 10-K for further discussion. In addition, Ambac, the guarantor of PPEA's interest rate swaps, filed for rehabilitation on March 24, 2010. As a result, PPEA is also in default under the terms of the interest rate swap agreements. Please read Note 7—Risk Management Activities, Derivatives and Financial Instruments of our Form 10-K for further discussion. On March 30, 2010, the lenders requested that PPEA post collateral of approximately $101 million. PPEA did not have the liquidity to provide this collateral and did not comply with the request. The lenders have not funded any borrowing requests since April 2010. PPEA has continued funding its portion of the construction costs with cash received from its sponsors, which includes the $15 million funded by us in May 2010, as well as existing cash related to PPEA tax exempt bonds. There can be no assurance that the lenders will fund future borrowing requests or as to the potential impact of any such refusal to fund on the Plum Point Project.

The carrying amount and classification of the amounts related to our investment in PPEA Holding included in our unaudited condensed consolidated balance sheet as of June 30, 2010 are included in the table below:

	June 30, 2010 (in millions)
Unconsolidated investments	$ —
Accumulated other comprehensive loss, net of tax	17

As stated above, PPEA's credit facility is currently in default which provides the lenders the right to (i) cancel all commitments and elect not to make any additional loans under the credit facility; (ii) demand immediate payment of all accrued and unpaid interest and principal; and/or (iii) take possession of PPEA's interest in the Plum Point Project and related collateral. Due to the uncertainty and risk surrounding PPEA's financing structure as a result of events that occurred in March 2010, we concluded that there was an other-than-temporary impairment of our investment in PPEA Holding and fully impaired our equity investment at March 31, 2010. As a result, we recorded an impairment charge of approximately $37 million, which is included in Losses from unconsolidated investments in our unaudited condensed consolidated statements of operations. Although our investment has been fully impaired, our maximum exposure to an accounting loss as a result of our investment in PPEA Holding is approximately $17 million, the amount currently deferred in Accumulated other comprehensive loss. We have now satisfied our obligation to provide support to PPEA discussed previously. The impairment is a Level 3 non-recurring fair value measurement and reflects our best estimate of third party market participants' considerations including probabilities related to restructuring of the project debt and potential insolvency. Please read Note 6—Fair Value Measurements for further discussion.

Please read Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities for further discussion. There are no cross-default provisions related to the PPEA credit facility and our Credit Facility and other long-term debt.

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Summarized aggregate financial information for our unconsolidated equity investment in PPEA Holding and our equity share thereof was:

	Three Months Ended June 30, 2010	
	Total	Equity Share
	(in millions)	
Revenues	$ —	$ —
Operating loss	(1)	—
Net loss	(42)	—

	Six Months Ended June 30, 2010	
	Total	Equity Share
	(in millions)	
Revenues	$ —	$ —
Operating loss	(2)	—
Net income (loss)	(33)	3

During the second quarter, we did not recognize our share of losses from our investment in PPEA Holding as our investment in PPEA Holding was valued at zero at June 30, 2010, and we do not have an obligation to provide further financial support.

Losses from unconsolidated investments for the six months ended June 30, 2010 were $34 million, which includes an impairment loss of $37 million, discussed above. This impairment was partially offset by equity earnings of $3 million, comprised primarily of mark-to-market gains related to PPEA's interest rate swaps, partly offset by financing expenses.

DLS Power Holdings and DLS Power Development. In December 2008, Dynegy executed an agreement with LS Associates to dissolve DLS Power Holdings and DLS Power Development effective January 1, 2009. Under the terms of the dissolution, Dynegy acquired exclusive rights, ownership and developmental control of substantially all repowering or expansion opportunities related to its existing portfolio of operating assets. In the first quarter 2009, Dynegy subsequently contributed these assets to DHI. LS Associates received approximately $19 million in cash from Dynegy on January 2, 2009, and acquired full ownership and developmental rights associated with various "greenfield" power generation and transmission development projects not related to Dynegy's then existing operating portfolio of assets.

Note 9—Debt

Contingent LC Facility. On May 21, 2010, DHI executed a new $150 million unsecured bilateral contingent letter of credit facility ("Contingent LC Facility") with Morgan Stanley Capital Group Inc. to provide DHI access to liquidity to support collateral posting requirements. Availability under the Contingent LC Facility is tied to increases in 2012 forward spark spreads and power prices. A facility fee will accrue on the unutilized portion of the facility at an annual rate of 0.60 percent and letter of credit availability fees will accrue at an annual rate of 7.25 percent. The facility will mature on December 31, 2012. No amounts were available under this facility at June 30, 2010.

Note 10—Related Party Transactions

We previously held two investments in joint ventures in which LS Power or its affiliates were also investors. DHI had 50 percent ownership interests in SCEA and SC Services, and subsidiaries of LS Power held the remaining 50 percent interests. On November 30, 2009, we completed our previously announced agreement to sell our interests in SCH and SC Services to LS Power. Please see Note 14—Variable Interest Entities—Sandy Creek Project in our Form 10-K for further discussion.

We also previously held two other investments in joint ventures in which LS Power or its affiliates were also investors. Dynegy had 50 percent ownership interests in DLS Power Holdings and DLS Power Development. Effective January 1, 2009, Dynegy and LS Power Associates, L.P. agreed to dissolve the two companies' development joint venture.

Under the terms of the dissolution, Dynegy acquired exclusive rights, ownership and developmental control of substantially all repowering or expansion opportunities related to its existing portfolio of operating assets, and subsequently contributed approximately $15 million of these assets and approximately $21 million of deferred tax assets associated with these assets to DHI. Please read Note 14—Variable Interest Entities—DLS Power Holdings and DLS Power Development for further discussion. As a result of the LS Power Transaction, as discussed in Note 4—Dispositions, Contract Terminations and Discontinued Operations—Dispositions and Contract Terminations—LS Power Transactions in our Form 10-K, effective November 30, 2009, LS Power is no longer considered a related party.

Other. On January 8, 2009, DHI paid a dividend of $175 million to Dynegy.

Note 11—Dynegy's Loss Per Share

Basic loss per share represents the amount of losses for the period available to each share of Dynegy's common stock outstanding during the period. Diluted loss per share represents the amount of losses for the period available to each share of Dynegy's common stock outstanding during the period plus each share that would have been outstanding assuming the issuance of common shares for all dilutive potential common shares outstanding during the period. Basic and diluted shares outstanding have been calculated to reflect the 1-for-5 reverse stock split for all periods presented. Please read Note 15—Capital Stock for further discussion.

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The reconciliation of basic loss per share from continuing operations to diluted loss per share from continuing operations is shown in the following table:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in millions, except per share amounts)			
Loss from continuing operations	$(191)	$(348)	$(47)	$(671)
Less: Net loss attributable to the noncontrolling interests	—	(1)	—	(3)
Loss from continuing operations attributable to Dynegy Inc. for basic and diluted loss per share	$(191)	$(347)	$(47)	$(668)
Basic weighted-average shares	120	168	120	168
Effect of dilutive securities:				
Stock options and restricted stock	1	1	1	1
Diluted weighted-average shares	121	169	121	169
Loss per share from continuing operations attributable to Dynegy Inc.:				
Basic	$(1.59)	$(2.06)	$(0.39)	$(3.98)
Diluted (1)	$(1.59)	$(2.06)	$(0.39)	$(3.98)

(1) Entities with a net loss from continuing operations are prohibited from including potential common shares in the computation of diluted per-share amounts. Accordingly, Dynegy Inc. has utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the three and six months ended June 30, 2010 and 2009.

Note 12—Commitments and Contingencies

Legal Proceedings

Set forth below is a summary of our material ongoing legal proceedings. We record reserves for contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable. In addition, we disclose matters for which management believes a material loss is at least reasonably possible. In all instances, management has assessed the matters below based on current information and made a judgment concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of damages sought and the probability of success. Management's judgment may prove materially inaccurate and such judgment is made subject to the known uncertainty of litigation.

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

- In February 2007, the Tennessee state court dismissed a class action on defendants' motion. Plaintiffs appealed and, in October 2008, the appellate court reversed the dismissal. Thereafter, defendants appealed to the Tennessee Supreme Court which, in April 2010, reversed the appellate court ruling and dismissed all of plaintiffs' claims. The decision is subject to appeal to the U.S. Supreme Court.

- In February 2008, the United States District Court in Las Vegas, Nevada granted defendants' motion for summary judgment in a Colorado class action and, ultimately, dismissed the case and all of plaintiffs' claims. The decision is subject to appeal once the remaining defendants' claims are adjudicated.

- The remaining five cases, three of which seek class certification, are also pending in Nevada federal court. All of the cases contain similar claims that individually, and in conjunction with other energy companies, we engaged in an illegal scheme to inflate natural gas prices in four states by providing false information to natural gas index publications. In November 2009, following defendants' motion for reconsideration, the court invited defendants to renew their motions for summary judgment, which were filed shortly thereafter. Now fully briefed, we await an order or further instruction from the court. In the interim, discovery and plaintiffs' class certification motion are stayed.

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

Cooling Water Intake Permits. The cooling water intake structures at several of our power generation facilities are regulated under section 316(b) of the Clean Water Act. This provision generally requires that standards set for power generation facilities require that the location, design, construction and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact. These standards are developed and implemented for power generating facilities through the NPDES permits or individual SPDES permits on a case by case basis.

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

- Roseton SPDES Permit — In April 2005, the NYSDEC issued a Draft SPDES Permit renewal for the Roseton plant. The permit is opposed by environmental groups challenging the BTA determination. The hearing will be scheduled after the Commissioner rules on appeals of procedural matters. We believe that the petitioners' claims lack merit and we plan to oppose those claims vigorously.

- Moss Landing NPDES Permit — The California Regional Water Quality Control Board ("Water Board") issued an NPDES permit for the Moss Landing power generating facility in 2000 that did not require closed cycle cooling. A local environmental group challenged the BTA determination of the permit. The Water Board's decision was affirmed by the Superior Court in 2004 and by the Court of Appeals in 2007. The Supreme Court of California granted review in March 2008. The petitioner's brief was filed in December 2009. We filed a motion to dismiss and our responsive brief in March 2010. The petitioner's reply brief was filed in May 2010. Our motion to dismiss was denied in June 2010. In July 2010, the California Energy Commission filed an application for leave to file a brief in support of our argument challenging the jurisdiction of the Supreme Court. We believe that petitioner's claims lack merit and we plan to continue to oppose those claims vigorously.

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

Native Village of Kivalina and City of Kivalina v. ExxonMobil Corporation, et al. In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska initiated an action in federal court in the Northern District of California against DHI and 23 other companies in the energy industry. Plaintiffs claim that defendants' emissions of GHG including CO2 contribute to climate change and have caused significant damage to a native Alaskan Eskimo village through increased vulnerability to waves, storm surges and erosion. In September 2009, the court dismissed all of the plaintiffs' claims based on lack of subject matter jurisdiction and because plaintiffs lacked standing to bring the suit. Shortly thereafter, plaintiffs appealed to the Ninth Circuit. The parties have filed their initial briefs and plaintiffs' reply brief is due in September 2010. We believe the plaintiffs' suit lacks merit and we will continue to oppose their claims vigorously.

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

Guarantees and Indemnifications

In the ordinary course of business, we routinely enter into contractual agreements that contain various representations, warranties, indemnifications and guarantees. Examples of such agreements include, but are not limited to, service agreements, equipment purchase agreements, engineering and technical service agreements, asset sales and procurement and construction contracts. Some agreements contain indemnities that cover the other party's negligence or limit the other party's liability with respect to third party claims, in which event we will effectively be indemnifying the other party. Virtually all such agreements contain representations or warranties that are covered by indemnifications against the losses incurred by the other parties in the event such representations and warranties are false. While there is always the possibility of a loss related to such representations, warranties, indemnifications and guarantees in our contractual agreements, and such loss could be significant, in most cases management considers the probability of loss to be remote. Related to the indemnifications discussed below, we have accrued an aggregate of approximately $2 million as of June 30, 2010.

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

West Coast Power Indemnities. In connection with the sale of our 50 percent interest in West Coast Power to NRG on March 31, 2006, an agreement was executed to allocate responsibility for managing certain litigation and provide for certain indemnities with respect to such litigation. The indemnification agreement in relevant part provides that NRG assumes responsibility for all defense costs and any risk of loss, subject to certain conditions and limitations, arising from a February 2002 complaint filed at FERC by the California Public Utilities Commission alleging that several parties, including West Cost Power subsidiaries, overcharged the State of California for wholesale power. FERC found the rates charged by wholesale suppliers to be just and reasonable. However, this matter was appealed to the U.S. Supreme Court, which remanded the case to FERC for further review.

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

Illinois Power Indemnities. Dynegy has indemnified third parties against losses resulting from possible adverse regulatory actions taken by the ICC that could prevent Illinois Power from recovering costs incurred in connection with purchased natural gas and investments in specified items. Although there is no absolute limitation on Dynegy's liability under this indemnity, the amount of the indemnity is limited to 50 percent of any such losses. Dynegy has made certain payments in respect of these indemnities following regulatory action by the ICC, and has established reserves for further potential indemnity claims. Further events, which fall within the scope of the indemnity, may still occur. However, Dynegy is not required to accrue a liability in connection with these indemnifications, as management cannot reasonably estimate a range of outcomes or at this time considers the probability of an adverse outcome as only reasonably possible. Dynegy intends to contest any proposed regulatory actions.

Black Mountain Guarantee. Through one of our subsidiaries, we hold a 50% ownership interest in Black Mountain (Nevada Cogeneration) ("Black Mountain"), in which our partner is a Chevron subsidiary. Black Mountain owns the Black Mountain power generation facility and has a power purchase agreement with a third party that extends through April 2023. In connection with the power purchase agreement, pursuant to which Black Mountain receives payments which decrease in amount over time, we agreed to guarantee 50 percent of certain payments that may be due to the power purchaser under a mechanism designed to protect it from early termination of the agreement. At June 30, 2010, if an event of default due to early termination had occurred under the terms of the mortgage on the facility entered into in connection with the power purchase agreement, we could have been required to pay the power purchaser approximately $55 million under the guarantee.

