DYNEGY INC.
Form 10-K
March 08, 2012

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

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

For the transition period from to

DYNEGY INC.

(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

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

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

Securities registered pursuant to Section12(b) of the Act:

Title of each class	Name of each exchange on which registered
Dynegy's common stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section12(g) of the Act:

None

(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No ý

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No ý

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. Yes ý No o

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). Yes ý No o

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

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

Large accelerated filer o	Accelerated filer ý	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No ý

As of June 30, 2011, the aggregate market value of the Dynegy Inc. common stock held by non-affiliates of the registrant was $644,913,117 based on the closing sale price as reported on the New York Stock Exchange.

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, 122,893,088 shares outstanding as of March 2, 2012.

DOCUMENTS INCORPORATED BY REFERENCE

Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant's 2012 Annual Meeting of Stockholders, which the registrant intends to file no later than 120 days after December 31, 2011. However, if such proxy statement is not filed within such 120-day period, Items 10,11,12,13 and 14 will be filed as part of an amendment to this Form 10-K no later than the end of the 120-day period.

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PART I

DEFINITIONS

Unless the context indicates otherwise, throughout this report, the terms "the Company," "we," "us," "our" and "ours" are used to refer to Dynegy Inc. and its direct and indirect subsidiaries as presented in our consolidated financial statements. Effective November 7, 2011, we deconsolidated Dynegy Holdings, LLC ("DH") and its consolidated subsidiaries, which included the operations of our Gas and DNE segments. Discussions or areas of this report that apply only to Dynegy, or DH, are clearly noted in such discussions or areas.

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

AMT	Alternative Minimum Tax
APIC	Additional Paid-in-Capital
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BACT	Best Available Control Technology (air)
BART	Best Available Retrofit Technology
BTA	Best technology available (water intake)
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	The California Independent System Operator
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CSAPR	Cross State Air Pollution Rule
CAVR	The Clean Air Visibility Rule
CCR	Coal Combustion Residuals
CEQA	California Environmental Quality Act
CERCLA	The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CO_2	Carbon dioxide
CO_2e	The climate change potential of other GHGs relative to the global warming potential of CO_2
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CPUC	California Public Utility Commission
CRM	Our former customer risk management business segment
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
CUSA	Chevron U.S.A. Inc.
DCIH	Dynegy Coal Intermediate Holdings, LLC
Debtor Entities	DH, Dynegy Northeast Generation, Inc., Hudson Power, L.L.C., Dynegy Danskammer, L.L.C. and Dynegy Roseton, L.L.C.
DGIN	Dynegy Gas Investments, LLC
DH	Dynegy Holdings, LLC (formerly known as Dynegy Holdings Inc.)
DMG	Dynegy Midwest Generation, LLC
DMSLP	Dynegy Midstream Services L.P.
DMT	Dynegy Marketing and Trade, LLC
DPC	Dynegy Power, LLC
DYPM	Dynegy Power Marketing Inc.
EBITDA	Earnings before interest, taxes, depreciation and amortization

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EGU	Electric generating unit
EPA	United States Environmental Protection Agency
ERISA	The Employee Retirement Income Security Act of 1974, as amended
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles of the United States of America
GEN Finance	Dynegy Gen Finance Company, LLC
GHG	Greenhouse gas
HAPs	Hazardous air pollutants, as defined by the Clean Air Act
ICAP	Installed capacity
ICC	Illinois Commerce Commission
IMA	In-Market Availability
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
LMP	Locational Marginal Pricing
LPG	Liquefied petroleum gas
LTIP	Long-Term Incentive Plan
MACT	Maximum achievable control technology
MGGA	Midwest Greenhouse Gas Accord
MGGRP	Midwestern Greenhouse Gas Reduction Program
MISO	Midwest Independent Transmission System Operator
MMBtu	Millions of British thermal units
MRTU	Market Redesign and Technology Update
MW	Megawatts
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NGL	Our former natural gas liquids business segment
NOL	Net operating loss
NO_x	Nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NRG	NRG Energy, Inc.
NSPS	New Source Performance Standard
NYISO	New York Independent System Operator
NYSDEC	New York State Department of Environmental Conservation
NYSE	New York Stock Exchange
OAL	Office of Administrative Law
OCI	Other Comprehensive Income
OTC	Over-the-counter
PJM	PJM Interconnection, LLC
PPEA	Plum Point Energy Associates
PPEA Holding	Plum Point Energy Associates Holding Company, LLC
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
PURPA	The Public Utility Regulatory Policies Act of 1978
PY	Planning Year
QF	Qualifying Facility

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RACT	Reasonably Available Control Technology
RCRA	The Resource Conservation and Recovery Act of 1976, as amended
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SCEA	Sandy Creek Energy Associates, LP
SCH	Sandy Creek Holdings, LLC
SEC	U.S. Securities and Exchange Commission
SCR	Selective Catalytic Reduction
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SPDES	State Pollutant Discharge Elimination System
VaR	Value at Risk
VCA	Voluntary Capacity Auction
VIE	Variable Interest Entity
VLGC	Very large gas carrier
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

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Item 1. ***Business***

THE COMPANY

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our primary business is the production and sale of electric energy, capacity and ancillary services from our fleet of sixteen operating power plants in six states totaling approximately 11,600 MW of generating capacity. Effective November 7, 2011, as a result of the Chapter 11 Cases (as discussed below), we deconsolidated DH and its consolidated subsidiaries, which included approximately 8,500 MW related to the operations of our Gas and DNE segments.

Dynegy began operations in 1984 and became incorporated in the State of Delaware in 2007. Our principal executive office is located at 1000 Louisiana Street, Suite 5800, Houston, Texas 77002, and our telephone number at that office is (713) 507-6400.

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

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

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

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Our Power Generation Portfolio

Our current operating generating facilities, including the operating generating facilities of DH, our wholly-owned equity investment, are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	Region
Dynegy Inc.:					
Baldwin	1,800	Coal	Baseload	Baldwin, IL	MISO
Havana(2)	441	Coal	Baseload	Havana, IL	MISO
Hennepin	293	Coal	Baseload	Hennepin, IL	MISO
Oglesby	63	Gas	Peaking	Oglesby, IL	MISO
Stallings	89	Gas	Peaking	Stallings, IL	MISO
Wood River(3)	446	Coal	Baseload	Alton, IL	MISO
Total Coal Segment	*3,132*				
Total Dynegy Inc.	*3,132*				
DH:					
Moss Landing Units 1-2	1,020	Gas	Intermediate	Monterey County, CA	CAISO
Units 6-7	1,509	Gas	Peaking	Monterey County, CA	CAISO
Kendall	1,200	Gas	Intermediate	Minooka, IL	PJM
Ontelaunee	580	Gas	Intermediate	Ontelaunee Township, PA	PJM
Morro Bay(4)	650	Gas	Peaking	Morro Bay, CA	CAISO
Oakland	165	Oil	Peaking	Oakland, CA	CAISO
Casco Bay	540	Gas	Intermediate	Veazie, ME	ISO-NE
Independence	1,064	Gas	Intermediate	Scriba, NY	NYISO
Black Mountain(5)	43	Gas	Baseload	Las Vegas, NV	WECC
Total Gas Segment	*6,771*				
Danskammer Units 1-2	123	Gas/Oil	Peaking	Newburgh, NY	NYISO
Units 3-4(6)	370	Coal/Gas	Baseload	Newburgh, NY	NYISO
Roseton(6)	1,200	Gas/Oil	Peaking	Newburgh, NY	NYISO
Total DNE Segment	*1,693*				
Total DH	*8,464*				
Total Fleet Capacity	*11,596*				

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(1) Unit capabilities are based on winter capacity.

(2) Represents Unit 6 generating capacity. Units 1-5, with a combined net generating capacity of 228 MW, are retired and out of operation.

(3) Represents Units 4 and 5 generating capacity. Units 1-3, with a combined net generating capacity of 119 MW, are currently in mothball status and out of operation.

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

(5)
DH indirectly owns a 50 percent interest in this facility. Total output capacity of this facility is 85 MW.

(6)
The Roseton facility and Units 3 and 4 of the Danskammer facility were leased by a subsidiary of DH. Please read Note 3 Chapter 11 Cases for further discussion.

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Business Strategy

Our business strategy is to create value through the safe, reliable and cost-efficient operation of our power generation assets. During 2011, we completed the Reorganization (as defined below) to better align our business around our generation assets and to more aggressively drive both financial and operational efficiencies across the Company. We now manage our generation assets by fuel type with three primary reportable segments: (i) the Coal segment ("Coal"), (ii) the Gas Segment ("Gas") and (iii) the Dynegy Northeast Segment ("DNE").

There are four primary elements to the Company's strategy:

Operational Excellence Operating our power plants in a safe, reliable, and environmentally compliant manner with a particular focus on increasing cash flow and optimizing availability;

Commercial Execution Optimizing the commercial results of the assets through proactive management of our power, fuel, capacity, and ancillary service positions with short-, medium-, and long-term agreements and hedging arrangements;

Corporate and Organizational Support Maximizing organizational effectiveness and efficiency through continuous business process improvements, operational enhancements, and cost management; and

Capital Structure Management Creating a sustainable and flexible capital structure with diversified liquidity sources to efficiently support our commercial activities.

Operational Excellence. We operate a portfolio of generation assets that is diversified in terms of dispatch profile, fuel type and geography. Our Coal segment is primarily a fleet of baseload coal facilities, located in Illinois, that dispatch around the clock throughout the year. Our Gas segment operates both intermediate and peaking natural gas plants, located in the Midwest, Northeast and California. The intermediate gas plants tend to be dispatched during periods of elevated electricity demand because their operational flexibility enables them to respond quickly to changes in market conditions. In addition to generating power, these assets also generate capacity revenues through structured markets or bilateral tolling agreements, as local utilities and ISOs seek to ensure sufficient generation capacity is available to meet future market demands. Peaking facilities are generally dispatched to serve load only during the highest periods of power demand, such as hot summer and cold winter days. In addition to the peaking plants within our Gas segment, our DNE segment manages three peaking units as well as two coal-fired generation units in New York.