Other Indemnities. We entered into indemnifications regarding environmental, tax, employee and other representations when completing asset sales such as, but not limited, to the Rolling Hills, Calcasieu, CoGen Lyondell and Heard County power generating facilities. As of June 30, 2010, no claims have been made against these indemnities. There is no limitation on our liability under certain of these indemnities. However, management is unaware of any existing claims.

Note 13—Employee Compensation, Savings and Pension Plans

We have various defined benefit pension plans and post-retirement benefit plans in which our past and present employees participate, which are more fully described in Note 21—Employee Compensation, Savings and Pension Plans in our Form 10-K.

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

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
	2010	2009	2010	2009

	(in millions)			
Service cost benefits earned during period	$ 3	$ 3	$ —	$ —
Interest cost on projected benefit obligation	4	3	1	1
Expected return on plan assets	(4)	(4)	—	—
Recognized net actuarial loss	1	1	—	—
Net periodic benefit cost	$ 4	$ 3	$ 1	$ 1

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
	2010	2009	2010	2009
	(in millions)			
Service cost benefits earned during period	$ 6	$ 6	$ 1	$ 1
Interest cost on projected benefit obligation	7	6	2	2
Expected return on plan assets	(8)	(7)	—	—
Recognized net actuarial loss	2	2	—	—
Net periodic benefit cost	$ 7	$ 7	$ 3	$ 3

Contributions. During the six months ended June 30, 2010, we made $6 million in contributions to our pension plans and other postretirement benefit plans. We made $3 million in contributions to our pension plans and other postretirement benefit plans during the six months ended June 30, 2009. We expect to make contributions of approximately $19 million to our pension plans and $2 million to other benefit plans during 2010.

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Note 14—Income Taxes

Effective Tax Rate. We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income or loss, except for significant unusual or extraordinary transactions. Income taxes for significant unusual or extraordinary transactions are computed and recorded in the period that the specific transaction occurs. Dynegy's income taxes included in continuing operations were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in millions, except rates)			
Income tax benefit	$ 128	$ 204	$ 63	$ 113
Effective tax rate	40 %	37 %	57 %	14 %

For the six months ended June 30, 2010, Dynegy's overall effective tax rate on continuing operations was different than the statutory rate of 35 percent due primarily to a benefit of $18 million related to the release of reserves for uncertain tax positions, partly offset by the impact of state taxes. For the three and six months ended June 30, 2010, Dynegy's overall effective tax rate on continuing operations was different than the statutory rate of 35 percent due primarily to the impact of state taxes. For the six months ended June 30, 2009, Dynegy's overall effective tax rate on continuing operations was different than the statutory rate of 35 percent due primarily to nondeductible goodwill. Additionally, a change in state income tax law resulted in additional income tax expense of approximately $21 million. As a result of the LS Power Transactions, we revised our assumptions around the ability to utilize certain state deferred tax assets, and therefore we recorded valuation allowances resulting in additional state tax expense of $10 million for the three and six months ended June 30, 2009.

DHI's income taxes included in continuing operations were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in millions, except rates)			
Income tax benefit	$ 128	$ 205	$ 56	$ 117
Effective tax rate	40 %	37 %	51 %	15 %

For the six months ended June 30, 2010, DHI's overall effective tax rate on continuing operations was different than the statutory rate of 35 percent due primarily to a benefit of $12 million related to the release of reserves for uncertain tax positions, partly offset by the impact of state taxes. For the three and six months ended June 30, 2010, Dynegy's overall effective tax rate on continuing operations was different than the statutory rate of 35 percent due primarily to the impact of state taxes. For the six months ended June 30, 2009, DHI's overall effective tax rate on continuing operations was different than the statutory rate of 35 percent due primarily to nondeductible goodwill. Additionally, a change in state income tax law resulted in additional income tax expense of approximately $15 million. As a result of the LS Power Transactions, we revised our assumptions around the ability to utilize certain state deferred tax assets, and therefore we recorded valuation allowances resulting in additional state tax expense of $7 million for the three and six months ended June 30, 2009.

Note 15—Capital Stock

At June 30, 2010, Dynegy had authorized capital stock consisting of 420,000,000 shares of common stock, $0.01 par value per share, and 20,000,000 of preferred stock, $0.01 per value per share. As of June 30, 2010, there were no shares of preferred stock issued or outstanding.

Common Stock. On May 25, 2010, Dynegy effected a reverse stock split of its outstanding common stock at a ratio of 1-for-5 and proportionately decreased the number of authorized shares of its capital stock. As a result, Dynegy's authorized capital decreased from 2,100,000,000 shares of common stock to 420,000,000 shares of common stock and its issued and outstanding shares of common stock decreased on May 25, 2010 from 605,192,308 shares of common stock to 121,032,255 shares of common stock.

In addition, the December 31, 2009 condensed consolidated balance sheet was adjusted in this report to reflect the impact of the reverse stock split so that the basis of presentation is consistent. As a result, Dynegy's authorized capital was adjusted from 2,100,000,000 shares of common stock to 420,000,000 shares of common stock and its issued and outstanding shares of common stock as of December 31, 2009 was adjusted from 603,577,577 shares of common stock to 120,715,515 shares of common stock.

Treasury Stock. As a result of the reverse stock split, the number of common stock shares of Dynegy held as treasury stock at May 25, 2010 decreased from 3,137,959 shares to 627,591 shares. The condensed consolidated balance sheet was adjusted for all periods presented for the 1-for-5 reverse stock split.

In addition, the December 31, 2009 condensed consolidated balance sheet was adjusted in this report to reflect the impact of the reverse stock split so that the basis of presentation is consistent. As a result, Dynegy's shares of treasury stock as of December 31, 2009 was adjusted from 2,788,383 shares to 557,677 shares.

Note 16—Segment Information

We report results for the following segments: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Our unaudited condensed consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization.

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Reportable segment information for Dynegy, including intercompany transactions accounted for at prevailing market rates, for the three and six months ended June 30, 2010 and 2009 is presented below:

Dynegy's Segment Data as of and for the Three Months Ended June 30, 2010
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$63	$71	$105	$—	$239
Total revenues	$63	$71	$105	$—	$239
Depreciation and amortization	$(63)	$(17)	$(8)	$(2)	$(90)
Impairment and other charges	—	—	(1)	—	(1)
Operating loss	$(165)	$(9)	$(26)	$(29)	$(229)
Other items, net	—	—	—	1	1
Interest expense					(91)
Loss from continuing operations before income taxes					(319)
Income tax benefit					128
Net loss					$(191)
Identifiable assets:					
Domestic	$5,282	$2,112	$1,768	$1,410	$10,572
Other	—	—	—	24	24
Total	$5,282	$2,112	$1,768	$1,434	$10,596
Capital expenditures and investments in unconsolidated affiliates	$(108)	$(2)	$(2)	$(3)	$(115)

Dynegy's Segment Data as of and for the Three Months Ended June 30, 2009
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$ 170	$ 100	$ 181	$ (1)	$ 450

Total revenues	$ 170	$ 100	$ 181	$ (1)	$ 450
Depreciation and amortization	$ (57)	$ (13)	$ (16)	$ (3)	$ (89)
Impairment and other charges	—	—	(387)	—	(387)
Operating income (loss)	$ (68)	$ 29	$ (382)	$ (50)	$ (471)
Earnings from unconsolidated investments	—	13	—	—	13
Other items, net	—	2	—	2	4
Interest expense					(98)
Loss from continuing operations before income taxes					(552)
Income tax benefit					204
Loss from continuing operations					(348)
Income from discontinued operations, net of taxes					2
Net loss					(346)
Less: Net loss attributable to the noncontrolling interests					(1)
Net loss attributable to Dynegy Inc.					$ (345)
Identifiable assets:					
Domestic	$ 7,075	$ 2,946	$ 1,986	$ 1,514	$ 13,521
Other	—	—	—	19	19
Total	$ 7,075	$ 2,946	$ 1,986	$ 1,533	$ 13,540
Capital expenditures	$ (146)	$ (7)	$ (11)	$ (1)	$ (165)

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Dynegy's Segment Data as of and for the Six Months Ended June 30, 2010
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$549	$214	$334	$—	$1,097
Total revenues	$549	$214	$334	$—	$1,097
Depreciation and amortization	$(113)	$(33)	$(16)	$(3)	$(165)
Impairment and other charges	—	—	(1)	—	(1)
Operating income (loss)	$95	$36	$34	$(63)	$102
Losses from unconsolidated investments	(34)	—	—	—	(34)
Other items, net	—	—	1	1	2
Interest expense					(180)
Loss from continuing operations before income taxes					(110)
Income tax benefit					63
Loss from continuing operations					(47)
Income from discontinued operations, net of taxes					1
Net loss					$(46)
Identifiable assets:					
Domestic	$5,282	$2,112	$1,768	$1,410	$10,572
Other	—	—	—	24	24
Total	$5,282	$2,112	$1,768	$1,434	$10,596
Capital expenditures and investments in unconsolidated affiliates	$(197)	$(10)	$(5)	$(4)	$(216)

Dynegy's Segment Data as of and for the Six Months Ended June 30, 2009
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					

Domestic	$694	$183	$478	$(1)	$1,354
Total revenues	$694	$183	$478	$(1)	$1,354
Depreciation and amortization	$(108)	$(30)	$(31)	$(6)	$(175)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairments and other charges	—	—	(387)	—	(387)
Operating income (loss)	$138	$(243)	$(425)	$(87)	$(617)
Earnings from unconsolidated investments	—	20	—	1	21
Other items, net	2	2	—	4	8
Interest expense					(196)
Loss from continuing operations before income taxes					(784)
Income tax benefit					113
Loss from continuing operations					(671)
Loss from discontinued operations, net of taxes					(12)
Net loss					(683)
Less: Net loss attributable to the noncontrolling interests					(3)
Net loss attributable to Dynegy Inc.					$(680)
Identifiable assets:					
Domestic	$7,075	$2,946	$1,986	$1,514	$13,521
Other	—	—	—	19	19
Total	$7,075	$2,946	$1,986	$1,533	$13,540
Capital expenditures	$(274)	$(8)	$(18)	$(3)	$(303)

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Reportable segment information for DHI, including intercompany transactions accounted for at prevailing market rates, for the three and six months ended June 30, 2010 and 2009 is presented below:

DHI's Segment Data as of and for the Three Months Ended June 30, 2010
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$ 63	$ 71	$ 105	$ —	$ 239
Total revenues	$ 63	$ 71	$ 105	$ —	$ 239
Depreciation and amortization	$ (63)	$ (17)	$ (8)	$ (2)	$ (90)
Impairment and other charges	—	—	(1)	—	(1)
Operating income (loss)	$ (165)	$ (9)	$ (26)	$ (29)	$ (229)
Other items, net	—	—	—	1	1
Interest expense					(91)
Loss from continuing operations before income taxes					(319)
Income tax benefit					128
Net loss					$ (191)
Identifiable assets:					
Domestic	$ 5,282	$ 2,112	$ 1,768	$ 1,353	$ 10,515
Other	—	—	—	24	24
Total	$ 5,282	$ 2,112	$ 1,768	$ 1,377	$ 10,539
Capital expenditures and investments in unconsolidated affiliates	$ (108)	$ (2)	$ (2)	$ (3)	$ (115)

DHI's Segment Data as of and for the Three Months Ended June 30, 2009
(in millions)

Power Generation				
GEN-MW	GEN-WE	GEN-NE	Other	Total

Unaffiliated revenues:					
Domestic	$170	$100	$181	$(1)	$450
Total revenues	$170	$100	$181	$(1)	$450
Depreciation and amortization	$(57)	$(13)	$(16)	$(3)	$(89)
Impairment and other charges	—	—	(387)	—	(387)
Operating income (loss)	$(68)	$29	$(382)	$(50)	$(471)
Earnings from unconsolidated investments	—	13	—	—	13
Other items, net	—	2	—	1	3
Interest expense					(98)
Loss from continuing operations before income taxes					(553)
Income tax benefit					205
Loss from continuing operations					(348)
Income from discontinued operations, net of taxes					12
Net loss					(336)
Less: Net loss attributable to the noncontrolling interests					(1)
Net loss attributable to Dynegy Holdings Inc.					$(335)
Identifiable assets:					
Domestic	$7,075	$2,946	$1,986	$1,332	$13,339
Other	—	—	—	19	19
Total	$7,075	$2,946	$1,986	$1,351	$13,358
Capital expenditures	$(146)	$(7)	$(11)	$(1)	$(165)

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DHI's Segment Data as of and for the Six Months Ended June 30, 2010
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Unaffiliated revenues:					
Domestic	$549	$214	$334	$—	$1,097
Total revenues	$549	$214	$334	$—	$1,097
Depreciation and amortization	$(113)	$(33)	$(16)	$(3)	$(165)
Impairment and other charges	—	—	(1)	—	(1)
Operating income (loss)	$95	$36	$34	$(63)	$102
Losses from unconsolidated investments	(34)	—	—	—	(34)
Other items, net	—	—	1	1	2
Interest expense					(180)
Loss from continuing operations before income taxes					(110)
Income tax benefit					56
Loss from continuing operations					(54)
Income from discontinued operations, net of taxes					1
Net loss.					$(53)
Identifiable assets:					
Domestic	$5,282	$2,112	$1,768	$1,353	$10,515
Other	—	—	—	24	24
Total	$5,282	$2,112	$1,768	$1,377	$10,539
Capital expenditures and investments in unconsolidated affiliates	$(197)	$(10)	$(5)	$(4)	$(216)

DHI's Segment Data as of and for the Six Months Ended June 30, 2009
(in millions)

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total

Unaffiliated revenues:					
Domestic	$694	$183	$478	$(1)	$1,354
Total revenues	$694	$183	$478	$(1)	$1,354
Depreciation and amortization	$(108)	$(30)	$(31)	$(6)	$(175)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairments and other charges	—	—	(387)	—	(387)
Operating income (loss)	$138	$(243)	$(425)	$(89)	$(619)
Earnings from unconsolidated investments	—	20	—	—	20
Other items, net	2	2	—	3	7
Interest expense					(196)
Loss from continuing operations before income taxes					(788)
Income tax benefit					117
Loss from continuing operations					(671)
Loss from discontinued operations, net of taxes					(2)
Net loss					(673)
Less: Net loss attributable to the noncontrolling interests					(3)
Net loss attributable to Dynegy Holdings Inc.					$(670)
Identifiable assets:					
Domestic	$7,075	$2,946	$1,986	$1,332	$13,339
Other	—	—	—	19	19
Total	$7,075	$2,946	$1,986	$1,351	$13,358
Capital expenditures	$(274)	$(8)	$(18)	$(3)	$(303)

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DYNEGY INC. and DYNEGY HOLDINGS INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS

For the Interim Periods Ended June 30, 2010 and 2009

Item 2—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—DYNEGY INC. AND DYNEGY HOLDINGS INC.