We have historically achieved strong plant operations and are committed to operating all of our facilities in a safe, reliable, cost-efficient and environmentally compliant manner. We have dedicated significant resources toward these priorities with approximately $1 billion invested over the past several years in our Coal segment for environmental compliance initiatives to meet contractual obligations and state and federal environmental standards. In addition, we continue to invest approximately $90 million annually across all segments to maintain and improve the safety, reliability, and efficiency of the fleet. The recent reorganization of our segments by fuel type helps facilitate and realize best operating practices across the respective portfolios, leading to additional cost efficiencies and improved operating practices.

Commercial Execution. Our commercial strategy seeks to optimize the value of our assets by locking in near-term cash flow while preserving the ability to capture higher values longer-term as power markets improve. We seek to capture both intrinsic as well as extrinsic value of the coal and gas portfolios. Intrinsic value is represented by cash flow generated from selling power at market prices; extrinsic value is represented by characteristics of our fleet that can generate incremental economics due to market volatility, differences in counterparties' views of forward prices and other market conditions. In order to execute our commercial strategy, we utilize a wide range of products and contracts such as tolling agreements, fuel supply contracts, capacity auctions, bilateral capacity contracts, power and natural gas swap agreements, power and natural gas options and other financial instruments.

Power prices have fallen significantly over the past few years primarily as a result of the decline in natural gas prices and a weakened national economy. Despite these near-term dynamics, we continue to believe that, over the longer-term, power demand and power pricing will improve as the economy rebounds, marginal generating units retire, and more stringent environmental regulations force the retirement of power generation units that have not invested in environmental upgrades. As a result, we believe our coal-fired baseload fleet, with its environmental upgrades, is positioned to benefit from higher power prices in the Midwest. We also believe these same factors will benefit our combined cycle units through increased run-times and higher power prices as heat rates expand resulting in improved margins and cash flows.

We volumetrically hedge the expected output from our facilities over a rolling one- to three-year time frame with the goal of stabilizing near-term earnings and cash flow while preserving upside potential should commodity prices or market factors improve. We manage our hedging program within the limits of our available liquidity sources. These sources include cash, letter of credit capacity, and the recently reinstituted first lien collateral structure with select counterparties, which has provided substantially more liquidity. We expect to broaden the use of this collateral structure to include additional counterparties in the future. While this initiative provides an alternative source of liquidity support, it also removes significant liquidity risk as fluctuations in commodity prices no longer impact cash balances and letter of credit availability. As a result, we have the ability to execute more sizeable and longer-term hedges when market opportunities arise.

Corporate and Organizational Support. During 2011, we initiated a new cost and performance improvement initiative, known as PRIDE ("Producing Results through Innovation by Dynegy Employees"), which is designed to drive recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency. In 2011 alone, we recognized $64 million in operating margin and cost improvements versus 2010 and $376 million in incremental liquidity from balance sheet improvements due to PRIDE initiatives. In 2012, we are targeting additional margin and cost improvements of $40 million, and additional balance sheet improvements of $100 million. We will continue to use the PRIDE initiative to improve our operating performance, cost structure and balance sheet.

Capital Structure Management. The power industry is a cyclical commodity business with significant price volatility and considerable capital investment requirements. As such, it is imperative to build and maintain a balance sheet characterized by manageable debt levels and a multi-faceted liquidity program. We have undertaken to restructure our long-term debt and lease obligations through a voluntary Chapter 11 process for certain of our subsidiaries. We anticipate that the Debtor Entities (as defined below) will emerge from bankruptcy during 2012 having achieved a more sustainable leverage profile that provides sufficient flexibility to manage and grow the business throughout the commodity cycle. We are also focused on building a more diverse liquidity program to support our ongoing operations and commercial activities. In addition to our existing cash balances and letter of credit facilities, we are actively pursuing additional liquidity including the expansion of our first lien collateral program with additional hedging counterparties and other options that add liquidity for general corporate purposes to ensure that we have the financial resources to deliver on all of our strategic initiatives.

Reorganization

In August 2011, we completed an internal reorganization of our subsidiaries (the "Reorganization"), as a result of which (i) substantially all of our coal-fired power generation facilities are held by Dynegy Midwest Generation, LLC ("DMG"), (ii) substantially all of our natural gas-fired power generation facilities are held by Dynegy Power, LLC ("DPC"), an indirect wholly-owned subsidiary of Dynegy Holdings, LLC ("DH") and (iii) 100 percent of the ownership interests in Dynegy Northeast Generation, Inc., the entity that indirectly holds the equity interests in the subsidiaries that operate the Roseton and Danskammer power generation facilities, including the leased units, are held by DH. As a result of the Reorganization, DPC owns a portfolio of eight primarily natural gas-fired intermediate (combined cycle) and peaking (combustion and steam turbines) power generation facilities diversified across the West, Midwest and Northeast regions of the United States, totaling 6,771 MW of generating capacity. DMG owns a portfolio of six primarily coal-fired baseload power generation facilities located in the Midwest, totaling 3,132 MW of generating capacity.

The DPC and DMG asset portfolios were designed to (i) leverage best practices across our fleet and (ii) be separately financeable and bankruptcy remote. On August 5, 2011, DPC and its parent Dynegy Gas Investments Holdings, LLC ("DGIH"), each an indirect subsidiary of DH, entered into a $1.1 billion, five-year senior secured term loan facility (the "DPC Credit Agreement"). The same day, DMG and its parent Dynegy Coal Investments Holdings, LLC, each then also an indirect subsidiary of DH, entered into a $600 million, five-year senior secured term loan facility (the "DMG Credit Agreement" and together with the DPC Credit Agreement, the "New Credit Agreements"). Proceeds from these New Credit Agreements enabled DH to repay its outstanding indebtedness under DH's Fifth Amended and Restated Credit Agreement and Sithe Senior Notes, and are available to DPC and DMG to be used for general working capital and general corporate purposes. Please read Note 19 Debt DMG Credit Agreement and DH Debt Obligations DPC Credit Agreement for further discussion of the New Credit Agreements. Our remaining assets (including our leasehold interests in the Danskammer and Roseton facilities) are not a part of either DPC or DMG.

Overview of Bankruptcy Remote and Ring-Fencing Measures. In connection with the Reorganization, new companies were created, some of which are "bankruptcy remote." In addition, as part of the Reorganization, some companies within our portfolio were reorganized into ring-fenced companies to facilitate our financing efforts by maintaining certain of our entities and their assets separate from other entities and their assets. The new special purpose bankruptcy remote entities entered into limited liability company operating agreements, which contain certain restrictions including not allowing the "bankruptcy remote" or "ring-fenced" companies to act as an agent for a non ring-fenced company. Furthermore, bankruptcy remote and ring-fenced companies are required to present themselves to the public as separate entities and correct any misunderstandings that they are not separate entities, maintain separate books, records and bank accounts and separately appoint officers. Additionally, they pay liabilities from their own funds, they conduct business in their own names (other than any business relating to trading activities), they observe a higher level of formalities, and the ring-fenced entities have restrictions on pledging their assets for the benefit of certain other persons. Our ring-fenced entities include entities that own, directly or indirectly, the assets included in our Coal and Gas segments and such assets are available to satisfy the claims of creditors of such ring-fenced entities.

Further, the bankruptcy remote entities each have one independent manager. For these bankruptcy remote entities unanimous consent of such entity's board of managers, including the independent manager, is required for filing any bankruptcy proceeding, seeking or consenting to the appointment of any receiver, making or consenting to any assignment for the benefit of creditors, admitting in writing the inability to pay the entity's debts, consenting to substantive consolidation, dissolving or liquidating, engaging in any business beyond those set forth in the entity's organizational documents, amending the bankruptcy remoteness provisions in such entity's organizational documents and, at any time following execution of an applicable credit agreement, amending, terminating or entering into material relationships with other related entities. Our bankruptcy remote entities include both entities that are included in the ring-fenced structure and entities outside of the ring-fenced structures.

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DMG Transfer. On September 1, 2011, Dynegy and Dynegy Gas Investments, LLC ("DGIN"), a subsidiary of DH, entered into a Membership Interest Purchase Agreement whereby DGIN transferred 100 percent of its outstanding membership interests of Dynegy Coal HoldCo, LLC ("Coal HoldCo") which through DMG owns Dynegy's portfolio of primarily coal-fired generation facilities, to Dynegy (the "DMG Transfer"). In exchange for Coal HoldCo, Dynegy agreed to make certain specified payments (aggregating approximately $2.1 billion through October 15, 2026) to DGIN over time which coincide in timing and amount to the payments of principal and interest that DH is obligated to make with respect to a portion of certain of DH's senior notes (the "Undertaking Agreement"). DGIN assigned its rights to receive payments under the Undertaking Agreement to DH in exchange for a promissory note (the "Promissory Note") in the amount of $1.25 billion that matures in 2027 (the "Assignment"). As a condition to Dynegy's consent to the Assignment, the Undertaking Agreement was amended and restated to be between DH and Dynegy and to provide for the reduction of Dynegy's obligations if the outstanding principal amount of the senior notes decreases as a result of any exchange offer, tender offer or other purchase or repayment by Dynegy or its subsidiaries (other than DH and its subsidiaries, unless Dynegy guarantees the debt securities of DH or such subsidiary in connection with such exchange offer, tender offer or other purchase or repayment); provided that such principal amount is retired, cancelled or otherwise forgiven. Upon the Effective Date (as defined below), Dynegy and DH will cancel the Undertaking Agreement and Dynegy's obligations under the Undertaking Agreement will be fully satisfied and extinguished. For further discussion, please read Note 20 Related Party Transactions Undertaking Agreement.

Chapter 11 Filing by Certain Subsidiaries

On November 7, 2011, DH and four of its wholly-owned subsidiaries, Dynegy Northeast Generation, Inc., Hudson Power, L.L.C., Dynegy Danskammer, L.L.C. and Dynegy Roseton, L.L.C. (collectively, the "Debtor Entities") filed voluntary petitions (the "Chapter 11 Cases") for relief under Chapter 11 of Title 11 of the United States Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of New York, Poughkeepsie Division (the "Bankruptcy Court"). The Chapter 11 Cases were assigned to the Honorable Cecelia G. Morris and are being jointly administered for procedural purposes only. Dynegy and its subsidiaries, other than the five Debtor Entities, did not file voluntary petitions for relief and are not debtors under Chapter 11 of the Bankruptcy Code and, consequently, will continue to operate their business in the ordinary course.

The normal day-to-day operations of the coal-fired power generation facilities held by DMG and the gas-fired power generation facilities held by DPC have continued without interruption. The commencement of the Chapter 11 Cases did not constitute a default under either of the New Credit Agreements.

In connection with the Chapter 11 Cases, DH, as lender, and the other Debtor Entities, as borrowers, entered into a $15 million intercompany revolving loan agreement, on an unsecured priority basis, that is available to the borrowers to fulfill working capital and other administrative funding needs during the Chapter 11 Cases.

On November 7, 2011, the Debtor Entities filed a motion with the Bankruptcy Court for authorization to reject the leases of the Roseton and Danskammer power generation facilities. On December 20, 2011, the Bankruptcy Court entered a stipulated order approving the rejection of such leases, as amended by a stipulated order entered by the Bankruptcy Court on December 28, 2011, subject, among other things, to the later determination of the effective date of the rejection and the amount of the damages claim resulting from the rejection. The Debtor Entities have remained in physical possession of, and have continued to operate the leased facilities to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facilities is permitted to be transitioned.

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On November 11, 2011, the successor indenture trustee under the Roseton and Danskammer indenture agreements (the "Lease Indenture Trustee") filed a motion with the Bankruptcy Court seeking the appointment of an examiner. On December 29, 2011, the Bankruptcy Court entered an order directing the appointment of the examiner, which order provides, among other things, that the examiner will investigate (i) the Debtor Entities' conduct in connection with the prepetition 2011 restructuring and reorganization of the Debtor Entities and their non-Debtor affiliates, (ii) any possible fraudulent conveyances, and (iii) whether DH is capable of confirming a Chapter 11 plan. Please read Note 3 Chapter 11 Cases for further discussion.

Restructuring Support Agreements. Prior to the commencement of the Chapter 11 Cases, DH and Dynegy reached an agreement with certain holders of more than $1.4 billion of DH's unsecured senior notes and debentures regarding a potential consensual restructuring (the "Restructuring") of over $4.0 billion of obligations owed by DH. The principal terms of the Restructuring were evidenced by a restructuring support agreement and related term sheet, dated November 7, 2011, which was amended and restated on December 26, 2011 (as amended and restated, the "Noteholder Restructuring Support Agreement"), and entered into by and among Dynegy, DH and the holders of approximately $1.8 billion of DH's unsecured senior notes and debentures and subordinated debentures (the "Consenting Noteholders"). For further discussion, please read Note 3 Chapter 11 Cases Noteholder Restructuring Support Agreement.

In addition, on December 13, 2011, we entered into a binding term sheet with Resources Capital Management Corporation and certain of its affiliates and subsidiaries ("PSEG"), to settle and resolve all issues in lieu of further litigation, regarding, among other things, the Roseton and Danskammer leases and all of the parties' rights and claims arising under the related lease documents, including certain tax indemnity agreements, pursuant to which settlement, PSEG agreed to support the confirmation of the Debtor Entities' plan of reorganization, bringing the aggregate amount of claims agreeing to support the plan up to approximately $1.9 billion.

Plan of Reorganization. On December 1, 2011, Dynegy and DH, as co-plan proponents, filed a proposed Chapter 11 plan of reorganization and a related disclosure statement for DH with the Bankruptcy Court. On January 19, 2012, they filed a proposed amended plan and related disclosure statement, and recently filed a second amended plan (the "Plan") and related disclosure statement (the "Disclosure Statement") with the Bankruptcy Court. The Plan addresses claims against and interests in DH only and does not address claims against and interests in the other Debtor Entities.

The proposed Plan sets forth the material terms of the Restructuring pursuant to which unsecured claims of DH, including its outstanding unsecured senior notes and debentures and subordinated debentures, will be cancelled and exchanged for a combination of (i) $1.015 billion aggregate principal amount of new secured notes ("New Secured Notes") of Dynegy (or a cash payment in lieu thereof), (ii) $2.1 billion of mandatorily convertible preferred stock of Dynegy (the "Preferred Stock") and (iii) $400 million cash (plus an amount equal to all interest that would have accrued on the New Secured Notes from the filing date of the Chapter 11 Cases). Our existing Dynegy common stock will remain outstanding. The New Secured Notes will be secured by a first priority security interest in (subject to certain exceptions and permitted liens): (i) the assets of certain of our direct and indirect wholly-owned subsidiaries (including a first priority security interest in and lien on a $55 million debt service account) and (ii) the equity interests in certain of our direct and indirect subsidiaries. Further, pursuant to the proposed Plan, it is a condition to the effective date of such plan (the "Effective Date") that the rejection damages arising from the rejection of the leases of the Roseton and Danskammer power generation facilities are determined in an amount not to exceed $300 million (or $190 million net of the claim of PSEG, which has already been allowed by the Bankruptcy Court in the amount of $110 million), subject only to a potential waiver. For further discussion, including a description of the New Secured Notes and Preferred Stock, please read Note 3 Chapter 11 Cases Plan of Reorganization.

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Accounting Impact. In conjunction with the commencement of the Chapter 11 Cases, we evaluated whether we should continue to consolidate DH and its wholly-owned subsidiaries, including the other Debtor Entities as well as the DH subsidiaries included in our Gas segment. We concluded that, because of the Chapter 11 Cases, under applicable accounting standards, we are no longer deemed to have a controlling financial interest in DH and its wholly-owned subsidiaries, and therefore, DH and its consolidated subsidiaries should no longer be consolidated in our consolidated financial statements as of November 7, 2011. We believe that control over DH and its consolidated subsidiaries will likely revert to us upon emergence of DH from bankruptcy, and as a result we will re-consolidate our investment in DH and its wholly-owned subsidiaries at such time. Our analysis and accounting conclusions were based on the applicable facts and circumstances applying accounting guidance and did not, and do not, represent legal conclusions. For further discussion, please read Note 3 Chapter 11 Cases Accounting Impact.

We previously disclosed in our 2010 Form 10-K our plans to continue as a going concern, due primarily to concerns regarding lower power prices and potential noncompliance with financial covenants contained in DH's former Fifth Amended and Restated Credit Agreement. During 2011, while lower power prices continued, we have accomplished certain significant milestones which have improved our liquidity projections and allowed us to continue as a going concern. These milestones include:

- DMG and DPC entered into the New Credit Agreements on August 5, 2011 which resulted in the repayment in full and termination of commitments under DH's former Fifth Amended and Restated Credit Agreement.

- We increased the use of the first lien collateral structure which not only provides an alternative source of liquidity, it also removes significant liquidity risk as fluctuations in commodity prices have a less significant impact on cash balances and letter of credit availability.

- We initiated a new cost and performance improvement initiative, known as PRIDE, which is designed to drive recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency.

- The Debtor Entities filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code allowing for the restructuring of our long-term debt and lease obligations. As a result, we deconsolidated DH and its subsidiaries as we concluded, under applicable accounting standards, we no longer have a controlling financial interest in DH and its wholly-owned subsidiaries. Effective with the deconsolidation and write down of our investment in DH, we no longer included DH and its subsidiaries' assets or liabilities in our liquidity analysis with respect to Dynegy Inc.'s accompanying financial statements. If the Plan is approved by the bankruptcy court, we will re-assess consolidation of DH and its subsidiaries at that time. However, we believe it is likely that control of DH and its subsidiaries will revert to us upon emergence of DH from bankruptcy, and as a result we will likely re-consolidate our investment in DH and its subsidiaries at that time.

The ultimate outcome of the Chapter 11 Cases and the impact to us is uncertain at this time. Please read Note 3 Chapter 11 Cases and Note 23 Commitments and Contingencies for further discussion.

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The following is an abbreviated organizational structuring depicting our organizational structure, including the Debtor Entities and the other entities that were deconsolidated effective November 7, 2011:

(1) There are other additional Dynegy entities not depicted in the above abbreviated organizational structure.

MARKET DISCUSSION

Our business operations are focused primarily on the wholesale power generation sector of the energy industry. During 2011, we reorganized and now manage and report the results of our power generation business based on fuel type with three segments on a consolidated basis: (i) Coal, (ii) Gas and (iii) DNE.

NERC Regions, RTOs and ISOs. In discussing our business, we often refer to NERC regions. The NERC and its regional reliability entities were formed to ensure the reliability and security of the electricity system. The regional reliability entities set standards for reliable operation and maintenance of power generation facilities and transmission systems. For example, each NERC region establishes a minimum operating reserve requirement to ensure there is sufficient generating capacity to meet expected demand within its region. Each NERC region reports seasonally and annually on the status of generation and transmission in each region.

Separately, RTOs and ISOs administer the transmission infrastructure and markets across a regional footprint in most of the markets in which we operate. They are responsible for dispatching all generation facilities in their respective footprints and are responsible for both maximum utilization and reliable and efficient operation of the transmission system. RTOs and ISOs administer energy and ancillary service markets in the short term, usually day ahead and real-time markets. Several RTOs and ISOs also ensure long-term planning reserves through monthly, semi-annual, annual and multi-year

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capacity markets. The RTOs and ISOs that oversee most of the wholesale power markets in which we operate currently impose, and will likely continue to impose, both bid and price limits. They may also enforce caps and other mechanisms to guard against the exercise of market dominance in these markets. NERC regions and RTOs/ISOs often have different geographic footprints, and while there may be geographic overlap between NERC regions and RTOs/ISOs, their respective roles and responsibilities do not generally overlap.