The following discussion should be read together with the unaudited condensed consolidated financial statements and the notes thereto included in this report and with the audited consolidated financial statements and the notes thereto included in our Form 10-K.

We are holding companies and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as three separate segments in our consolidated financial statements: (i) the Midwest segment ("GEN-MW"); (ii) the West segment ("GEN-WE"); and (iii) the Northeast segment ("GEN-NE"). Our unaudited condensed consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization.

Recent Developments

Contingent LC Facility. On May 21, 2010, DHI entered into a new $150 million Contingent LC Facility with Morgan Stanley Capital Group Inc. Availability under the Contingent LC Facility is tied to increases in 2012 forward spark spreads and power prices. Management believes the Contingent LC Facility represents a cost-effective supplement to its liquidity position and will facilitate opportunistic commercial activities in what would be a rising price environment. A facility fee will accrue on the unutilized portion of the facility at an annual rate of 0.60 percent and letter of credit availability fees will accrue at an annual rate of 7.25 percent. The facility will mature on December 31, 2012. No amounts were available under this facility at June 30, 2010.

Reverse Stock Split. On May 25, 2010, Dynegy effected a reverse stock split of its outstanding common stock at a ratio of 1-for-5 and proportionately decreased the number of authorized shares of its capital stock. The 2009 financial information in this report has been adjusted to reflect the impact of the reverse stock split on per share amounts and shares outstanding so that the basis of presentation is consistent with that of the 2010 financial information.

LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, collateral requirements, fixed capacity payments and contractual obligations, capital expenditures (including required environmental expenditures) and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated margin and collateral requirements, facility maintenance costs and other costs such as payroll.

Our primary sources of internal liquidity are cash flows from operations, cash on hand, and available capacity under our Credit Facility, of which the revolver capacity of $1,080 million is scheduled to mature in April 2012 and the term letter of credit capacity of $850 million is scheduled to mature in April 2013. Secondarily, we expect to continue utilizing both lien-secured commodity hedging arrangements, which reduce collateral requirements, and spark spread-contingent liquidity facilities, which increase potential liquidity availability. Additionally, DHI may borrow money from time to time from Dynegy. These internal liquidity sources, as they may be supplemented from time to time (including through the efforts regarding Credit Facility described in more detail below), are expected to be sufficient to fund the operation of our business, potential requirements to post additional collateral, as well as our planned capital expenditure program, including expenditures in connection with the Midwest Consent Decree, and debt service requirements over the next twelve months. Please read the discussion below regarding our Revolver Capacity, as well as Note 17—Debt—Credit Facility in our Form 10-K, for a discussion of the financial covenants contained in the Credit Facility.

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

Current Liquidity. The following table summarizes our consolidated revolver capacity and liquidity position at August 2, 2010, June 30, 2010 and December 31, 2009:

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	August 2, 2010	June 30, 2010	December 31, 2009
		(in millions)	
Revolver capacity (1)	$1,080	$1,080	$1,080
Borrowings against revolver capacity	—	—	—
Term letter of credit capacity, net of required reserves	825	825	825
Plum Point letter of credit capacity (2)	—	—	102
Available contingent letter of credit facility capacity (3)	—	—	—
Outstanding letters of credit (2)	(461)	(435)	(536)
Unused capacity	1,444	1,470	1,471
Cash—DHI	324	244	419
Short-term investments—DHI (4)	222	204	—
Total available liquidity—DHI	1,990	1,918	1,890
Cash—Dynegy	38	38	52
Short-term investments—Dynegy (4)	15	15	—
Total available liquidity—Dynegy	$2,043	$1,971	$1,942

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

(2) Reflects the reduction of $102 million of capacity and corresponding outstanding letters of credit as of March 31, 2010 due to the deconsolidation of PPEA Holding. Please read Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities for further discussion.

(3) Under the terms of the Contingent LC Facility, up to $150 million of capacity can become available, contingent on changes in spark spreads and power prices for 2012 forward spark spreads and power prices.

(4) We invest our available cash balances in certain investments permitted by our internal policies and external financing agreements. Please read Note 1—Accounting Policies—Short-Term Investments and Note 4—Investments for further discussion.

Cash on Hand. At August 2, 2010 and June 30, 2010, Dynegy had cash on hand of $362 million and $282 million, respectively, as compared to $471 million at December 31, 2009. The decrease in cash on hand through August 2, 2010 and June 30, 2010 as compared to the end of 2009 is primarily attributable to purchases of short-term investments and capital expenditures partly offset by the return of cash that was held in our Broker margin account.

Revolver Capacity. Based on management's current 2010 forecast and as discussed in our Form 10-K, a portion of DHI's available liquidity under the Credit Facility will likely be reduced during 2010 as a result of the application of the covenant regarding the ratio of secured debt to adjusted EBITDA (as defined therein). The effect of reduced availability under the Credit Facility, to the extent it is not later restored by favorable changes in the components of the ratio calculation, would be less available liquidity to DHI. However, we do not believe this reduction will have a material adverse effect on our ability to support our operations for the next twelve months. We expect to proactively amend, extend or refinance the Credit Facility within the next twelve months. Please read Note 17—Debt—Credit Facility in our Form 10-K for further discussion of our Credit Facility.

Operating Activities

Historical Operating Cash Flows. Dynegy's cash flow provided by operations totaled $368 million for the six months ended June 30, 2010. DHI's cash flow provided by operations totaled $369 million for the six months ended June 30, 2010. During the period, our power generation business provided positive cash flow from operations of $635 million from the operation of our power generation facilities, primarily reflecting positive earnings for the period and approximately $255 million of cash returned from our futures clearing manager. The return of this cash is partly the result of a $126 million decrease in our collateral requirements for the period; the remaining cash was returned as a result of the posting of short-term investments and a letter of credit in substitute of cash. Corporate and other operations included a use of approximately $267 million and $266 million in cash by Dynegy and DHI, respectively, primarily due to interest payments to service debt and general and administrative expenses.

Dynegy's cash flow provided by operations totaled $60 million for the six months ended June 30, 2009. DHI's cash flow provided by operations totaled $80 million for the six months ended June 30, 2009. During the period, our power generation business provided positive cash flow from operations of $338 million from the operation of our power generation facilities. Cash provided by the operations of our power generation facilities was partly offset by a $166 million increase in collateral postings, including 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. Corporate and other operations included a use of approximately $278 million and $258 million in cash by Dynegy and DHI, respectively, primarily due to interest payments to service debt and general and administrative expenses, partially offset by interest income. Dynegy's operating cash flow also reflected the payment of $19 million to LS Associates in conjunction with the dissolution of DLS Power Holdings and DLS Power Development.

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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 power, the price of natural gas and its correlation to power prices, the cost of coal and fuel oil, collateral requirements, the value of capacity and ancillary services, the run time of our generating facilities, the effectiveness of our commercial strategy, legal, environmental and regulatory requirements, our ability to achieve the cost savings contemplated in our 2010-2013 cost reduction program and our ability to capture value associated with commodity price volatility. Our future operating cash flows are not likely to materially improve absent significant improvement in commodity prices in the regions where we operate.

Collateral Postings. We use a significant portion of our capital resources, in the form of cash, short-term investments 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 business at August 2, 2010, June 30, 2010 and December 31, 2009:

	August 2, 2010	June 30, 2010	December 31, 2009
		(in millions)	
By Business:			
Generation	$481	$459	$637
Other (1)	88	88	190
Total	$569	$547	$827
By Type:			
Cash and short-term investments (2)	$108	$112	$291
Letters of credit (1)	461	435	536
Total	$569	$547	$827

(1) August 2, 2010 and June 30, 2010 reflect the reduction of $102 million of capacity and corresponding outstanding letters of credit due to the deconsolidation of PPEA Holding. Please read Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities for further discussion.

(2) Includes Collateral included in Broker margin account on our consolidated balance sheets at August 2, 2010, June 30, 2010 and December 31, 2009, respectively, as well as other collateral postings included in Prepayments and other current assets.

The change in letters of credit postings from December 31, 2009 to June 30, 2010 and to August 2, 2010 is related to a $102 million decrease due to the removal of the PPEA letter of credit as a result of the deconsolidation of PPEA Holding and lower commodity prices offset by an increase resulting from a $75 million letter of credit posted with our broker in substitute of cash. Cash collateral postings also decreased due to the letters of credit posted with our broker noted above as well as a reduction of margin requirements from the settlement of positions and lower commodity prices.

In addition to cash and letters of credit posted as collateral, we have granted additional permitted first priority liens on the assets currently subject to first priority liens under our Credit Facility as collateral under certain of our commodity derivative agreements in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to the counterparties under such agreements. The counterparties under such agreements would share the benefits of the collateral subject to such first priority liens ratably with the lenders under the Credit Facility. The fair value of our commodity derivatives collateralized by first priority liens, netted by counterparty, included liabilities of

$60 million, $60 million and $31 million at August 2, 2010, June 30, 2010 and December 31, 2009, respectively.

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

Investing Activities

Capital Expenditures. We continue to tightly manage our operating costs and capital expenditures. We had approximately $201 million and $303 million in capital expenditures during the six months ended June 30, 2010 and 2009. Our capital spending by reportable segment was as follows:

	For the Six Months Ended June 30,	
	2010	2009
	(in millions)	
GEN-MW	$ 182	$ 274
GEN-WE	10	8
GEN-NE	5	18
Other	4	3
Total	$ 201	$ 303

Capital spending in our GEN-MW segment primarily consisted of environmental and maintenance capital projects, as well as approximately $47 million spent on development capital related to the Plum Point Project during the six months ended June 30, 2009. Capital spending in our GEN-WE and GEN-NE segments primarily consisted of maintenance projects.

Asset Dispositions. Consistent with industry practice, we regularly evaluate our generation fleet based primarily on geographic location, fuel supply, market structure, market recovery expectations, regulatory or legislative risks and cash flows. We consider divestitures of assets where the balance of the above factors suggests that such assets' earnings potential is limited or that the benefits that can be captured through a divestiture outweigh the benefits of continuing to own and operate such assets. We have previously indicated that we consider our investment in PPEA Holding a non-core asset and intend to pursue alternatives regarding our remaining ownership interest. Additional asset divestures could be considered consistent with the criteria described above or to otherwise supplement our liquidity position.

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On April 30, 2009, we completed our sale of the Heard County power generation facility to Oglethorpe for approximately $105 million, net of transaction costs.

Other Investing Activities. Cash outflow related to purchases of short-term investments during the six months ended June 30, 2010 totaled $331 million and $316 million for Dynegy and DHI, respectively. Cash inflow related to distributions from short-term investments for the six months ended June 30, 2010 was $36 million. There was a $10 million cash outflow related to restricted cash balances during the six months ended June 30, 2010 due to an increase in the Independence restricted cash balance. There was a $15 million cash outflow related to our funding commitment obligation under the PPEA Sponsor Support Agreement.

Cash inflow related to short-term investments during the six months ended June 30, 2009 totaled $14 million and $13 million for Dynegy and DHI, respectively, reflecting distributions from our short-term investments. In addition, there was a $33 million cash outflow during the six months ended June 30, 2009 related to changes in restricted cash balances primarily due to a $39 million increase in the Independence restricted cash balance. Other included $3 million of insurance proceeds.

Financing Activities

Historical Cash Flow from Financing Activities. Dynegy's and DHI's net cash used in financing activities during the six months ended June 30, 2010 totaled $36 million due to $31 million of repayments of borrowings on our Sithe senior debt and $5 million of financing fees.

Dynegy's net cash provided by financing activities during the six months ended June 30, 2009 totaled $54 million, primarily related to proceeds from long-term borrowings under the Plum Point Credit Agreement Facility. DHI's net cash used in financing activities during the six months ended June 30, 2009 totaled $121 million. This included a one-time dividend payment from DHI to Dynegy of $175 million offset by $54 million primarily related to proceeds from long-term borrowings under the Plum Point Credit Agreement Facility.

Future Financing Activities. The revolver capacity under our Credit Facility is scheduled to mature in April 2012, and the term loan capacity is scheduled to mature in April 2013. In order to prudently provide for adequate long-term liquidity to support our business, among other reasons, within the next 12 months, we expect to proactively amend, extend or refinance these facilities in advance of their scheduled maturities. Actual timing will depend on a variety of factors, including general market receptiveness, the potential timing of other comparable transactions, and the adequacy and sufficiency of the current terms and conditions contained in the Credit Facility for meeting our capital and liquidity needs. There can be no assurance that such activities will result in amended, extended or refinanced facilities or as to our ability to continue to satisfy the covenants contained in such facilities in the absence of such amendment, extension or refinancing thereof.