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

Market-Based Rates. Our ability to charge market-based rates for wholesale sales of electricity, as opposed to cost-based rates, is governed by FERC. We have been granted market-based rate authority for wholesale power sales from our EWG facilities, as well as wholesale power sales by our power marketing entities, DYPM and DMT. The Dynegy EWG facilities include all of our facilities except our investment in the Nevada Cogeneration Associates #2 ("Black Mountain") facility. This facility is known as a QF, and has various exemptions from federal regulation and sells electricity directly to purchasers under negotiated and previously approved power purchase agreements.

Our market-based rate authority is predicated on a finding by FERC that our entities with market-based rates do not have market power, and a market power analysis is generally conducted once every three years for each region on a rolling basis (known as the triennial market power review).

Coal Segment

Our Coal segment is comprised of four operating coal-fired power generation facilities and two operating natural gas-fired peaker facilities in Illinois with a total generating capacity of 3,132 MW. On November 17, 2011, we permanently retired the 176 MW Vermilion power generation facility. As of December 31, 2011, the facilities operated entirely within MISO.

RTO/ISO Discussion

MISO. The MISO market includes all of Wisconsin and portions of Michigan, Kentucky, Indiana, Illinois, Nebraska, Kansas, Missouri, Iowa, Minnesota, North Dakota, Montana and Manitoba, Canada.

The MISO energy market is designed to ensure that all market participants have open-access to the transmission system on a non-discriminatory basis. MISO, as an independent RTO, maintains functional control over the use of the transmission system to ensure transmission circuits do not exceed their secure operating limits and become overloaded. MISO operates day-ahead and real-time energy markets using a LMP system which calculates a price for every generator and load point within MISO. This market is transparent, allowing generators and load serving entities to see real-time price effects of transmission constraints and the impacts of congestion at each pricing point. MISO administers a centralized capacity market that relies on bilateral transactions for all sales and purchases beyond one month forward and includes a monthly voluntary clearing auction that allows buyers to clear residual capacity requirements.

MISO also administers an FTR market holding monthly and annual auctions. FTRs allow users to manage the cost of transmission congestion (as measured by LMP differentials, between source and sink points on the transmission grid) and corresponding price differentials across the market area.

MISO implemented the Ancillary Services Market (Regulation and Operating Reserves) on January 6, 2009 and implemented an enforceable Planning Reserve Margin for each planning year effective June 1, 2009. A feature of the Ancillary Services Market is the addition of scarcity pricing that, during supply shortages, can raise the combined price of energy and ancillary services significantly higher than the previous cap of $1,000/MWh.

An independent market monitor is responsible for ensuring that MISO markets are operating competitively and without exercise of market power.

Contracted Capacity and Energy

We commercialize our Coal segment assets through a combination of physical participation in the MISO markets (as described above), bilateral physical and financial power sales, and fuel and capacity contracts.

Reserve Margins

MISO's actual reserve margins tightened during summer 2011 with a record peak load of 103,621 MW on July 20, 2011. The actual average reserve margin for summer 2011 was 22 percent versus a MISO planning reserve margin of 17 percent. In 2010, the actual average reserve margin was 29 percent and the planning reserve margin was 15 percent.

Gas Segment

Our Gas segment is comprised of seven operating natural gas-fired power generation facilities located in California (2), Nevada (1), Illinois (1), Pennsylvania (1), New York (1), and Maine (1), and one fuel-oil fired power generation facility located in California, totaling 6,771 MW of electric generating capacity. Our 309 MW South Bay facility was permanently retired in 2010 and is currently in the process of being decommissioned. As previously mentioned, effective November 7, 2011, we deconsolidated DH, which indirectly owns all of our assets in the Gas segment, and began accounting for our investment in DH using the equity method of accounting. Please read Note 3 Chapter 11 Cases Accounting Impact for further discussion.

RTO/ISO Discussion

PJM. The PJM market includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Our Kendall and Ontelaunee facilities, located in Illinois and Pennsylvania, respectively, operate in PJM with an aggregate net generating capacity of 1,780 MW.

PJM administers markets for wholesale electricity and provides transmission planning for the region, utilizing the LMP system described above. PJM operates day-ahead and real-time markets into which generators can bid to provide electricity and ancillary services. PJM also administers markets for capacity. An independent market monitor continually monitors PJM markets for any exercise of market power or improper behavior by any entity. PJM implemented a forward capacity auction, the RPM, which established long-term markets for capacity in 2007. In addition to entering into bilateral capacity transactions, we have participated in RPM base residual auctions through PJM's planning year

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2014-2015, which ends May 31, 2015, as well as ongoing incremental auctions to balance positions and offer residual capacity that may become available.

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

NYISO. The NYISO market includes virtually the entire state of New York. Capacity pricing is calculated as a function of NYISO's annual required reserve margin, the estimated net cost of "new entrant" generation, estimated peak demand and the actual amount of capacity bid into the market at or below the demand curve. The demand curve mechanism provides for incrementally higher capacity pricing at lower reserve margins, such that "new entrant" economics become attractive as the reserve margin approaches required minimum levels. The intent of the demand curve mechanism is to ensure that existing generation facilities have enough revenue to recover their investment when capacity revenues are coupled with energy and ancillary service revenues. Additionally, the demand curve mechanism is intended to attract new investment in generation when and where that new capacity is needed most. To calculate the price and quantity of installed capacity, three ICAP demand curves are utilized: one for Long Island, one for New York City and one for Statewide (commonly referred to as Rest of State). Our Independence facility operates in the Rest of State market with an aggregate net generating capacity of 1,064 MW.

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

ISO-NE. The ISO-NE market includes the six New England states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. Much like regional zones in the NYISO, energy prices also vary among the participating states in ISO-NE, and are largely influenced by transmission constraints and fuel supply. ISO-NE implemented a FCM in June 2010, where capacity prices are determined through auctions. Our Casco Bay facility, located in Maine, operates in ISO-NE with an aggregate net generating capacity of 540 MW.

CAISO. CAISO covers approximately 90 percent of the State of California and operates a centrally cleared market for energy and ancillary services. Energy is priced at each location utilizing the LMP system described above. This market structure was implemented in April of 2009 as part of the MRTU. Currently the CAISO has a mandatory resource adequacy requirement but no centrally-administered capacity market. The Oakland facility has been designated as an RMR unit by the CAISO for 2012. Our Moss Landing, Morro Bay and Oakland facilities operate in CAISO with an aggregate net generating capacity of 3,344 MW.

Contracted Capacity and Energy

PJM. Our generation assets in PJM are natural gas-fired, combined-cycle, intermediate-dispatch facilities. We commercialize these assets through a combination of bilateral power, fuel and capacity contracts. We commercialize our capacity through either the RPM auction or on a bilateral basis. Our

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Kendall facility has two tolling agreements, one for 135 MW that expires in March 2012 and one for 85 MW that expires in 2017.

NYISO. At our Independence facility, 740 MW of capacity is contracted under a capacity sales agreement that runs through 2014. Revenue from this capacity obligation is largely fixed with a variable discount that varies each month based on the applicable LMP. Additionally, we supply steam and up to 44 MW of electric energy from our Independence facility to a third party at a fixed price.

Due to the standard capacity market operated by NYISO and liquid over-the-counter market for NYISO capacity products, we are able to sell substantially all of the Independence facility's remaining uncommitted capacity into the market.

ISO-NE. Five forward capacity auctions have been held to date with capacity clearing prices ranging from a high of $4.50 kW/month for the 2010/2011 market period to a low of $2.95 kW/month for the 2013/2014 market period. These capacity clearing prices represent the floor price; the actual rate paid to market participants was affected by pro-rationing due to oversupply conditions.

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

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

Reserve Margins

PJM. Actual reserve margins are approximately 11 percent above PJM's current required installed reserve margin of 15.5 percent. The reserve margin based on deliverable capacity was 27 percent for Planning Year 2011/12 as compared to 26 percent for Planning Year 2010/11. PJM's required installed reserve margin can change annually and is 15.5 percent for Planning Year 2011/12.

NYISO. A reserve margin of 16 percent has been accepted by FERC for the New York Control Area for the period beginning May 1, 2012 and ending April 30, 2013, up from the current requirement of 15.5 percent. The actual amount of installed capacity is approximately 14 percent above NYISO's current required margin.

ISO-NE. Recommended improvements and modifications to the FCM design are currently in litigation at FERC, and discussions to address improvements to the FCM design are currently underway by the ISO and its stakeholders.

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

The CPUC requires a Resources Adequacy margin of 15 to 17 percent. As of the latest Summer Assessment for 2011, reserve margin was approximately 20.8 percent. Unlike other centrally cleared capacity markets, the CAISO Resource Adequacy market is a bi-laterally traded market.

DNE Segment

Our DNE segment is comprised of the Roseton and Danskammer facilities located in Newburgh, New York, with a total capacity of 1,693 MW. A total of 1,570 MW of generation capacity relates to

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leased units at the two facilities. In connection with the Chapter 11 Cases, the Debtor Entities rejected these long-term leases. The Debtor Entities have remained in physical possession of and have continued to operate the leased facilities to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facilities is permitted to be transitioned. Please read Note 3 Chapter 11 Cases for further discussion.

Our Roseton and Danskammer facility sites are adjacent and share common resources such as fuel handling, a docking terminal, personnel and certain associated systems.

RTO/ISO Discussion

NYISO. For a full discussion of the NYISO market, see the "NYISO" section under "Gas RTO/ISO Discussion" above. Our DNE facilities operate in the Rest of State market. Due to transmission constraints, energy prices vary across New York and are generally higher in the Southeastern part of New York, where our Roseton and Danskammer facilities are located, and in New York City and Long Island.

Contracted Capacity and Energy

We commercialize these assets through a combination of bilateral physical and financial power, fuel and capacity contracts. Due to the standard capacity market operated by NYISO and liquid over-the-counter market for NYISO capacity products, we are able to sell substantially all of the assets' capacity into the market.

Other

Corporate governance roles and functions, which are managed on a consolidated basis, and specialized support functions such as finance, accounting, commercial, risk control, tax, legal, regulatory, human resources, administration and information technology, are allocated to each reportable segment, in accordance with the relevant Services Agreements. Please read Note 20 Related Party Transactions Service Agreements for further discussion. Corporate interest expense and income taxes are included in Other, as are corporate-related other income and expense items.

ENVIRONMENTAL MATTERS

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

Our aggregate expenditures (both capital and operating) for compliance with laws and regulations related to the protection of the environment were approximately $180 million in 2011 compared to approximately $225 million in 2010 and approximately $320 million in 2009. The 2011 expenditures included approximately $150 million for projects related to our Consent Decree (which is defined and discussed below) compared to approximately $200 million for Consent Decree projects in 2010. We estimate that total environmental expenditures in 2012 related to our Coal segment will be approximately $100 million, including approximately $75 million in capital expenditures and

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approximately $25 million in operating expenditures. In addition, we estimate that total environmental expenditures of DH, which includes our Gas and DNE segments, will be approximately $10 million in 2012, consisting only of operating expenditures. Changes in environmental regulations or outcomes of litigation and administrative proceedings could result in additional requirements that would necessitate increased future spending and could create adverse operating conditions. Please read Note 23 Commitments and Contingencies for further discussion of this matter.

The Clean Air Act

The CAA and comparable state laws and regulations relating to air emissions impose responsibilities on owners and operators of sources of air emissions, including requirements to obtain construction and operating permits as well as compliance certifications and reporting obligations. The CAA requires that fossil-fueled electric generating plants have sufficient emission allowances to cover actual SO_2 emissions and in some regions NO_X emissions, and that they meet certain pollutant emission standards as well. Our power generation facilities, some of which have changed their operations to accommodate new control equipment or changes in fuel mix, are currently in compliance with these requirements.

In order to ensure continued compliance with the CAA and related rules and regulations, including ozone-related requirements, we have installed, are in the process of installing, or have plans to install additional emission reduction technology at our Coal segment facilities. Two coal-fired units at our Baldwin facility and the coal-fired unit at our Havana facility have installed and are operating dry flue gas desulphurization systems for the control of SO_2 emissions, and electrostatic precipitators and baghouses for the control of particulate emissions. A third unit at Baldwin (Unit 2) currently utilizes an electrostatic precipitator and is scheduled to complete installation of a dry flue gas desulphurization system and baghouse by the end of 2012. Our coal-fired units at the Hennepin facility have electrostatic precipitators and baghouses for the control of particulate matter. The baghouses at our Coal segment facilities also control hazardous air pollutants in particulate form, such as most metals. Activated carbon injection or mercury oxidation systems for the control of mercury emissions have been installed and are operating on approximately 97 percent of our Coal segment's coal-fired capacity, and we will install controls on our final unit (Wood River Unit 4) by 2013. SCR technology to control NO_X emissions has been installed and has been operating at Baldwin Units 1 and 2 and at Havana for several years; the remaining Coal segment units use low-NO_X burners and overfire air to lower NO_X emissions.

Multi-Pollutant Air Emission Initiatives

In recent years, various federal and state legislative and regulatory multi-pollutant initiatives have been introduced. In 2005, the EPA finalized the CAIR, which would require reductions of approximately 70 percent each in emissions of SO_2 and NO_x by 2015 from coal-fired power generation units across the eastern United States. The CAIR was challenged by several parties and ultimately remanded to the EPA by the U.S. Court of Appeals for the District of Columbia Circuit. The CAIR remained in effect in 2011 and, as a result of a court order staying the CAIR's intended replacement rule (i.e. the CSAPR), the CAIR will continue in effect in 2012 at least until the judicial challenges to the CSAPR are decided. Our facilities in Illinois and New York are subject to state SO_2 and NO_x limitations more stringent than those imposed by the CAIR.

Cross-State Air Pollution Rule. On July 6, 2011, the EPA issued its final rule on Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (the "Cross-State Air Pollution Rule," formerly known as the Transport Rule). Numerous petitions for judicial review of the CSAPR were filed and, on December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued an order staying implementation of the CSAPR. The court is scheduled to hear oral argument in the CSAPR appeals in April 2012. We cannot predict with

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confidence the outcome of the litigation at this time. The EPA has reinstated the CAIR pending judicial review of the CSAPR.

The CSAPR is intended to reduce emissions of SO_2 and NO_x from large EGUs in the eastern half of the United States. If the court lifts the stay and upholds the CSAPR, the rule would impose cap-and-trade programs within each affected state that cap emissions of SO_2 and NO_x at levels predicted to eliminate that state's contribution to nonattainment in, or interference with maintenance of attainment status by, down-wind areas with respect to the NAAQS for particulate matter ($PM_{2.5}$) and ozone. The rule would be implemented initially through federal implementation plans. Our generating facilities in Illinois, New York and Pennsylvania would be subject to the rule.

Under the CSAPR, Illinois, New York and Pennsylvania would be subject to new cap-and-trade programs capping emissions of NO_x from May 1 through September 30 and capping emissions of SO_2 and NO_X on an annual basis. Requirements applicable to NO_x emissions would have required compliance with the annual NO_x reductions beginning January 1, 2012 and ozone season NO_x reductions beginning May 1, 2012. The requirements applicable to SO_2 emissions from electric generating units in Illinois, New York and Pennsylvania would have been implemented in two stages with compliance dates of January 1, 2012 and January 1, 2014. The SO_2 emission budgets would be reduced in 2014, and existing EGUs in these states would be allocated fewer SO_2 emission allowances beginning in 2014. States submitting a SIP to achieve the required reductions in place of the federal implementation plan would be allowed to use different allowance allocation methodologies beginning with vintage year 2013.

Electric generating units would be required to hold one emission allowance for every ton of SO_2 and/or NO_x 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 controls more often, (iii) switching fuels, or (iv) curtailing or ceasing operation. Allowance trading is generally allowed under the CSAPR among sources within the same state with limited interstate allowance trading. On February 6, 2012, the EPA issued technical revisions to the CSAPR, including a two-year delay in the assurance penalty provisions that is intended to promote liquidity in the CSAPR allowance markets and a smooth transition from the CAIR programs. Although the CSAPR is stayed pending judicial review, the EPA is moving forward with revisions to the CSAPR so that the EPA can implement the CSAPR if the stay is lifted.

Based on the allowance allocations in the final CSAPR and our current projections of emissions in 2012, we anticipate that our Coal segment facilities would have an adequate number of allowances in 2012 under each of the three applicable CSAPR cap-and-trade programs (SO_2, NO_x annual, and NO_x ozone season). For our Danskammer and Roseton facilities, we anticipate a shortfall of allocated allowances in 2012 under each of the three CSAPR programs.

Legislation also has been introduced in Congress that, if enacted, would void or delay the implementation of the CSAPR. However, the Obama Administration has indicated that it would veto any bill that would delay or void the CSAPR. Similar legislative efforts are expected to continue in 2012 but passage of such legislation in the next year is considered unlikely.

We will continue to monitor rulemaking, judicial and legislative developments regarding the CASPR, and evaluate any potential impacts on our operations.

Mercury/HAPs. In March 2005, the EPA issued the CAMR for control of mercury emissions from coal-fired power plants and established a cap-and-trade program requiring states to promulgate rules at least as stringent as the CAMR. In December 2006, the Illinois Pollution Control Board approved a state rule for the control of mercury emissions from coal-fired power plants that required additional capital and operating expenditures at our Illinois coal-fired plants beginning in 2007. The State of New York has also approved a mercury rule that will likely require us to incur additional capital and

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operating costs for the coal-fired units at our Danskammer power generating facility by January 1, 2015. In connection with the Chapter 11 Cases, the Debtor Entities rejected the lease at Danskammer. The Debtor Entities have remained in physical possession of and have continued to operate the leased facility to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facility is permitted to be transitioned. Please read Note 3 Chapter 11 Cases for further discussion.

In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAMR; however, the Illinois and New York mercury regulations remain in effect. In March 2011, the EPA released a proposed rule to establish MACT emission standards for HAPs at coal- and oil-fired EGUs. On December 21, 2011, the EPA issued its EGU MACT final rule, which establishes numeric emission limits for mercury, non-mercury metals (filterable particulate may be used as a surrogate), and acid gases (hydrogen chloride used as a surrogate, with SO_2 as an optional surrogate for coal-fired units using flue gas desulfurization; oil-fired units also would be subject to a hydrogen fluoride limit), and work practice standards for organic HAPs. Compliance would be required by April 16, 2015 (i.e. three years after the effective date of the final rule), unless an extension is granted in accordance with the CAA.

Given the air emission controls already employed or planned for installation on our Coal segment facilities, we expect that our coal units in Illinois will be in compliance with the EGU MACT emission limits without the need for significant additional investment. We continue to evaluate the final EGU MACT rule, as well as related judicial and legislative developments, for potential impacts on our operations.

Visibility. The CAVR requires states to include BART requirements for individual facilities in their SIPs to address regional haze. The requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. States are required to submit regional haze implementation plans to the EPA detailing their plans to reduce emissions of visibility-impairing pollutants (NO_x, SO_2 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 Baldwin and Roseton facilities and Unit 4 at our Danskammer facility have been identified as BART-eligible facilities. At Baldwin, BART would be met through compliance with the Illinois Multi-Pollutant Standards currently in effect. In compliance with the New York State BART Rule, our Danskammer and Roseton power generating facilities performed a comprehensive, unit-specific modeling analysis for their BART eligible units to determine their impact on visibility. In the fall of 2010, we submitted this analysis to NYSDEC along with a proposal to reduce NO_x and SO_2 emission limits to address impacts on visibility. As approved by NYSDEC in a Title V permit modification issued in November 2011, BART compliance at our Roseton facility would be achieved, effective January 1, 2014, by reducing the sulfur content of our fuel oil and optimization of existing NO_x emission controls. In November 2011, NYSDEC issued for public comment a proposed modified Title V permit for Danskammer, which would require the BART emission limits for Unit 4 be achieved, effective July 1, 2014, through optimization of existing NO_x emission controls, co-firing with natural gas, use of alternative coal, and/or installation of additional emission controls. We are continuing to review our compliance options at Danskammer Unit 4, options which could result in significant expenditures for emission control equipment or a switch to natural gas. In connection with the Chapter 11 Cases, the Debtor Entities rejected the leases at the Danskammer and Roseton facilities. The Debtor Entities have remained in physical possession of and have continued to operate the leased facilities to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facilities is permitted to be transitioned. Please read Note 3 Chapter 11 Cases for further discussion.