Financing Trigger Events. Our debt instruments and other financial obligations include provisions which, if not met, could require early payment, additional collateral support or similar actions. These trigger events include financial covenants, insolvency events, defaults on scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. We do not have any trigger events tied to specified Dynegy or DHI credit ratings or Dynegy's stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events.

Financial Covenants. Our Credit Facility contains certain financial covenants, including (i) a covenant (measured as of the last day of the relevant fiscal quarter) that requires DHI and certain of its subsidiaries to maintain a ratio of secured debt to adjusted EBITDA (each as defined therein) for DHI and its relevant subsidiaries of no greater than a specified amount; and (ii) a covenant that requires DHI and certain of its subsidiaries to maintain a ratio of Adjusted

EBITDA to Interest Expense (each as defined therein) for DHI and its relevant subsidiaries as of the last day of the measurement periods as specified below of no less than a specified amount.

We are in compliance with these covenants as of June 30, 2010, although we expect a temporary reduction in available revolver capacity later in 2010. Please read “Revolver Capacity” above for further discussion.

Depressed power prices may make covenant compliance more difficult to meet absent an improving trend in demand for power and/or commodity market pricing and consequent financial performance, particularly as the Adjusted EBITDA to Interest Expense covenant ratio requirements increase over the course of 2011 and into 2012. A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements could result in reduced borrowing capacity or even a default, causing our debt obligations under such financing agreements (and any other indebtedness to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable. If we are unable to cure any such default, obtain a waiver or a replacement financing, and those lenders accelerate the payment of such indebtedness, in the case that we are unable to repay those amounts, the holders of the indebtedness under our secured debt obligations would be entitled to foreclose on, and acquire control of substantially all of our assets, which would have a material adverse impact on our financial condition, results of operations and cash flows. However, as discussed in “Future Financing Activities” above, within the next 12 months we expect to proactively amend, extend or refinance the Credit Facility, including any prudent potential modifications to existing financial covenants, to the extent we deem it advisable or necessary.

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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 with respect to capital stock. Please read Note 17—Debt—Credit Facility in our Form 10-K for further discussion of our Credit Facility.

Capital-Structuring Transactions. From time to time, we may explore additional sources of external liquidity, including public or private debt or equity issuances, to improve our credit profile, supplement our liquidity position and/or better position our operating portfolio relative to forward views of commodity prices. Matters to be considered would include cash interest expense, covenant flexibility and maturity profile, all to be balanced with maintaining adequate liquidity. The receptiveness of the capital markets to an offering of debt or equity securities cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control, including current market conditions. Any issuance of equity by Dynegy likely would have other effects as well, including stockholder dilution, and our ability to issue debt securities is limited by our financing agreements, including our Credit Facility.

In addition, we continually review and discuss opportunities to participate in the ongoing consolidation of the power generation industry or otherwise seek to enhance long-term value for Dynegy's stockholders. No 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.

Dividends and 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 during the second quarter 2010, and does not expect to pay a dividend on its common stock in the foreseeable future.

Credit Ratings

Our credit rating status is currently "non-investment grade"; our senior unsecured debt is rated "B-" by Standard & Poor's, "B3" by Moody's, and "B" by Fitch. On April 12, 2010, Standard & Poor's downgraded our corporate family ratings to "B-" from "B" based on projected lower commodity prices affecting credit metrics. The agency also reduced our senior secured bank facilities rating to "B+" from "BB-", and senior unsecured debt rating to "B-" from "B". On April 6, 2010, Moody's issued a rating action placing Dynegy's credit rating under review for possible downgrade. On July 1, 2010, Moody's issued a rating action to conclude their prior review. The corporate family rating was downgraded to "B3"; the senior secured rating downgraded to "Ba3"; and the senior unsecured rating was confirmed at "B3." The downgrades did not trigger any obligations under our financing arrangements or other obligations and otherwise have not tangibly impacted our operations or liquidity. The Moody's rating outlook for Dynegy and DHI is negative.

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 contractual arrangements, 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 certain pre-defined events occur, such as financial guarantees.

PPEA Holding was deconsolidated on January 1, 2010 upon adoption of ASU No. 2009-17, which resulted in the deconsolidation of $744 million of debt obligations. Please read Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities for further discussion. As of June 30, 2010, there were no other material changes to our contractual obligations and contingent financial commitments since December 31, 2009.

Please read “Uncertainty of Forward-Looking Statements and Information” for additional factors that could impact our future operating results and financial condition.

RESULTS OF OPERATIONS—DYNEGY INC. and DYNEGY HOLDINGS INC.

Overview. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three- and six- month periods ended June 30, 2010 and 2009. At the end of this section, we have included our outlook for each segment.

We report the results of our power generation business as three separate geographical segments in our unaudited condensed consolidated financial statements. Our unaudited condensed consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization.

Three Months Ended June 30, 2010 and 2009

Summary Financial Information. The following tables provide summary financial data regarding Dynegy’s consolidated and segmented results of operations for the three month periods ended June 30, 2010 and 2009, respectively:

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Dynegy's Results of Operations for the Three Months Ended June 30, 2010

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Revenues	$63	$71	$105	$—	$239
Cost of sales	(110)	(37)	(84)	—	(231)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(55)	(26)	(38)	1	(118)
Depreciation and amortization expense	(63)	(17)	(8)	(2)	(90)
Impairment and other charges	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(28)	(28)
Operating loss	$(165)	$(9)	$(26)	$(29)	$(229)
Other items, net	—	—	—	1	1
Interest expense					(91)
Loss from continuing operations before income taxes					(319)
Income tax benefit					128
Net loss					$(191)

Dynegy's Results of Operations for the Three Months Ended June 30, 2009

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Revenues	$170	$100	$181	$(1)	$450
Cost of sales	(120)	(33)	(110)	—	(263)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(61)	(25)	(50)	(1)	(137)
Depreciation and amortization expense	(57)	(13)	(16)	(3)	(89)
Impairment and other charges	—	—	(387)	—	(387)
General and administrative expense	—	—	—	(45)	(45)
Operating income (loss)	$(68)	$29	$(382)	$(50)	$(471)
Earnings from unconsolidated investments	—	13	—	—	13
Other items, net	—	2	—	2	4
Interest expense					(98)
Loss from continuing operations before income taxes					(552)
Income tax benefit					204
Loss from continuing operations					(348)
Income from discontinued operations, net of taxes.					2

Net loss	(346)
Less: Net loss attributable to the noncontrolling interests	(1)
Net loss attributable to Dynegy Inc.	$(345)

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The following tables provide summary financial data regarding DHI's consolidated and segmented results of operations for the three month periods ended June 30, 2010 and 2009, respectively:

DHI's Results of Operations for the Three Months Ended June 30, 2010

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Revenues	$63	$71	$105	$—	$239
Cost of sales	(110)	(37)	(84)	—	(231)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(55)	(26)	(38)	1	(118)
Depreciation and amortization expense	(63)	(17)	(8)	(2)	(90)
Impairment and other charges	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(28)	(28)
Operating loss	$(165)	$(9)	$(26)	$(29)	$(229)
Other items, net	—	—	—	1	1
Interest expense					(91)
Loss from continuing operations before income taxes					(319)
Income tax benefit					128
Net loss					$(191)

DHI's Results of Operations for the Three Months Ended June 30, 2009

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Revenues	$170	$100	$181	$(1)	$450
Cost of sales	(120)	(33)	(110)	—	(263)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(61)	(25)	(50)	(1)	(137)
Depreciation and amortization expense	(57)	(13)	(16)	(3)	(89)
Impairment and other charges	—	—	(387)	—	(387)
General and administrative expense	—	—	—	(45)	(45)
Operating income (loss)	$(68)	$29	$(382)	$(50)	$(471)
Earnings from unconsolidated investments	—	13	—	—	13
Other items, net	—	2	—	1	3
Interest expense					(98)
Loss from continuing operations before income taxes					(553)
Income tax benefit					205

Loss from continuing operations	(348)
Income from discontinued operations, net of taxes.	12
Net loss	(336)
Less: Net loss attributable to the noncontrolling interests	(1)
Net loss attributable to Dynegy Holdings Inc.	$(335)

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The following table provides summary segmented operating statistics for the three months ended June 30, 2010 and 2009, respectively:

	Three Months Ended June 30, 2010	2009
GEN-MW		
Million Megawatt Hours Generated (1)	5.6	5.9
In Market Availability for Coal Fired Facilities (2)	83 %	92 %
Average Capacity Factor for Combined Cycle Facilities (3)	25 %	28 %
Average Quoted On-Peak Market Power Prices ($/MWh) (4):		
Cinergy (CIN Hub)	$41	$34
Commonwealth Edison (NI Hub)	$40	$32
PJM West	$52	$40
Average Market Spark Spreads ($/MWh) (5):		
PJM West	$19	$12
GEN-WE		
Million Megawatt Hours Generated (6) (7)	0.5	0.8
Average Capacity Factor for Combined Cycle Facilities (3)	17 %	23 %
Average Quoted On-Peak Market Power Prices ($/MWh) (4):		
North Path 15 (NP 15)	$36	$31
Average Market Spark Spreads ($/MWh) (5):		
North Path 15 (NP 15)	$2	$5
GEN-NE		
Million Megawatt Hours Generated	1.6	2.1
In Market Availability for Coal Fired Facilities (2)	96 %	92 %
Average Capacity Factor for Combined Cycle Facilities (3)	38 %	39 %
Average Quoted On-Peak Market Power Prices ($/MWh) (4):		
New York—Zone G	$53	$44
New York—Zone A	$41	$31
Mass Hub	$49	$39
Average Market Spark Spreads ($/MWh) (5):		
New York—Zone A	$7	$2
Mass Hub	$17	$11
Fuel Oil	$(77)	$(53)
Average natural gas price—Henry Hub ($/MMBtu) (8)	$4.30	$3.69

(1) Excludes less than 0.1 million MWh generated by our former Bluegrass power generation facility, which we sold on November 30, 2009 and is reported in discontinued operations, for the three months ended June 30, 2009.

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

(3) Reflects actual production as a percentage of available capacity. Excludes the Arizona power generation facilities which are reported as discontinued operations with respect to the GEN-WE segment for all periods presented. For the 2009 period presented, includes the Tilton, Rocky Road, Riverside and Renaissance power generation facilities with respect to the GEN-MW segment and the Bridgeport power generation facility with

respect to the GEN-NE segment.

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

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

(6) Includes our ownership percentage in the MWh generated by our GEN-WE investment in the Black Mountain power generation facility for the three months ended June 30, 2010 and 2009, respectively.

(7) Excludes less than 0.5 million MWh generated by our Arizona power generation facilities, which we sold on November 30, 2009, and are reported in discontinued operations for the three months ended June 30, 2009.

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

The following table summarizes significant items on a pre-tax basis, with the exception of the tax items, affecting net loss for the period presented:

	Three Months Ended June 30, 2009				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Impairments	$—	$—	$(387)	$—	$(387)
Sandy Creek mark-to-market gains (1)	—	15	—	—	15
Discontinued operations (2)	(17)	18	—	—	1
Total	$(17)	$33	$(387)	$—	$(371)

(1) These mark-to-market gains represent our 50 percent share.
(2) Discontinued operations includes an $18 million impairment for the Bluegrass power generation facility in GEN-MW and a gain of $10 million on the sale of the Heard County power generation facility in GEN-WE.

There were no such items reported for the three months ended June 30, 2010.

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Operating Income (Loss)

Dynegy's and DHI's operating loss was $229 million for the three months ended June 30, 2010, compared to an operating loss of $471 million for the three months ended June 30, 2009.

Our operating loss for the three months ended June 30, 2009 was driven, in large part, by $387 million of asset impairments. Mark-to market losses on forward sales of power and other derivatives associated with our generating assets are included in Revenues in the consolidated statements of operations. Such losses totaled $258 million for the three months ended June 30, 2010, compared to $111 million of mark-to-market losses for the three months ended June 30, 2009. The losses in both periods were impacted by an increase in forward market prices or forward spark spreads during the quarter, as well as the settlement of risk management positions that matured during the quarter.

Power Generation—Midwest Segment. Operating loss for GEN-MW was $165 million for the three months ended June 30, 2010, compared to a loss of $68 million for the three months ended June 30, 2009. Such amounts do not include results from our Bluegrass power generating facility, which has been reclassified as a discontinued operation for all periods presented.

Revenues for the three months ended June 30, 2010 decreased by $107 million compared to the three months ended June 30, 2009, cost of sales decreased by $10 million and operating and maintenance expense decreased by $6 million, resulting in a net decrease of $91 million. The decrease was primarily driven by the following:

- Mark-to-market losses – GEN-MW's results for the three months ended June 30, 2010 included mark-to-market losses of $183 million related to forward sales and other derivative contracts, compared to $129 million of mark-to-market losses for the three months ended June 30, 2009. Of the $183 million in 2010 mark-to-market losses, $108 million related to positions that settled or will settle in 2010, and the remaining $75 million related to positions that will settle in 2011 and beyond;

- Energy sales – GEN-MW's results from energy sales, including both physical and financial transactions, decreased from $150 million for the three months ended June 30, 2009 to $109 million for the three months ended June 30, 2010. The contribution from physical transactions was higher primarily as a result of higher power prices at our coal-fired facilities and improved spark spreads at our combined cycle facilities, partially offset by more unplanned outages. However, these increases were more than offset by a reduced contribution from financial transactions; and

- Decreased tolling/capacity revenues of $5 million – Tolling/capacity revenues decreased $9 million as a result of the sale of assets in the fourth quarter 2009 and $6 million primarily as a result of terminating our Kendall tolling contract. These decreases were partially offset by higher capacity revenues of $10 million due to additional capacity we were able to sell as a result of the termination of that toll.