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Other Air Emission Initiatives

New York NO_x RACT Rule. In June 2010, New York State issued a final rule establishing revised RACT limits for emissions of NO_x from stationary combustion sources. Compliance with the revised NO_x RACT limits is required by July 1, 2014, and compliance plans were due to NYSDEC by January 1, 2012. Compliance options include meeting presumptive RACT limits, case-by-case RACT determinations, fuel switching during the ozone season (May 1 through September 30), and participation in a system averaging plan. In December 2011, we submitted RACT proposals for our Gas segment's Independence facility and DNE segment's Danskammer and Roseton facilities. For our Independence facility, we proposed to meet the presumptive RACT limits using the facility's existing SCR technology and currently applicable NO_x BACT emission limits. For each of our DNE segment facilities, we proposed to meet the presumptive RACT limits with compliance to be achieved by a system averaging plan. We are continuing to review our NO_x RACT compliance options at Roseton and Danskammer. In connection with the Chapter 11 Cases, the Debtor Entities rejected the leases at the Danskammer and Roseton facilities. The Debtor Entities have remained in physical possession of and have continued to operate the leased facilities to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facilities is permitted to be transitioned. Please read Note 3 Chapter 11 Cases for further discussion.

Consent Decree. In 2005, we settled a lawsuit filed by the EPA and the U.S. Department of Justice that alleged violations of the CAA and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating facility. A consent decree was finalized in July 2005 that would prohibit operation of certain of our power generating facilities after certain dates unless specified emission control equipment is installed (the "Consent Decree"). We have achieved all emission reductions scheduled to date under the Consent Decree. As of December 31, 2011, only Baldwin Unit 2 has material outstanding Consent Decree work yet to be performed, which is scheduled for completion by the end of 2012. We expect our costs associated with the remaining Consent Decree projects to be approximately $71 million and $5 million in 2012 and 2013, respectively. This estimate includes a number of assumptions about uncertainties beyond our control, such as costs associated with labor and materials.

Please read Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources for further discussion.

Information Request under Section 114 of the Clean Air Act. In March 2009, we received an information request from the EPA regarding maintenance, repair and replacement projects undertaken between January 2000 and the present at the Danskammer power generation facility. The information request is related to a nationwide enforcement initiative by the EPA targeting coal-fired power plants. We submitted responses to the information request in April and July 2009. While we have not since received any further communication from the EPA on this matter, the EPA enforcement initiative against coal-fired power plants remains ongoing. The EPA's inquiry may lead to claims of CAA violations that could result in an enforcement action, the scope of which cannot be predicted with confidence at this time. In connection with the Chapter 11 Cases, the Debtor Entities rejected the lease at the Danskammer facility. The Debtor Entities have remained in physical possession of and have continued to operate the leased facility to the extent necessary to comply with applicable federal and state regulatory requirements. As we intend to transfer operational control of the leased facility to a third party, we do not anticipate that any such enforcement action will have a material adverse effect on our financial condition, results of operations and cash flows.

SO_2 1-hour NAAQS. In June 2010, the EPA adopted a new SO_2 NAAQS, replacing the previous 24-hour and annual standards with a new short-term 1-hour standard. By June 2011, each state was to submit to the EPA recommended designations identifying the compliance status of each area in the state with the new 1-hour SO_2 NAAQS. The EPA is required to promulgate final area designations for

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the 1-hour SO_2 NAAQS in June 2012. States with designated nonattainment areas must submit SIP revisions for those areas within 18 months from the effective date of the designation (approximately February 2014), and areas initially designated nonattainment must achieve attainment no later than five years after intial designation (approximately August 2017).

In June 2011, the Illinois EPA recommended a nonattainment designation for the area where our Wood River power generating station is located. Our Wood River facility is one of several major SO_2 emissions sources in the larger area. The NYSDEC recommended that all areas in New York State be designated attainment or unclassifiable; however, in November 2011, the Sierra Club recommended to the NYSDEC and the EPA that, based on emissions modeling it had performed, certain areas in New York State be designated nonattainment due to SO_2 emissions from the Danskammer generating station. While the nature and scope of potential future requirements concerning the 1-hour SO_2 NAAQS cannot be predicted with confidence at this time, a requirement for additional SO_2 emission reductions at our Wood River or Danskammer facilities, or any of our other facilities, for purposes of the 1-hour SO_2 NAAQS may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

The Clean Water Act

Our water withdrawals and wastewater discharges are permitted under the CWA and analogous state laws. The cooling water intake structures at several of our facilities are regulated under Section 316(b) of the CWA. This provision generally directs that standards set for facilities require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact. These standards are developed and implemented for power generating facilities through NPDES permits or SPDES permits. Historically, standards for minimizing adverse environmental impacts of cooling water intakes have been made by permitting agencies on a case-by-case basis considering the best professional judgment of the permitting agency.

In 2004, the EPA issued the Cooling Water Intake Structures Phase II Rules (the "Phase II Rules"), which set forth standards to implement the BTA requirements for cooling water intakes at existing facilities. The rules were challenged by several environmental groups and in 2007 were struck down by the U.S. Court of Appeals for the Second Circuit in *Riverkeeper, Inc. v. EPA*. The court's decision remanded several provisions of the rules to the EPA for further rulemaking. Several parties sought review of the decision before the U.S. Supreme Court. In April 2009, the U.S. Supreme Court ruled that the EPA permissibly relied on cost-benefit analysis in setting the national BTA performance standard and in providing for cost-benefit variances from those standards as part of the Phase II Rules.

In July 2007, following remand of the rules by the U.S. Court of Appeals, the EPA suspended its Phase II Rules and advised that permit requirements for cooling water intake structures at existing facilities should once more be established on a case-by-case best professional judgment basis until replacement rules are issued. On March 28, 2011, the EPA released a proposed rule for cooling water intake structures at existing facilities. The proposed rule would (i) establish impingement mortality standards that would give affected facilities the option of either achieving impingement mortality of no more than 12 percent (annual average) and 31 percent (monthly average) or maintaining intake velocity at no more than 0.5 feet per second under all conditions; and (ii) require the permitting authority to establish case-by-case entrainment mortality standards based on a site-specific assessment of technology feasibility and performance, energy and environmental impacts, benefits, social costs, and other factors. We continue to analyze the proposed rule and its potential impacts at our affected power generation facilities. Under a settlement agreement, the EPA will finalize the rule in July 2012. The scope of requirements, timing for compliance and the compliance methodologies that will ultimately be allowed under the final rule potentially may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

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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 (Danskammer, Roseton and Moss Landing) have been challenged on this basis. The Danskammer SPDES permit, which was renewed and issued in June 2006, does not require installation of a closed cycle cooling system; however, it does require aquatic organism mortality reductions resulting from NYSDEC's determination of BTA requirements under its regulations. All appeals of this permit have been exhausted. The Moss Landing NPDES permit, which was issued in 2000, does not require closed cycle cooling and was challenged by a local environmental group. In August 2011, the Supreme Court of California affirmed the appellate court's decision upholding the permit. One permit challenge is 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. In October 2006, various holdings in the administrative law judge's ruling admitting the environmental group petitioners to party status and setting forth the issues to be adjudicated in the permit renewal hearing were appealed to the Commissioner of NYSDEC by the petitioners, NYSDEC staff and us. The permit renewal hearing will be scheduled after the Commissioner rules on those appeals. We believe that the petitioners' claims lack merit and we have opposed those claims vigorously. In connection with the Chapter 11 Cases, the Debtor Entities rejected the leases at Roseton and Danskammer. The Debtor Entities have remained in physical possession of and have continued to operate the leased facilities to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facilities is permitted to be transitioned. Please read Note 3 Chapter 11 Cases for further discussion.

Other future NPDES or SPDES proceedings could have a material effect on our financial condition, results of operations and cash flows; however, given the numerous variables and factors involved in calculating the potential costs associated with installing a closed cycle cooling system, any decision to install such a system at any of our facilities would be made on a case-by-case basis considering all relevant factors at such time. If capital expenditures related to cooling water systems are great enough to render the operation of the plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate that facility and forego the capital expenditures.

California Water Intake Policy. The California State Water Board adopted its Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (the "Policy") in May 2010. The Policy requires 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 would be required at our Morro Bay power generation facility by December 31, 2015 and at our Moss Landing power generation facility by December 31, 2017. On October 27, 2010, Dynegy Morro Bay, LLC and Dynegy Moss Landing, LLC joined with other California power plant owners in filing a lawsuit in the Sacramento County Superior Court challenging the Policy. We cannot predict with confidence the outcome of the litigation at this time.

In September 2010, the State Water Board proposed to amend the Policy to allow an owner or operator of a power plant with previously installed combined-cycle power generating units to continue to use once-through cooling at combined-cycle units until the unit reaches the end of its useful life under certain circumstances. At its December 14, 2010, hearing on the proposed amendment, the State Water Board declined to approve the amendment and instead tabled it for consideration until after the

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Statewide Advisory Committee on Cooling Water Intake Structures has reviewed facility compliance plans and made recommendations to the Board, which is expected to occur in spring 2012.

In accordance with the Policy, on April 1, 2011, we submitted proposed compliance plans for our Morro Bay and Moss Landing facilities. For Morro Bay and Moss Landing Units 6 and 7, we proposed to continue our ongoing review of potential compliance options taking into account the facility's applicable final compliance deadline. For Moss Landing Units 1 and 2, we proposed to continue current once-through cooling operations through the end of 2032, at which time we would evaluate repowering or installation of feasible control measures.

It may not be possible to meet the requirements of the Policy without installing closed cycle cooling systems. 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. In addition, while the Policy is generally at least as stringent as the EPA's proposed rule for cooling water intake structures, compliance with the Policy may not meet all requirements of the forthcoming EPA final rule. If capital expenditure requirements related to cooling water systems are 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.