These items were partly offset by the following:

- Decreased operating and maintenance expenses – operating and maintenance expenses decreased from $61 million for the three months ended June 30, 2009 to $55 million for the three months ended June 30, 2010, primarily as a result of the sale of certain Midwest assets to LS Power in the fourth quarter 2009, as well as lower planned outage expenses.

Depreciation expense increased from $57 million for the second quarter 2009 to $63 million for the second quarter 2010. The impact of additional Midwest Consent Decree expenditures and early retirement of Wood River units 1-3 and Havana units 1-5 was largely offset by the sale of assets in 2009.

Power Generation—West Segment. Operating loss for GEN-WE was $9 million for three months ended June 30, 2010, compared to income of $29 million for the three months ended June 30, 2009. Such amounts do not include results from our Arizona and Heard County power generating facilities, which have been reclassified as discontinued operations for all periods presented.

Revenues for the three months ended June 30, 2010 decreased by $29 million compared to the three months ended June 30, 2009, cost of sales increased by $4 million and operating and maintenance expense increased by $1 million, resulting in a net decrease of $34 million. The decrease was primarily driven by the following:

- Mark-to-market losses – GEN-WE's results for the three months ended June 30, 2010 included mark-to-market losses of $27 million related to forward sales and other derivative contracts, compared to $10 million of mark-to-market gains for the three months ended June 30, 2009. Of the $27 million in 2010 mark-to-market losses, $13 million related to positions that settled or will settle in 2010, and the remaining $14 million related to positions that will settle in 2011 and beyond.

This item was partially offset by the following:

- Energy sales – GEN-WE's results from energy sales, including both physical and financial transactions, increased from $19 million for the three months ended June 30, 2009 to $25 million for the three months ended June 30, 2010. The contribution from physical transactions was lower primarily as a result of reduced spark spreads; however, this decrease was more than offset by increased contribution from financial transactions.

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Depreciation expense increased from $13 million for the second quarter 2009 to $17 million for the second quarter 2010 as a result of capital projects placed into service.

Power Generation—Northeast Segment. Operating loss for GEN-NE was $26 million for the three months ended June 30, 2010, compared to a loss of $382 million for the three months ended June 30, 2009. Operating losses for the three months ended June 30, 2009 included a $179 million impairment of our Bridgeport power generating facility and related assets, and a $208 million impairment of our Roseton and Danskammer power generation facilities reflected in Impairment and other charges in our unaudited condensed consolidated statements of operations for the three months ended June 30, 2009.

Revenues for the three months ended June 30, 2010 decreased by $76 million compared to the three months ended June 30, 2009, cost of sales decreased by $26 million and operating and maintenance expense decreased by $12 million, resulting in a net decrease of $38 million. The decrease was primarily driven by the following:

- Mark-to-market losses – GEN-NE’s results for the three months ended June 30, 2010 included mark-to-market losses of $48 million related to forward sales and other derivative contracts, compared to gains of $8 million for the three months ended June 30, 2009. Of the $48 million in 2010 mark-to-market losses, $21 million related to positions that settled or will settle in 2010, and the remaining $27 million related to positions that will settle in 2011 and beyond.

This was partly offset by:

- Decreased operating and maintenance expenses – Operating and maintenance expenses decreased from $50 million for the three months ended June 30, 2009 to $38 million for the three months ended June 30, 2010 as a result of the sale of our Bridgeport facility in the fourth quarter 2009 and lower maintenance expenses;

    - A coal inventory write-down of approximately $8 million recorded during the second quarter 2009; and

- Energy sales – GEN-NE’s results from energy sales, including both physical and financial transactions, increased from $17 million for the three months ended June 30, 2009 to $23 million for the three months ended June 30, 2010. The contribution from physical transactions increased primarily as a result of improved spark spreads and higher prices resulting from warmer weather, partially offset by the sale of our Bridgeport facility in the fourth quarter 2009. The contribution from financial transactions also increased.

Depreciation expense decreased from $16 million for the second quarter 2009 to $8 million for the second quarter 2010, primarily due to the sale of the Bridgeport power generating facility and the impairments of our Roseton and Danskammer power generation facilities in the second quarter 2009.

Other. Dynegy’s and DHI’s other operating loss for the three months ended June 30, 2010 was $29 million, compared to an operating loss of $50 million for the three months ended June 30, 2009. Operating losses in both periods were comprised primarily of general and administrative expenses.

Consolidated general and administrative expenses were $28 million and $45 million for the three months ended June 30, 2010 and 2009, respectively. General and administrative expenses for the three months ending June 30, 2010 are lower when compared to the three months ended June 30, 2009 due to lower stock-based compensation expense resulting from changes in fair value, cost reduction program savings, and lower professional and legal expenses.

Earnings from Unconsolidated Investments

Dynegy's and DHI's earnings from unconsolidated investments were $13 million for the three months ended June 30, 2009, related to the GEN-WE investment in Sandy Creek, which was sold in the fourth quarter 2009. The $13 million consisted of mark-to-market gains of $15 million primarily related to interest rate swap contracts partly offset by financing costs of $2 million.

Other Items, Net

Dynegy's and DHI's other items, net, totaled $1 million of income for the three months ended June 30, 2010, compared to $4 million and $3 million, respectively, of income for the three months ended June 30, 2009. The decrease is primarily associated with lower interest income due to lower cash and restricted cash balances in 2010 and insurance proceeds received in 2009.

Interest Expense

Dynegy's and DHI's interest expense totaled $91 million for the three months ended June 30, 2010, compared to $98 million for the three months ended June 30, 2009. The decrease was primarily attributable to lower outstanding debt due to the December 2009 repurchase of $833 million in aggregate principal amount of our senior unsecured notes, as well as the deconsolidation of PPEA Holding. These decreases were partly offset by the December 2009 issuance of $235 million of senior unsecured notes in connection with the LS Power Transactions, and higher applicable margin on our variable-rate debt resulting from an amendment in August 2009 to the Credit Facility.

Income Tax Benefit

Dynegy reported an income tax benefit from continuing operations of $128 million for the three months ended June 30, 2010, compared to an income tax benefit from continuing operations of $204 million for the three months ended June 30, 2009. The 2010 effective tax rate was 40 percent, compared to 37 percent in 2009.

DHI reported an income tax benefit from continuing operations of $128 million for the three months ended June 30, 2010, compared to an income tax benefit of $205 million from continuing operations for the three months ended June 30, 2009. The 2010 effective tax rate was 40 percent, compared to 37 percent in 2009.

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For the three month period ended June 30, 2010, the difference between the effective rate of 40 percent for Dynegy and DHI, respectively, and the statutory rate of 35 percent resulted primarily from the impact of state taxes. As a result of the LS Power Transactions, we revised our assumptions around the ability to utilize certain state deferred tax assets, and therefore Dynegy and DHI recorded valuation allowances resulting in additional state tax expense of $10 million and $7 million, respectively for the three months ended June 30, 2009.

Discontinued Operations

Income From Discontinued Operations Before Taxes

During the three months ended June 30, 2009, Dynegy's and DHI's pre-tax income from discontinued operations was $1 million. Our GEN-MW segment included an $18 million impairment charge offset by $1 million of income related to the operations of our Bluegrass power generation facility. Our GEN-WE segment included $10 million of pre-tax gain on the sale of the Heard County power generation facility and $8 million from the operation of the Heard County and Arizona power generation facilities.

Income Tax Benefit From Discontinued Operations

Dynegy recorded an income tax benefit from discontinued operations of $1 million during the three months ended June 30, 2009 which reflects an effective rate of 100 percent. DHI recorded an income tax benefit from discontinued operations of $11 million during the three months ended June 30, 2009. The detailed methodology of allocating income taxes between continuing and discontinued operations often results in an effective rate for discontinued operations significantly different from the statutory rate of 35 percent.

Six Months Ended June 30, 2010 and 2009

Summary Financial Information. The following tables provide summary financial data regarding Dynegy's consolidated and segmented results of operations for the six months ended June 30, 2010 and 2009, respectively:

Dynegy's Results of Operations for the Six Months Ended June 30, 2010

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Revenues	$549	$214	$334	$—	$1,097
Cost of sales	(237)	(96)	(206)	—	(539)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(104)	(49)	(77)	(1)	(231)
Depreciation and amortization expense	(113)	(33)	(16)	(3)	(165)
Impairment and other charges	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(59)	(59)
Operating income (loss)	$95	$36	$34	$(63)	$102
Losses from unconsolidated investments	(34)	—	—	—	(34)
Other items, net	—	—	1	1	2
Interest expense					(180)
Loss from continuing operations before income taxes					(110)

Income tax benefit	63
Loss from continuing operations	(47)
Income from discontinued operations, net of taxes	1
Net loss	$(46)

Dynegy's Results of Operations for the Six Months Ended June 30, 2009

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Revenues	$694	$183	$478	$(1)	$1,354
Cost of sales	(260)	(85)	(296)	—	(641)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(112)	(51)	(92)	3	(252)
Depreciation and amortization expense	(108)	(30)	(31)	(6)	(175)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	—	—	(387)	—	(387)
General and administrative expense	—	—	—	(83)	(83)
Operating income (loss)	$138	$(243)	$(425)	$(87)	$(617)
Earnings from unconsolidated investments	—	20	—	1	21
Other items, net	2	2	—	4	8
Interest expense					(196)
Loss from continuing operations before income taxes					(784)
Income tax benefit					113
Loss from continuing operations					(671)
Loss from discontinued operations, net of taxes.					(12)
Net loss					(683)
Less: Net loss attributable to the noncontrolling interests					(3)
Net loss attributable to Dynegy Inc.					$(680)

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The following tables provide summary financial data regarding DHI's consolidated and segmented results of operations for the six month periods ended June 30, 2010 and 2009, respectively:

DHI's Results of Operations for the Six Months Ended June 30, 2010

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Revenues	$549	$214	$334	$—	$1,097
Cost of sales	(237)	(96)	(206)	—	(539)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(104)	(49)	(77)	(1)	(231)
Depreciation and amortization expense	(113)	(33)	(16)	(3)	(165)
Impairment and other charges	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(59)	(59)
Operating income (loss)	$95	$36	$34	$(63)	$102
Losses from unconsolidated investments	(34)	—	—	—	(34)
Other items, net	—	—	1	1	2
Interest expense					(180)
Loss from continuing operations before income taxes					(110)
Income tax benefit					56
Loss from continuing operations					(54)
Income from discontinued operations, net of taxes					1
Net loss					$(53)

DHI's Results of Operations for the Six Months Ended June 30, 2009

	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
Revenues	$694	$183	$478	$(1)	$1,354
Cost of sales	(260)	(85)	(296)	—	(641)
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(112)	(51)	(92)	1	(254)
Depreciation and amortization expense	(108)	(30)	(31)	(6)	(175)
Goodwill impairments	(76)	(260)	(97)	—	(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	—	—	(387)	—	(387)
General and administrative expense	—	—	—	(83)	(83)
Operating income (loss)	$138	$(243)	$(425)	$(89)	$(619)
Earnings from unconsolidated investments	—	20	—	—	20

Other items, net	2	2	—	3	7
Interest expense					(196)
Loss from continuing operations before income taxes					(788)
Income tax benefit					117
Loss from continuing operations					(671)
Loss from discontinued operations, net of taxes.					(2)
Net loss					(673)
Less: Net loss attributable to the noncontrolling interests					(3)
Net loss attributable to Dynegy Holdings Inc.					$(670)

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The following table provides summary segmented operating statistics for the six months ended June 30, 2010 and 2009, respectively:

	Six Months Ended June 30,					
		2010			2009	
GEN-MW						
Million Megawatt Hours Generated (1)		12.0			12.5	
In Market Availability for Coal Fired Facilities (2)		89	%		88	%
Average Capacity Factor for Combined Cycle Facilities (3)		20	%		29	%
Average Quoted On-Peak Market Power Prices ($/MWh) (4)						
Cinergy (CIN Hub)	$	42		$	37	
Commonwealth Edison (NI Hub)	$	41		$	36	
PJM West	$	52		$	48	
Average Market Spark Spreads ($/MWh) (5)						
PJM West	$	14		$	12	
GEN-WE						
Million Megawatt Hours Generated (6) (7)		1.9			2.3	
Average Capacity Factor for Combined Cycle Facilities (3)		38	%		38	%
Average Quoted On-Peak Market Power Prices ($/MWh) (4)						
North Path 15 (NP 15)	$	41		$	36	
Average Market Spark Spreads ($/MWh) (5)						
North Path 15 (NP 15)	$	5		$	5	
GEN-NE						
Million Megawatt Hours Generated		3.1			5.3	
In Market Availability for Coal Fired Facilities (2)		94	%		95	%
Average Capacity Factor for Combined Cycle Facilities (3)		33	%		44	%
Average Quoted On-Peak Market Power Prices ($/MWh) (4)						
New York—Zone G	$	55		$	53	
New York—Zone A	$	40		$	39	
Mass Hub	$	52		$	49	
Average Market Spark Spreads ($/MWh) (5)						
New York—Zone A	$	3		$	6	
Mass Hub	$	13		$	11	
Fuel Oil	$	(74	)	$	(31	)
Average natural gas price—Henry Hub ($/MMBtu) (8)	$	4.73		$	4.13	

(1) Excludes approximately less than 0.1 million MWh generated by our Bluegrass power generation facility, which we sold on November 30, 2009 and is reported in discontinued operations, for the six months ended June 30, 2009.