New York Water Intake Policy. On July 10, 2011, the NYSDEC issued its final policy on BTA for Cooling Water Intake Structures (the "NYSDEC Policy"). The NYSDEC Policy establishes wet closed-cycle cooling or its equivalent (i.e. reductions in impingement mortality and entrainment from calculation baseline that are 90 percent or greater of that which would be achieved by wet closed-cycle cooling) as the performance goal for existing power plants. The NYSDEC Policy exempts existing power generation facilities operated at less than 15 percent of capacity over a current five-year averaging period from the entrainment performance goal, provided that the facility is operated in a manner that minimizes the potential for entrainment. For these low-capacity facilities, NYSDEC will determine site-specific performance goals for entrainment on a best professional judgment basis. For facilities for which a BTA determination was issued prior to adoption of the policy and which are in compliance with an existing BTA compliance schedule and verification monitoring, the NYSDEC Policy does not apply unless and until the results of verification monitoring demonstrate the necessity of more stringent BTA requirements. At this time we do not believe that the NYSDEC Policy will have a material impact on operations of the subject DNE segment facilities given the prior BTA determination for Danskammer and the entrainment exemption for low-capacity facilities.

Other CWA Initiatives. The requirements applicable to water quality are expected to increase in the future. A number of efforts are under way within the EPA to evaluate water quality criteria for parameters associated with the by-products of fossil fuel combustion. These parameters relate primarily to arsenic, mercury and selenium. Under a consent decree, the EPA is required to propose revisions to the Effluent Guidelines for steam electric units by July 23, 2012 and to take final action on the proposal by January 31, 2014. Significant changes in these requirements could require installation of additional water treatment equipment at our facilities or require dry handling of coal ash. The nature and scope of potential future water quality requirements concerning the by-products of fossil fuel combustion cannot be predicted with confidence at this time, but could have a material adverse effect on our financial condition, results of operations and cash flows.

Coal Combustion Residuals

The combustion of coal to generate electric power creates large quantities of ash that are managed at power generation facilities in dry form in landfills and in liquid or slurry form in surface impoundments. Each of our coal-fired plants has at least one CCR management unit. At present, CCR is regulated by the states as solid waste. The EPA has considered whether CCR should be regulated as

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a hazardous waste on two separate occasions, including most recently in 2000, and both times has declined to do so. The December 2008 failure of a CCR surface impoundment dike at the Tennessee Valley Authority's Kingston Plant in Tennessee accompanied by a very large release of ash slurry has resulted in renewed scrutiny of CCR management.

In response to the Kingston ash slurry release, the EPA initiated an investigation of the structural integrity of certain CCR surface impoundment dams including those at our Coal segment facilities. We responded to EPA requests for information, and our surface impoundment dams that the EPA has assessed to date were found to be in satisfactory condition with no recommendations.

In addition, on June 21, 2010, the EPA proposed two alternative rules under RCRA for federal regulation of the management and disposal of CCR from electric utilities and independent power producers. One proposal would regulate CCR as a special waste under RCRA 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. While certain types of beneficial use of CCR would be exempt from regulation under the subtitle C proposal, the impact of subtitle C regulation on the continued viability of beneficial use is debated. Regulation under subtitle C would effectively phase out the use of ash ponds for disposal of CCR.

The 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.

Certain environmental organizations have advocated designation of CCR as a hazardous waste; however, many state environmental agencies have expressed strong opposition to such designation. On September 30, 2011, the EPA released a notice of data availability ("NODA") regarding its CCR proposed rule for the limited purpose of soliciting comment on additional information regarding the CCR proposal as identified in the NODA. The EPA is not expected to issue final regulations governing CCR management until late 2012 or thereafter.

Federal legislation to address CCR also has been introduced in Congress. On October 14, 2011, the House of Representatives passed H.R. 2273, the Coal Residuals Reuse and Management Act, which would authorize the states to implement a subtitle D permit program for CCR disposal units. The permit requirements would include structural integrity standards and certain elements of the subtitle D criteria for municipal solid waste landfills, including location restrictions, design standards, ground water monitoring, financial assurance, corrective action, closure and post-closure care. The EPA would be authorized to administer and enforce the subtitle D criteria for CCR disposal units only if a state chooses not to do so or if the EPA finds that the state program is deficient. A companion bill, S.1751, has been introduced in the Senate. We will continue to monitor CCR rulemaking and legislative developments and to evaluate any potential impacts on our operations.

We have implemented groundwater monitoring plans for the CCR surface impoundments at our Vermilion and Baldwin facilities in response to requests by the Illinois EPA. Groundwater monitoring results indicate that the CCR surface impoundments at each site impact onsite groundwater. At the request of the Illinois EPA, we have also initiated an investigation at the Baldwin facility to determine if the facility's CCR surface impoundment impacts offsite groundwater. We anticipate that results of this investigation will be available by mid-2012. If offsite groundwater impacts are identified and remediation measures are necessary in the future, we may incur significant costs that could have a material adverse effect on our financial condition and cash flows. At this time we cannot reasonably estimate the costs of corrective action that ultimately may be required at Baldwin. In addition, we have agreed to submit to the Illinois EPA by April 1, 2012 a proposed corrective action plan for certain

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CCR surface impoundments at the Vermilion facility. At this time we cannot reasonably estimate the costs of corrective action that ultimately may be required at Vermilion. Please read Note 23-Commitments and Contingencies for further discussion of Baldwin and Vermilion. Asset retirement costs are recorded for the estimated costs of closing CCR surface impoundments at each Coal segment facility.

The nature and scope of potential future requirements for CCR cannot be predicted with confidence at this time, but, as mentioned above, could have a material adverse effect on our financial condition, results of operations and cash flows. Further, public perceptions of new regulations regarding the reuse of coal ash may limit or eliminate the market that currently exists for coal ash reuse, which could have material adverse effects on our financial condition, results of operations and cash flows.

Climate Change

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

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

Power generating facilities are a major source of GHG emissions in 2011, our Coal, Gas and DNE segment facilities emitted approximately 24.1 million, 5.3 million and 1.3 million tons of CO_2e, respectively. The amounts of CO_2e emitted from our facilities during any time period will depend upon their dispatch rates during the period.

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

Federal Legislation Regarding Greenhouse Gases. Several bills have been introduced in Congress since 2003 that if passed would compel reductions in CO_2 emissions from power plants. Many of these bills have included cap-and-trade programs. However, with the political shift in the makeup of the 112th Congress (2011-2012), recently introduced legislation would instead either delay or prevent the EPA from regulating GHGs under the CAA. The passage of comprehensive GHG legislation in the next year is considered unlikely.

Federal Regulation of Greenhouse Gases. In April 2007, the U.S. Supreme Court issued its decision in *Massachusetts v. EPA*, holding that GHGs meet the definition of a pollutant under the CAA and that regulation of GHG emissions is authorized by the CAA.

In response to that decision, the EPA issued a finding in December 2009 that GHG emissions from motor vehicles cause or contribute to air pollution that endangers the public health and welfare. The endangerment finding, including the EPA's denial of subsequent requests for reconsideration have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The court has scheduled oral argument on the endangerment finding, as well as two related appeals concerning other EPA GHG rulemakings, for late February 2012. We cannot predict with confidence the outcome of the litigation.

The EPA has finalized several rules concerning GHGs as directly relevant to our facilities. In January 2010, the EPA rule on mandatory reporting of GHG emissions from all sectors of the economy went into effect and requires the annual reporting of GHG emissions. We have implemented processes and procedures to report these emissions and, as required, reported our 2010 GHG emissions by September 30, 2011.

The EPA Tailoring Rule, which became effective in January 2011, phases in new GHG emissions applicability thresholds for the PSD permit program and for the operating permit program under Title V of the CAA. In general, the Tailoring Rule establishes a GHG emissions PSD applicability threshold at a net increase of 75,000 tons per year of CO_2e for new and modified major sources. The Rule has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit and is scheduled for oral argument in coordination with the endangerment finding appeals. Application of the PSD program to GHG emissions will require implementation of BACT for new and modified major sources of GHG. In November 2010, the EPA issued its PSD and Title V Permitting Guidance for Greenhouse Gases. For coal-fired electric generating units, the guidance focuses on steam turbine and boiler efficiency improvements as a reasonable BACT requirement.

In addition, in March 2011, the EPA entered a settlement agreement of a CAA citizen suit under which the agency would propose NSPS under the CAA for control of GHG emissions from new and modified EGUs, as well as proposed emission guidelines for control of GHG emissions from existing EGUs. The lawsuit, *New York, et al. v. EPA,* involves a challenge to the NSPS for EGUs, issued in 2006, because the rule did not establish standards for GHG emissions. The settlement, as amended, required the EPA to issue proposed GHG emissions standards for EGUs by September 30, 2011 and to finalize the standards by May 26, 2012. In September 2011, the EPA announced that it would delay the release of the proposed GHG standards. The EPA is expected to issue proposed GHG NSPS for new and modified EGUs in spring 2012 but has not yet announced a schedule for proposing GHG emissions standards for existing EGUs.

State Regulation of Greenhouse Gases. Many states where we operate generation facilities have, are considering, or are in some stage of implementing, state-only regulatory programs intended to reduce emissions of GHGs from stationary sources as a means of addressing climate change.

Our assets in Illinois may become subject to a regional GHG cap-and-trade program under the MGGA. The MGGA is an agreement among six states and one Canadian province to create the MGGRP to establish GHG reduction targets and timeframes consistent with member states' targets and to develop a market-based and multi-sector cap-and-trade mechanism to achieve the GHG reduction targets. Illinois has set a goal of reducing GHG emissions to 1990 levels by the year 2020,

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and to 60 percent below 1990 levels by 2050. The MGGA advisory group released a model rule in 2010, but implementation by the MGGA participants has not moved forward.