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

(3) Reflects actual production as a percentage of available capacity. Excludes Arizona power generation facilities which are reported as discontinued operations with respect to the GEN-WE segment. For the 2009 period presented, includes the Tilton, Rocky Road, Riverside and Renaissance power generation facilities with respect to the GEN-MW segment and the Bridgeport power generation facility with respect to the GEN-NE segment.

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

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

(6) Includes our ownership percentage in the MWh generated by our GEN-WE investment in the Black Mountain power generation facility for the six months ended June 30, 2010 and 2009, respectively.

(7) Excludes less than 0.1 million MWh generated by the Heard County power generation facility, which we sold in April 2009 and is reported in discontinued operations, for the six months ended June, 30, 2009. Excludes approximately 0.5 million MWh generated by our Arizona power generation facilities, which we sold on November 30, 2009 and are reported in discontinued operations, for the six months ended June 30, 2009.

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

The following tables summarize significant items on a pre-tax basis, with the exception of the tax items, affecting net loss for the period presented:

	Six Months Ended June 30, 2010				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
PPEA Holding impairment	$(37)	$—	$—	$—	$(37)
Taxes	—	—	—	11	11
Total—DHI	(37)	—	—	11	(26)
Taxes	—	—	—	5	5
Total—Dynegy	$(37)	$—	$—	$16	$(21)

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	Six Months Ended June 30, 2009				
	Power Generation				
	GEN-MW	GEN-WE	GEN-NE	Other	Total
			(in millions)		
Impairments	$(76)	$(260)	$(484)	$—	$(820)
Sandy Creek mark-to-market gains (1)	—	25	—	—	25
Discontinued operations (2)	(23)	4	—	—	(19)
Taxes	—	—	—	(15)	(15)
Total—DHI	(99)	(231)	(484)	(15)	(829)
Taxes	—	—	—	(6)	(6)
Total—Dynegy	$(99)	$(231)	$(484)	$(21)	$(835)

(1) These mark-to-market gains represent our 50 percent share.
(2) Discontinued operations includes a $23 million impairment of the Bluegrass power generation facility in GEN-MW and a gain of $10 million on the sale of the Heard County power generation facility in GEN-WE.

Operating Income (Loss)

Operating income for Dynegy was $102 million for the six months ended June 30, 2010, compared to an operating loss of $617 million for the six months ended June 30, 2009. Operating income for DHI was $102 million for the six months ended June 30, 2010, compared to an operating loss of $619 million for the six months ended June 30, 2009.

Our operating loss for the six months ended June 30, 2009 was driven, in large part, by a $433 million impairment of goodwill and by $387 million of asset impairments. Mark-to-market losses on forward sales of power associated with our generating assets are included in Revenues in the unaudited condensed consolidated statements of operations. Such losses totaled $5 million for the six months ended June 30, 2010 compared to $58 million of mark-to-market gains for the six months ended June 30, 2009. The losses in 2010 reflect a loss from the impact of the settlement of risk management positions that matured during the period, largely offset by an increase in the value of positions related to a decrease in forward market prices or spark spreads during the period. The gains in 2009 were the result of a decrease in forward market prices or forward spark spreads during the six month period ended June 30, 2009, partly offset by the impact of the settlement of risk management positions that matured during the period.

Power Generation—Midwest Segment. Operating income for GEN-MW was $95 million for the six months ended June 30, 2010, compared to $138 million for the six months ended June 30, 2009. Such amounts do not include results from our Bluegrass power generating facility, which has been reclassified as a discontinued operation for all periods presented. Operating income for the six months ended June 30, 2009 included a pre-tax charge of approximately $76 million for the impairment of goodwill, reflected in Goodwill impairments in our unaudited condensed consolidated statements of operations.

Revenues for the six months ended June 30, 2010 decreased by $145 million compared to the six months ended June 30, 2009, cost of sales decreased by $23 million and operating and maintenance expense decreased by $8 million, resulting in a net decrease of $114 million. The decrease was primarily driven by the following:

- Energy sales – GEN-MW's results from energy sales, including both physical and financial transactions, decreased from $334 million for the six months ended June 30, 2009 to $241 million for the six months ended June 30, 2010. The contribution from physical transactions increased primarily as a result of higher power prices at our coal fired facilities and improved spark spreads at our combined cycle facilities, partially offset by more unplanned outages; however, these increases were more than offset by reduced contribution from financial transactions; and

- Mark-to-market losses – GEN-MW's results for the six months ended June 30, 2010 included mark-to-market losses of $4 million related to forward sales and other derivative contracts, compared to $40 million of mark-to-market gains for the six months ended June 30, 2009. Of the $4 million in 2010 mark-to-market losses, $34 million of losses related to positions that settled or will settle in 2010, partly offset by $30 million of gains related to positions that will settle in 2011 and beyond.

These items were partly offset by the following:

- Increased tolling/capacity revenues of $17 million – Tolling revenues increased by $12 million primarily as a result of a termination fee received for exiting our Kendall tolling contract early. Capacity revenues also increased by $22 million due to previously contracted PJM capacity at higher prices than the prior year and additional capacity revenue from previously tolled power generation facilities. These increases were partially offset by a $17 million reduction in tolling/capacity revenues as a result of asset sales; and

- Decreased operating and maintenance expenses – operating and maintenance expenses decreased from $112 million for the six months ended June 30, 2009 to $104 million for the six months ended June 30, 2010, primarily as a result of the sale of certain Midwest assets to LS Power in the fourth quarter 2009 as well as lower planned outage expenses.

Depreciation expense increased from $108 million for the six months ended June 30, 2009 to $113 million for the six months ended June 30, 2010. The impact of additional Midwest Consent Decree expenditures and early retirement of Wood River units 1-3 and Havana units 1-5 was largely offset by the sale of assets in 2009.

Power Generation—West Segment. Operating income for GEN-WE was $36 million for six months ended June 30, 2010, compared to operating loss of $243 million for the six months ended June 30, 2009. Such amounts do not include results from our Arizona and Heard County power generating facilities, which have been classified as discontinued operations for all periods presented. Operating loss for the six months ended June 30, 2009 included a pre-tax charge of approximately $260 million for the impairment of goodwill, reflected in Goodwill impairments in our unaudited condensed consolidated statements of operations.

Revenues for the six months ended June 30, 2010 increased by $31 million compared to the six months ended June 30, 2009, cost of sales increased by $11 million and operating and maintenance expense decreased by $2 million, resulting in a net increase of $22 million. The increase was primarily driven by the following:

- Reduced mark-to-market losses – GEN-WE's results for the six months ended June 30, 2010 included mark-to-market losses of $4 million related to forward sales and other derivative contracts, compared to $19 million of mark-to-market losses for the six months ended June 30, 2009. Of the $4 million in 2010 mark-to-market losses, $9 million in gains related to positions that settled or will settle in 2010, and was more than offset by $13 million in losses related to positions that will settle in 2011 and beyond; and

- Energy sales – GEN-WE's results from energy sales, including both physical and financial transactions, increased from $44 million for the six months ended June 30, 2009 to $52 million for the six months ended June 30, 2010. The contribution from physical transactions decreased primarily as a result of reduced spark spreads; however, this decrease was more than offset by increased contribution from financial transactions.

Depreciation expense increased from $30 million for the six months ended June 30, 2009 to $33 million for the six months ended June 30, 2010.

Power Generation—Northeast Segment. Operating income for GEN-NE was $34 million for the six months ended June 30, 2010, compared to operating loss of $425 million for the six months ended June 30, 2009. Operating loss for the six months ended June 30, 2009 included a pre-tax charge of approximately $97 million for the impairment of goodwill, reflected in Goodwill impairment in our unaudited condensed consolidated statements of operations.

In addition, we recorded a $179 million impairment of our Bridgeport power generating facility and related assets, and a $208 million impairment of our Roseton and Danskammer power generation facilities and related assets reflected in Impairment and other charges in our unaudited condensed consolidated statements of operations, during the six months ended June 30, 2009.

Revenues for the six months ended June 30, 2010 decreased by $144 million compared to the six months ended June 30, 2009, cost of sales decreased by $90 million and operating and maintenance expense decreased by $15 million, resulting in a net decrease of $39 million. The decrease was primarily driven by the following:

- Reduced mark-to-market gains – GEN-NE's results for the six months ended June 30, 2010 included mark-to-market gains of $3 million related to forward sales and other derivative contracts, compared to gains of $37 million for the six months ended June 30, 2009. Of the $3 million in 2010 mark-to-market gains, $6 million in gains related to positions that settled or will settle in 2010, and offset by $3 million in losses related to positions that will settle in 2011 and beyond;

- Energy sales – GEN-NE's results from energy sales, including both physical and financial transactions, decreased from $49 million for the six months ended June 30, 2009 to $38 million for the six months ended June 30, 2010. The contribution from physical tranactions decreased primarily as a result of weaker winter spark spreads and the sale of our Bridgeport facility in the fourth quarter 2009, partially offset by improved spark spreads and higher prices resulting from warmer weather in the second quarter as well as increased contribution from financial transactions;

- Emissions sales – sales of emissions decreased by $10 million due to lower sale volumes and market prices of emissions credits in 2010; and

-

Decreased capacity revenues of $6 million – Capacity revenues decreased primarily due to an $11 million reduction in capacity revenue from the Bridgeport facility that was sold to LS Power in the fourth quarter 2009. This decrease was partially offset by increased capacity revenues at our other facilities due to slightly higher prices.

These items were partly offset by:

- Decreased operating and maintenance expenses – Operating and maintenance expenses decreased from $92 million for the six months ended June 30, 2009 to $77 million for the six months ended June 30, 2010, primarily as a result of the sale of our Bridgeport facility in the fourth quarter 2009 and lower maintenance expenses; and

  - Coal inventory write-down of approximately $10 million recorded during the six months ended 2009.

Depreciation expense decreased from $31 million for the six months ended June 30, 2009 to $16 million for the six months ended June 30, 2010, primarily due to the sale of the Bridgeport power generating facility and the impairments of our Roseton and Danskammer power generation facilities which were recorded beginning in the second quarter 2009.

Other. Dynegy's other operating loss for the six months ended June 30, 2010 was $63 million, compared to an other operating loss of $87 million for the six months ended June 30, 2009. DHI's other operating loss for the six months ended June 30, 2010 was $63 million, compared to an other operating loss of $89 million for the six months ended June 30, 2009. Operating losses in both periods were comprised primarily of general and administrative expenses.

Consolidated general and administrative expenses decreased from $83 million from the six months ended June 30, 2009 to $59 million for the six months ended June 30, 2010. General and administrative expenses for the six months ending June 30, 2010 are lower when compared to the six months ended June 30, 2009 due to cost reduction program savings, lower stock-based compensation expense resulting from changes in fair value, and lower professional and legal expenses.

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Earnings (Losses) from Unconsolidated Investments

Losses from unconsolidated investments were $34 million for the six months ended June 30, 2010 related to the GEN-MW investment in PPEA Holding. The losses consisted of an impairment charge of approximately $37 million partially offset by $3 million in equity earnings primarily related to mark-to-market gains on interest rate swaps offset by financing expenses. Due to the uncertainty regarding PPEA's financing structure, our investment in PPEA Holding was fully impaired at March 31, 2010. Please see Note 8—Variable Interest Entities—PPEA Holding Company LLC for further discussion.

Earnings from unconsolidated investments were $21 million and $20 million for Dynegy and DHI, respectively, for the six months ended June 30, 2009. Earnings of $20 million related to the GEN-WE investment in Sandy Creek. The $20 million consisted of $25 million in mark-to-market gains primarily related to interest rate swap contracts offset by $5 million of financing costs. Dynegy's earnings also included $1 million of earnings related to Dynegy's former investment in DLS Power Development, included in Other.

Other Items, Net

Dynegy's and DHI's other items, net, totaled $2 million of income for the six months ended June 30, 2010, compared to $8 million and $7 million, respectively, of income for the six months ended June 30, 2009. The decrease is primarily associated with lower interest income due to lower cash and restricted cash balances in 2010.

Interest Expense

Dynegy's and DHI's interest expense totaled $180 million for the six months ended June 30, 2010, compared to $196 million for the six months ended June 30, 2009. The decrease was primarily attributable to lower outstanding debt due to the December 2009 repurchase of $833 million in aggregate principal amount of our senior unsecured notes, as well as the deconsolidation of PPEA Holding. These decreases were partly offset by the December 2009 issuance of $235 million of senior unsecured notes in connection with the LS Power Transactions, and higher applicable margin on our variable-rate debt resulting from an amendment in August 2009 to the Credit Facility.

Income Tax Benefit

Dynegy reported an income tax benefit from continuing operations of $63 million for the six months ended June 30, 2010, compared to an income tax benefit from continuing operations of $113 million for the six months ended June 30, 2009. The 2010 effective tax rate was 57 percent, compared to 14 percent in 2009.

DHI reported an income tax benefit from continuing operations of $56 million for the six months ended June 30, 2010, compared to an income tax benefit of $117 million from continuing operations for the six months ended June 30, 2009. The 2010 effective tax rate was 51 percent, compared to 15 percent in 2009.

The primary difference between the effective rates of 57 and 51 percent for Dynegy and DHI, respectively, for the six months ended June 30, 2010 and the statutory rate of 35 percent resulted primarily from the benefit of $18 million and $12 million for Dynegy and DHI, respectively, related to the release of reserves for uncertain tax positions, partly offset by the impact of state taxes. For the period ended June 30, 2009, the difference resulted from the effect of the nondeductible goodwill impairment charge. Additionally, for the six months ended June 30, 2009, Dynegy and DHI recorded $21 million and $15 million, respectively, of income tax expense related to a change in California state tax law. As a result of the LS Power Transactions, we revised our assumptions around the ability to utilize certain state deferred tax assets, and therefore Dynegy and DHI recorded valuation allowances resulting in additional state tax expense of $10 million and $7 million, respectively for the six months ended June 30, 2009.

Discontinued Operations

Income (Loss) From Discontinued Operations Before Taxes

For the six months ended June 30, 2010, our pre-tax income from discontinued operations was $1 million. For the six months ended June 30, 2009, Dynegy and DHI's pre-tax loss from discontinued operations was $19 million. Our GEN-MW segment included a $23 million impairment charge related to our Bluegrass power generation facility. Our GEN-WE segment included $10 million of pre-tax gain on sale of the Heard County power generation facility and a pre-tax loss of $6 million from the operation of the Heard County and Arizona power generation facilities.

Income Tax Benefit From Discontinued Operations

Dynegy recorded an income tax benefit from discontinued operations of zero during the six months ended June 30, 2010, compared to an income tax benefit from discontinued operations of $7 million during the six months ended June 30, 2009, these amounts reflect effective rates of zero and 37 percent, respectively. DHI recorded an income tax benefit from discontinued operations of zero during the six months ended June 30, 2010, compared to an income tax benefit of $17 million during the six months ended June 30, 2009, these amounts reflect effective rates of zero and 89 percent, respectively. The detailed methodology of allocating income taxes between continuing and discontinued operations often results in an effective rate for discontinued operations significantly different from the statutory rate of 35 percent.

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Outlook

Our power generation portfolio consists of approximately 12,100 MW of generating capacity that is diversified by fuel source (i.e., coal, natural gas and fuel oil) and dispatch type (i.e., baseload, intermediate and peaking facilities).

We expect that our future financial results will continue to be sensitive to fuel and commodity prices, market structure and prices for electric energy, capacity and ancillary services, including pricing at our plant locations relative to pricing at their respective trading hubs, transportation and transmission logistics, weather conditions and IMA. Further, as described in our Form 10-K, there is a trend toward greater environmental regulation of all aspects of our business. As this trend continues, it is likely that we will experience additional costs and limitations. Please read Item 1. Business—Environmental Matters in our Form 10-K as well as environmental matters discussed below.

Our commercial team seeks to actively manage commodity price risk associated with our unsold power production by trading in forward markets. We also participate in various regional auctions and bilateral opportunities. Our regional commercial strategies are particularly driven by the types of power generation facilities that we have within a given region and the operating characteristics of those facilities. We have volumetrically hedged nearly 100 percent of our expected generation volumes for 2010 and 2011. Based on specific market conditions, at any point in time we may enter into transactions that will increase or decrease the portion of our expected output that has been contracted. Even though we have largely contracted our expected output through 2011, our future operating cash flows may vary based on a number of other factors, including the value of capacity and ancillary services, the operational performance of our generating facilities, the price differential between the locations where we deliver generated power and the liquid market hub, legal, environmental, and regulatory requirements, and other factors.

Our forward hedging strategy for our coal assets has helped mitigate some of the effect of the compressed spark spreads for 2011. The volatility in fuel oil and natural gas commodity pricing and changes to spark spreads may provide us opportunities to capture short-term market value through strategic purchases of these commodities and sales of power in the spot or forward markets. To the extent that we choose not to enter into forward transactions, the gross margin from our assets is highly sensitive to price movements in the coal, natural gas, fuel oil, electric energy and capacity markets.

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

GEN-MW. Our Midwest Consent Decree requires substantial emission reductions from our Illinois coal-fired power plants and the completion of several supplemental environmental projects in the Midwest. We have achieved all emission reductions scheduled to date under the Midwest Consent Decree and are in the process of installing additional emission control equipment to meet future Midwest Consent Decree emission limits. We expect our costs associated with the remaining Midwest Consent Decree projects, which we have planned to incur through 2013, to be approximately $315 million. This estimate includes a number of assumptions about uncertainties beyond our control, such as costs associated with labor and materials. If the costs of these capital expenditures become great enough to render the operation of the affected power generation facility or facilities uneconomical, we could, at our option, cease to operate the power generation facility or facilities and forego these capital expenditures without incurring any further obligations under the Midwest Consent Decree.

Our Midwest coal requirements are approximately 100 percent contracted for 2010 and 90 percent contracted in 2011 and 95 percent contracted in 2012. All forecast coal requirements are priced through 2010, 51 percent are priced through 2011 and 25 percent are priced through 2012. Committed volumes that are currently unpriced are subject to a price collar structure. Our Midwest coal transportation requirements are 100 percent contracted and priced through 2013, except for coal transportation for our Vermilion power generation facility, which is priced through 2010. We continue to explore various alternative contractual commitments and financial options, as well as facility modifications, to ensure stable and competitive fuel supplies and to mitigate further supply risks for near- and long-term coal supplies. Our Midwest expected generation volumes are fully hedged through 2011 and approximately 15 percent hedged for 2012.

Increased demand in MISO has resulted in a slight improvement in day-ahead pricing, which in turn has reduced the amount of cycling in our baseload facilities and reduced MISO system minimum generation events. However, ongoing ISO transmission upgrades along with scheduled and unscheduled maintenance projects continue to have the potential to negatively impact both pricing and facility output for extended periods of time within our MISO fleet. We seek to hedge some of these exposures through active participation in markets for financial transmission rights and participation in transmission resource planning and upgrade initiatives.

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Recent moves by certain MISO market participants expressing their intentions to exit the MISO could mitigate earlier membership increases and impact system reserve margins favorably in the future. The impacts to MISO capacity market-clearing practices and the resulting prices are unclear at this time as the ISO continues to consult with market stakeholders regarding optimal capacity auction mechanics and product offerings. In addition, competing initiatives of increased market participation by demand response resources offset by potential retirement of marginal MISO coal capacity due to expected environmental mandates could also affect MISO capacity and energy markets in the future.

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

Our South Bay and Oakland power generation facilities are operating under RMR agreements with the CAISO which expire on December 31, 2010, unless the CAISO extends the RMR designation through 2011. The South Bay power generation facility will permanently cease operation upon the termination of RMR designation by the CAISO as per the terms of the lease with the Port of San Diego. Please read Environmental and Regulatory Matters—South Bay NPDES Permit below for further discussion.

Upon retirement of the South Bay power generation facility, we have a contractual obligation to demolish the plant and remediate specific parcels of the property. The costs associated with plant closure have been included in the 2010 RMR rate filing, as have any remaining, unfunded expected demolition and remediation costs. Negotiation of the 2010 RMR rates is ongoing.

GEN-NE. Our physical coal supply and delivery requirements for our Danskammer coal-fired asset are fully contracted and priced through 2010. Our coal supply requirements for 2011 are financially hedged to complement our volumetric power hedges. We have sourced most of our coal from South America, but have access to and are exploring multiple options for our 2011 supply and delivery requirements. We continue to explore various alternative contractual commitments and financial options, as well as facility modifications, to ensure stable and competitive fuel supplies and to mitigate further supply risks for near- and long-term coal supplies. While natural gas prices have increased slightly in recent months, they are expected to continue to compress dark spreads and likely to alter the dispatch stack favoring natural gas-fired assets over coal-fired assets during shoulder months in much of the Northeast for the near term. Approximately 25 percent of our capacity sales in the NYISO are contracted through 2014. We have attempted to maximize revenue opportunities for the balance of our portfolio through active participation in the NYISO capacity auctions and through bilateral transactions.

The ISO-NE restructured its capacity market and has transitioned to a forward capacity market structure in 2010. The delivery of capacity under the forward capacity market became fully effective on June 1, 2010. Capacity auctions for the 2010-2011, 2011-2012 and 2012-2013 market periods were held in 2008 and 2009 and resulted in capacity clearing prices of $4.50 kW-month, $3.60 kW-month and $2.95 kW-month respectively. These capacity clearing prices represent the floor price, and the actual rate paid to Casco Bay has been affected by pro-rationing due to oversupply conditions. Efforts to implement prospective improvements in the forward capacity market design are currently underway in active proceedings at FERC and in discussions by the ISO and its stakeholders.

Environmental and Regulatory Matters

Federal Regulation of Greenhouse Gases. Please read Item 1 Business – Environmental Matters—Climate Change—Federal Regulation of Greenhouse Gases in our Form 10-K.

The EPA proposed to "phase in" new GHG emissions applicability thresholds for its PSD permit program and for the operating permit program under Title V of the CAA. PSD permits for new major sources of GHG, and for GHG sources that undergo major modification on or after January 2, 2011, will be required to implement BACT for the control of GHG emissions.

New York Regional Haze Rule. In July 1999, the EPA published its final Regional Haze Rule which requires states to submit regional haze implementation plans to the EPA detailing their plans to reduce emissions of visibility–impairing pollutants (NOx, SO2 and particulates) that affect visibility in downwind Federal Class I Areas (i.e. parks and wilderness) with a goal to restore natural visibility conditions in these areas by 2064. The State of New York has been identified as having certain BART eligible facilities that contribute to regional haze in Class I Areas in other states. On May 1, 2010, the New York State BART Rule became effective, which requires our Danskammer and Roseton power generation facilities to: (i) undertake a comprehensive, unit specific modeling analysis for their BART eligible units to determine such units' impact on visibility and (ii) develop actions necessary to reduce impacts on visibility in order to meet federal standards. Results of these analyses are required to be submitted to NYSDEC by October 1, 2010. Any required installation of approved emission control equipment and/or implementation of other emission reduction methods must occur no later than January 1, 2014. We are currently working to complete the required analyses and to determine the potential impact, if any, on our Danskammer and Roseton facilities.

California Water Intake Policy. On March 22, 2010, the California State Water Board issued its proposed draft final Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (the "Policy"). The California Water Board adopted the Policy at its meeting on May 4, 2010 with several amendments making it more stringent than the proposed draft Policy. The approved Policy will require that existing power plants: (i) reduce their water intake flow rate to a level commensurate with that which can be achieved by a closed cycle cooling system; or (ii) if it is not feasible to reduce the water intake flow rate to this level, reduce impingement mortality and entrainment to a level comparable to that achieved by such a reduced water intake flow rate using operational or structural controls, or both. Compliance with the Policy will be required at our South Bay power generation facility by December 31, 2011, at our Morro Bay power generation facility by December 31, 2015 and at our Moss Landing power generation facility by December 31, 2017. While we are continuing to review the potential impact of the Policy on our affected power generation facilities, it may not be possible to meet the requirements of the Policy without installing closed cycle cooling systems. The Policy is subject to review by the OAL before it becomes effective. If it is approved by OAL, the Policy would be subject to further review by the courts. Given the numerous variables and factors involved in calculating the potential costs of closed-cycle cooling systems, any decision to install such a system would be made on a case-by-case basis considering all relevant factors at the time. If capital expenditure requirements related to cooling water systems become great enough to render the continued operation of a particular plant uneconomical, we could, at our option, and subject to any applicable financing agreements and other obligations, reduce operations or cease to operate the plant and forego such capital expenditures. We have no plans, at this time, to install a closed cycle cooling system at the South Bay power generation facility.

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New York Water Intake Policy. On March 4, 2010, the NYSDEC issued a draft policy ("the NYSDEC Policy") on "BTA for Cooling Water Intake Structures." The NYSDEC Policy, which was subject to comment until July 8, 2010, would establish closed cycle cooling or its equivalent as the minimum performance goal for existing power plants. If NYSDEC determines that closed cycle cooling is not available for a facility, the NYSDEC Policy would establish a performance goal of 90 percent or greater reduction in impingement mortality and entrainment from that which could be achieved by closed cycle cooling. The NYSDEC Policy would exempt certain power generation facilities that operate at very low capacity. We are continuing to review the potential impact of the NYSDEC Policy, if adopted, on our subject power generation facilities.

Coal Combustion Residuals. On May 4, 2010, the EPA released two alternative proposals for federal regulation of the management and disposal of CCR from electric utilities and independent power producers. The agency proposed two alternative approaches for regulating these materials under the RCRA. One proposal would regulate CCR as a special waste under subtitle C rules when those wastes are destined for disposal in a landfill or surface impoundment. The subtitle C proposal would subject persons who generate, transport, treat, store or dispose of such CCR to many of the existing RCRA regulations applicable to hazardous waste. Certain types of beneficial use of CCR would be exempt from regulation under the subtitle C proposal. Regulation under subtitle C would effectively phase out the use of ash ponds for disposal of CCR.

The second alternative proposal would regulate CCR disposed in landfills or surface impoundments as a solid waste under subtitle D of RCRA. The subtitle D proposal would establish national criteria for disposal of CCR in landfills and surface impoundments, requiring new units to install composite liners. The subtitle D proposal might also require existing surface impoundments without liners to close or be retrofitted with composite liners within five years.

These proposals were published in the Federal Register on June 21, 2010 and comments are due on or before September 20, 2010. The timing and ultimate requirements of a final rule governing CCR , as well as options available for compliance cannot be predicted with confidence at this time. Such a rule could have a material adverse effect on our financial condition, results of operations and cash flows. Please read Item 1. Business—Other Environmental Matters—Coal Combustion Byproducts in our Form 10-K for further discussion.

Interstate Transport Rule. On July 6, 2010, the EPA released its proposed Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (the "proposed Transport Rule"). The proposed Transport Rule would be implemented through federal implementation plans that would be effective in each affected state as soon as the final rule is issued. The proposed rules are intended to reduce emissions of SO2 and NOX from large electric generating units in 31 eastern states and the District of Columbia. The rules would impose cap and trade programs within each state that would cap emissions of SO2 and NOX at levels predicted to eliminate that state's contribution to nonattainment in, or interference with maintenance of attainment status by, down-wind areas to the east with respect to the National Ambient Air Quality Standards for particulate matter (PM2.5) and ozone. Our generating facilities in Illinois, New York and Pennsylvania would be subject to the rules.

The rules applicable to annual and ozone season NOX emissions would require compliance by January 1, 2012. The rules applicable to SO2 emissions from electric generating units in Illinois, New York and Pennsylvania would be implemented in two stages with compliance dates of January 1, 2012 and January 1, 2014. EPA would initially allocate NOX and SO2 emission allowances to existing electric generating units based on the lower of 2009 annual emissions or projected 2012 emissions necessary to meet EPA's emission budget for the state. The SO2 emission budgets in Illinois, New York and Pennsylvania would be reduced in 2014, and existing electric generating units in these states would be allocated fewer SO2 emission allowances beginning in 2014. Electric generating units would be required to hold one emission allowance for every ton of SO2 and/or NOX emitted during the applicable compliance period. Electric generating units can comply with the required emission reductions by any combination of (i) installing emission control technologies, (ii) operating existing emission controls more often, (iii) switching fuels, or

(iv) curtailing or ceasing operation.

Allowance trading would be allowed under the proposed Transport Rule among sources within the same state, with limited interstate allowance trading. Illinois, New York and Pennsylvania would be subject to three new cap and trade programs under the proposed Transport Rule capping emissions of NOX from May 1st through September 30th and capping emissions of SO2 and NOX respectively, on an annual basis.

In the preamble to the proposed Transport Rule, the EPA solicits comments on alternatives and variations to a number of provisions of the proposal including the state emissions budgets, the emission allowance allocation approach, auction of allowances rather than allocation by the EPA, and direct control of emissions through emission rate limits. We will continue to monitor the rulemaking process surrounding the proposed Transport Rule and any potential impacts it might have on our operations.

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Financial Reform Legislation. On July 21, 2010, Financial Reform Legislation was signed into law. The legislation primarily provides broad impacts to the financial services industry. However, among its provisions are requirements for OTC derivatives transactions. We use a variety of these transactions in connection with the purchase and sale of electricity and fuel, as well as to support our risk management practices. The legislation provides an end-user exemption that may excuse asset-based energy companies from independent exchange clearing and collateralization requirements that otherwise apply to OTC derivative transactions. Regardless of how end-user exemptions are ultimately determined, we use a collateral clearing agent, with the majority of our transactions collateralized with cash, short-term investments, or availability under our term letter of credit facility. We will continue to monitor for potential impacts as regulatory entities develop regulations necessary for implementing the legislation.

RISK-MANAGEMENT DISCLOSURES

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

	As of and for the Six Months Ended June 30, 2010 (in millions)
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at December 31, 2009	$(33)
Risk-management gains recognized through the income statement in the period, net	109
Cash received related to risk-management contracts settled in the period, net	(117)
Changes in fair value as a result of a change in valuation technique (1)	—
Non-cash adjustments and other (2)	49
Fair value of portfolio at June 30, 2010	$8

(1) Our modeling methodology has been consistently applied.
(2) Includes the reduction of $50 million of risk management activity as of January 1, 2010 due to the deconsolidation of PPEA Holding. Please read Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities for further discussion.

The net risk management asset of $8 million is the aggregate of the following line items on our unaudited condensed consolidated balance sheets: Current Assets—Assets from risk-management activities, Other Assets—Assets from risk-management activities, Current Liabilities—Liabilities from risk-management activities and Other Liabilities—Liabilities from risk-management activities.

Risk-Management Asset and Liability Disclosures. The following table provides an assessment of net contract values by year as of June 30, 2010, based on our valuation methodology:

Net Fair Value of Risk-Management Portfolio

Total	2010	2011	2012	2013	2014	Thereafter
			(in millions)			
$3	$26	$1	$(24)	$—	$—	$—

Market quotations (1)							
Prices based on models(2)(3)	5	17	7	(22)	—	1	2
Total	$8	$43	$8	$(46)	$—	$1	$2

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

(2) The market quotations and prices based on models categorization differs from the fair value accounting standards' categories of Level 1, Level 2 and Level 3 due to the application of the different methodologies. Please see Note 6—Fair Value Measurements for further discussion.

(3) The majority of the $17 million in 2010 is for instances where industry-standard models are used but the pricing inputs combine broker quotes for a liquid delivery hub with broker quotes for the price spread between the liquid delivery hub and the location under the contract. Therefore, the value is included in the prices based on models category.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

This Form 10-Q includes statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward-looking statements". All statements included or incorporated by reference in this quarterly report, other than statements of historical fact, that address activities, events or developments that we or our management expect, believe or anticipate will or may occur in the future are forward-looking statements. These statements represent our reasonable judgment on the future based on various factors and using numerous assumptions and are subject to known and unknown risks, uncertainties and other factors that could cause our actual results and financial position to differ materially from those contemplated by the statements. You can identify these statements by the fact that they do not relate strictly to historical or current facts. They use words such as "anticipate", "estimate", "project", "forecast", "plan", "may", "will", "should", "expect" and other words of similar meaning. In particular, these includ are not limited to, statements relating to the following:

- the timing and anticipated benefits to be achieved through our 2010-2013 company-wide cost reduction program;
- beliefs and assumptions relating to liquidity, available borrowing capacity and capital resources generally;
- expectations regarding environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts, and other laws and regulations to which we are, or could become, subject;
- beliefs about the overall economy, demand for power, commodity pricing and generation volumes;

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- anticipated liquidity in the regional power and fuel markets in which we transact, including the extent to which such liquidity could be affected by poor economic and financial market conditions or new regulations and any resulting impacts on financial institutions and other current and potential counterparties;
- sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation thereof;
- beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale power generation market, including the anticipation of higher market pricing over the longer term;
- the possibility of further consolidation of the power generation industry and the impact of any such activity on Dynegy;
- the beliefs and assumptions regarding our ability to enhance long-term value for stockholders;
- the effectiveness of our strategies to capture opportunities presented by changes in commodity prices and to manage our exposure to energy price volatility;
- beliefs and assumptions about weather and general economic conditions;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- expectations regarding our revolver capacity, credit facility compliance, financial covenants, collateral demands, capital expenditures, interest expense and other payments;
- beliefs or expectations regarding the potential amendment, extension or refinancing of our Credit Facility, or the timing thereof;
- our focus on safety and our ability to efficiently operate our assets so as to maximize our revenue generating opportunities and operating margins;
- beliefs about the outcome of legal, regulatory, administrative and legislative matters; and
- expectations and estimates regarding capital and maintenance expenditures, including the Midwest Consent Decree and its associated costs.

Any or all of our forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors, many of which are beyond our control, including those set forth under Part II–Other Information, Item 1A-Risk Factors and Item 1A-Risk Factors of our Form 10-K.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 1—Accounting Policies to the unaudited condensed consolidated financial statements for a discussion of recently issued accounting pronouncements affecting us.

CRITICAL ACCOUNTING POLICIES

Estimated Useful Lives. The estimated useful lives of our long–lived assets are used to compute depreciation expense, future AROs and are used in impairment testing. Estimated useful lives are based, among other things, on the assumption that we provide an appropriate level of capital expenditures while the assets are still in operation. Estimated lives could be impacted by such factors as future energy prices, environmental regulations, various legal factors and competition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future AROs may be insufficient and impairments in carrying values of tangible and intangible assets may result.

Please read "Critical Accounting Policies" in our Form 10-K for a complete description of our critical accounting policies, with respect to which there have been no material changes since the filing of such Form 10-K.

Item 3—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK—DYNEGY INC. AND DYNEGY HOLDINGS INC.

Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our Form 10-K for a discussion of our exposure to commodity price variability and other market risks related to our net non-trading derivative assets and liabilities, including foreign currency exchange rate risk. Following is a discussion of the more material of these risks and our relative exposures as of June 30, 2010.

Value at Risk ("VaR"). The following table sets forth the aggregate daily VaR of the mark-to-market portion of our risk-management portfolio primarily associated with the GEN segments and the remaining legacy customer risk management business. The VaR calculation does not include market risks associated with the accrual portion of the risk-management portfolio that is designated as a cash flow hedge or a "normal purchase normal sale", nor does it include expected future production from our generating assets. Please read "Value at Risk" in our Form 10-K for a complete description of our valuation methodology.

Daily and Average VaR for Risk-Management Portfolios

	June 30, 2010	December 31, 2009
	(in millions)	
One day VaR—95 percent confidence level (1)	$20	$41
One day VaR—99 percent confidence level (1)	$29	$57
Average VaR for the year-to-date period—95 percent confidence level (1)	$29	$34

(1) The decrease in the June 30, 2010 VaR was primarily due to lower commodity price and historical volatility levels as compared to December 31, 2009.

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Credit Risk. The following table represents our credit exposure at June 30, 2010 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary

	Investment Grade Quality	Non-Investment Grade Quality (in millions)	Total
Type of Business:			
Financial institutions	$25	$ —	$25
Utility and power generators	11	—	11
Commercial, industrial and end users	1	—	1
Oil and gas producers	2	—	2
Total	$39	$ —	$39

Interest Rate Risk. We are exposed to fluctuating interest rates related to variable rate financial obligations. As of June 30, 2010, our fixed rate debt instruments, as a percentage of total debt instruments, were approximately 80 percent. The net notional fixed rate debt as a percentage of total debt was approximately 80 percent. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of June 30, 2010, it is estimated that a one percentage point interest rate movement in the average market interest rates (either higher or lower) over the 12 months ended June 30, 2010 would either decrease or increase interest expense by approximately $9 million. This exposure would be partially offset by an approximate $9 million increase or decrease in interest income related to the restricted cash balance of $850 million posted as collateral to support the term letter of credit facility. Over time, we may seek to reduce or increase the percentage of fixed rate financial obligations in our debt portfolio through the use of swaps or other financial instruments.

The notional financial contract amounts associated with our interest rate contracts were as follows at June 30, 2010 and December 31, 2009, respectively:

	June 30, 2010	December 31, 2009
Fair value hedge interest rate swaps (in millions of U.S. dollars)	$25	$25
Fixed interest rate received on swaps (percent)	5.70	5.70
Interest rate risk-management contract (in millions of U.S. dollars) (1)	$231	$784
Fixed interest rate paid on swaps (percent)	5.35	5.33
Interest rate risk-management contract (in millions of U.S. dollars)	$206	$206
Fixed interest rate received on swaps (percent)	5.28	5.28

(1) Reflects the reduction of $553 million of notional financial contract amounts due to the deconsolidation of PPEA Holding. Please read Note 1—Accounting Policies—Accounting Policies Adopted—Variable Interest Entities for further discussion.

Item 4—CONTROLS AND PROCEDURES—DYNEGY INC. AND DYNEGY HOLDINGS INC.

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of Dynegy’s and DHI’s management, including their Chief Executive Officer and their Chief Financial Officer, of the effectiveness of the design and operation of Dynegy’s and DHI’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended). This evaluation included consideration of the various processes carried out under the direction of Dynegy’s disclosure committee. This evaluation also considered the work completed relating to Dynegy’s and DHI’s compliance with Section 404 of the Sarbanes-Oxley Act of 2002. Based on this evaluation, Dynegy’s and DHI’s CEO and CFO concluded that Dynegy’s and DHI’s disclosure controls and procedures were effective as of June 30, 2010.

Changes in Internal Controls Over Financial Reporting

There were no changes in Dynegy’s and DHI’s internal control over financial reporting that have materially affected or are reasonably likely to materially affect Dynegy’s and DHI’s internal control over financial reporting during the quarter ended June 30, 2010.

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DYNEGY INC. and DYNEGY HOLDINGS INC.

PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS—DYNEGY INC. AND DYNEGY HOLDINGS INC.

See Note 12—Commitments and Contingencies—Legal Proceedings to the accompanying unaudited condensed consolidated financial statements for a discussion of the legal proceedings that we believe could be material to us.

Item 1A—RISK FACTORS—DYNEGY INC. AND DYNEGY HOLDINGS INC.

See Item 1A—Risk Factors, of our Form 10-K for factors, risks and uncertainties that may affect future results.

Item 2—UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS—DYNEGY INC.

Upon vesting of restricted stock awarded by Dynegy to employees, shares are withheld to cover the employees' withholding taxes. Information on Dynegy's deemed purchases of equity securities for that purpose during the quarter follows:

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
April 1-30	49,321	$6.25	—	N/A
May 1-31	104	$6.60	—	N/A
June 1-30	16	$6.25	—	N/A
Total	49,441	$6.25	—	N/A

These were the only purchases of equity securities made by us during the three months ended June 30, 2010. Dynegy does not have a stock repurchase program.

Item 6—EXHIBITS—DYNEGY INC. AND DYNEGY HOLDINGS INC.

The following documents are included as exhibits to this Form 10-Q

Exhibit Number	Description
3.1	Dynegy's Second Amended and Restated Certificate of Incorporation, amended as of May 21, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on May 25, 2010).
10.1	Dynegy Inc. 2010 Long Term Incentive Plan (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-8 of Dynegy Inc. filed on May 26, 2010).

10.2	Facility and Security Agreement, executed May 21, 2010 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on May 25, 2010).
10.3	The Global Amendment to Equity-Based Compensation Agreements, executed on May 25, 2010 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on May 25, 2010).
*10.4	Second Amendment to the Dynegy Inc. Restoration Pension Plan, executed on July 2, 2010.
*31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.1(a)	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2(a)	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.1(a)	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2(a)	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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* Filed herewith.

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

** XBRL information is furnished and not filed for purposes of Section 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 193, and is not subject to liability under those sections, is not part of any registration statement or prospectus to which it relates and is not incorporated or deemed to be incorporated by reference into any registration statement, prospectus or other document.

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DYNEGY INC. and DYNEGY HOLDINGS INC.

SIGNATURES

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

DYNEGY INC.

Date: August 6, 2010	By: /s/ HOLLI C. NICHOLS Holli C. Nichols Executive Vice President and Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)

DYNEGY HOLDINGS INC.

Date: August 6, 2010	By: /s/ HOLLI C. NICHOLS Holli C. Nichols Executive Vice President and Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)