Our assets in California are subject to the California Global Warming Solutions Act ("AB 32"), which became effective in January 2007. AB 32 requires the CARB to develop a GHG emission control program that will reduce emissions of GHG in the state to their 1990 levels by 2020. In October 2011, the CARB adopted its final GHG cap-and-trade regulation. The cap-and-trade program became effective on January 1, 2012, but cap-and-trade compliance obligations do not begin until January 1, 2013 due to litigation. The emissions cap set by the CARB for 2013 is about two percent below the emissions level forecast for 2012, declines in 2014 by about two percent, and by about three percent annually from 2015 to 2020. Additional rule changes on select issues will be considered in 2012. The CARB's first allowance auction is scheduled for August 2012. Under our current tolling agreements for Morro Bay and Moss Landing Units 6 and 7, our financial exposure is partially offset by our tolling arrangements that contain pass-through provisions for the cost of carbon allowances. For Moss Landing Units 1 and 2, we currently face financial exposure for any needed carbon allowances. We will manage that exposure as we begin to initiate hedge positions for 2013 and beyond. We will continue to monitor the CARB's cap-and-trade program rulemaking activities and evaluate any potential impacts on our operations.

The State of California is also a party to a regional GHG cap-and-trade program being developed under the WCI to reduce GHG emissions in the participating jurisdictions. The WCI started as a collaborative effort among seven states and four Canadian provinces, but California currently is the sole remaining state participant. California's implementation of AB 32 is expected to constitute the state's contribution to the WCI. The WCI anticipates linking partner cap-and-trade programs in 2012, which may require the consideration of additional rule changes.

On January 1, 2009, our assets in New York and Maine became subject to a state-driven GHG emission control program known as RGGI. RGGI was developed and initially implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states implemented rules regulating GHG emissions using a cap-and-trade program to reduce CO_2 emissions by at least 10 percent of 2009 emission levels by the year 2018. Compliance with the allowance requirement under the RGGI cap-and-trade program can be achieved by reducing emissions, purchasing or trading allowances, or securing offset allowances from an approved offset project. While allowances are sold by year, actual compliance is measured across a three-year control period. The first control period covered 2009-2011. The second control period covers 2012-2014.

In December 2011, RGGI held its fourteenth auction, in which approximately 27.29 million allowances for the first control period were sold at clearing prices of $1.89 per allowance. No bids were submitted for allowances for a future control period. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure some allowances for our affected assets. RGGI plans to continue to conduct quarterly auctions in 2012 but will offer only 2012 allocation year allowances in those auctions. RGGI also will perform a comprehensive program review in 2012, including an evaluation of a possible additional reduction in the CO_2 emissions cap. The outcome of that program review and its potential impact on our affected assets are currently unknown.

DH's generating facilities in New York and Maine emitted approximately 3.5 million tons of CO_2 during 2011. For the first RGGI compliance period (2009-2011), the actual cost of allowances required for our operations was $35 million. The average clearing price for future period allowances sold in all auctions held to date is $2.33. We believe that the current market price of $1.96 is indicative of future pricing and estimate DH's cost of allowances required to operate these facilities during 2012 would be approximately $7 million.

In August 2011, the State of New York enacted the "Power NY Act of 2011," which requires the NYSDEC to promulgate within 12 months regulations targeting CO_2 emission reductions from major

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electric generating facilities that commenced construction after the effective date of the regulations. In January 2012, NYSDEC issued proposed CO_2 emission standards for new major electric generating facilities and for increases in capacity of at least 25 MW at existing major electric generating facilities. The proposal would not affect existing electric generating facilities that do not expand electrical output capacity.

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

In September 2009, the U.S. Court of Appeals for the Second Circuit considered the appeal of *Connecticut v. AEP* and held that the U.S. District Court is an appropriate forum for resolving claims by eight states and New York City against six electric power generators related to climate change. Similarly, in October 2009, the U.S. Court of Appeals for the Fifth Circuit considered the appeal of *Comer v. Murphy Oil* and held that claims related to climate change by property owners along the Mississippi Gulf Coast against energy companies could be resolved by the courts. However, the *Comer v. Murphy* decision was subsequently vacated. In September 2009, the U.S. District Court for the Northern District of California dismissed claims related to climate change by an Alaskan community against 24 companies in the energy industry, including DH, in *Native Village of Kivalina and City of Kivalina v. ExxonMobil Corporation, et al.* The Kivalina case is pending before the U.S. Court of Appeals for the Ninth Circuit. However, on February 2, 2012, the parties filed a joint motion to dismiss with prejudice DH as a defendant in the case due to the bankruptcy petition filed by DH in the Chapter 11 Cases. On June 20, 2011, the U.S. Supreme Court issued its decision in *AEP v. Connecticut,* which reviewed the appellate court decision in *Connecticut v. AEP.* The Supreme Court was equally divided by a vote of 4-4 on the question of whether the plaintiffs had standing to bring the suit and, therefore, affirmed the court's exercise of jurisdiction. On the merits the Court ruled by a vote of 8-0 that the CAA and EPA action authorized by the CAA displace any federal common law right to seek abatement of CO_2 emissions from fossil fuel-fired power plants. The Court did not reach the issue of whether the CAA preempts similar claims under state nuisance law.

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

Carbon Initiatives. We participate in several programs that partially offset or mitigate our GHG emissions. In the lower Mississippi River Valley, we have partnered with the U.S. Fish & Wildlife Service to restore more than 45,000 acres of hardwood forests by planting more than 8 million bottomland hardwood seedlings. In Illinois, we are funding prairie, bottomland hardwood and savannah restoration projects in partnership with the Illinois Conservation Foundation. We also have programs to reuse CCR produced at our coal-fired generation units through agreements with cement manufacturers that incorporate the material into cement products, helping to reduce CO_2 emissions from the cement manufacturing process.

Remedial Laws

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

As a result of their age, a number of our facilities contain quantities of asbestos-containing materials, lead-based paint and/or other regulated materials. Existing state and federal rules require the proper management and disposal of these materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations and removal and abatement of asbestos-containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself.

COMPETITION

Demand for power may be met by generation capacity based on several competing generation technologies, such as natural gas-fired, coal-fired or nuclear generation, as well as power generating facilities fueled by alternative energy sources, including hydro power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Our Coal, Gas and DNE power generation businesses compete with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies and financial institutions. We believe that our ability to compete effectively in the power generation business will be driven in large part by our ability to achieve and maintain a low cost of production, primarily by managing fuel costs and to provide reliable service to our customers. Our ability to compete effectively will also be impacted by various governmental and regulatory activities designed to reduce GHG emissions. For example, regulatory requirements for load-serving entities to acquire a percentage of their energy from renewable-fueled facilities will potentially reduce the demand for energy from gas-fired facilities such as those we own and operate. We believe our primary competitors consist of at least 20 companies in the power generation business.

SIGNIFICANT CUSTOMERS

For the year ended December 31, 2011, approximately 41 percent, 16 percent and 20 percent of our consolidated revenues were derived from transactions with MISO, NYISO and PJM, respectively. For the year ended December 31, 2010, approximately 30 percent, 15 percent and 13 percent of our consolidated revenues were derived from transactions with MISO, NYISO and PJM, respectively. For the year ended December 31, 2009, approximately 19 percent, 12 percent and 11 percent of our consolidated revenues were derived from transactions with MISO, NYISO and PJM, respectively. No other customer accounted for more than 10 percent of our consolidated revenues during 2011, 2010 or 2009.

EMPLOYEES

At December 31, 2011, we and DH had approximately 274 employees at our corporate headquarters and approximately 988 employees at our facilities, including field-based administrative employees. Approximately 639 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions. Approximately 770 of our employees, including those located in our corporate headquarters, our coal facilities and our natural gas facilities, are employed by a subsidiary of DH, and approximately 147 of our employees are employed by the Debtor Entities. We believe relations with our employees are satisfactory.

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Item 1A. ***Risk Factors***

FORWARD-LOOKING STATEMENTS

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

- our ability to obtain approval of the Bankruptcy Court with respect to the Debtor Entities' motions in the Chapter 11 Cases and to develop, prosecute, confirm and consummate one or more plans of reorganization with respect to the Chapter 11 Cases, including the Plan, and to consummate all the transactions contemplated by the Noteholder Restructuring Support Agreement;

- our ability to transfer the operations associated with Roseton and Danskammer facilities to one or more third parties in connection with the rejection of the related leases under the Chapter 11 Cases;

- beliefs and assumptions relating to our liquidity, available borrowing capacity and capital resources generally, 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;

- the anticipated effectiveness of the overall restructuring activities and any additional strategies to address our liquidity and our capital resources including accessing the capital markets;

- limitations on our ability to utilize previously incurred federal net operating losses or alternative minimum tax credits;

- beliefs that control over DH and its consolidated subsidiaries will likely revert to Dynegy upon emergence of DH from bankruptcy with Dynegy assuming the obligations of DH, resulting in reconsolidation;

- expectations regarding our compliance with our New Credit Agreements, including collateral demands, interest expense and other payments;

- the timing and anticipated benefits to be achieved through our company-wide cost savings programs, including our PRIDE initiative;

- 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, assumptions and projections regarding the demand for power, generation volumes and commodity pricing, including natural gas prices and the impact on such prices from shale gas proliferation and the timing of a recovery in natural gas prices, if any;

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- 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;
- beliefs and assumptions regarding our ability to enhance or protect 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, our focus on safety and our ability to efficiently operate our assets so as to capture revenue generating opportunities and operating margins;
- beliefs about the outcome of legal, regulatory, administrative and legislative matters; and
- expectations regarding performance standards and estimates regarding capital and maintenance expenditures, including the Consent Decree and its associated costs and performance standards.

Any or all of our forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors, many of which are beyond our control, including those set forth below.

FACTORS THAT MAY AFFECT FUTURE RESULTS

Risks Related to Restructuring

The Debtor Entities filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code and are subject to the risks and uncertainties associated with bankruptcy cases.

The Debtor Entities filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. For the duration of the Debtor Entities' Chapter 11 Cases, our business and operations will be subject to various risks, including but not limited to, the following:

- The Debtor Entities' bankruptcy filings may cause customers, suppliers and others with whom we have commercial relationships to lose confidence in us and may make it more difficult for us to obtain and maintain such commercial relationships on competitive terms;
- It may be more difficult to retain and motivate our key employees through the process of reorganization, and we may have difficulty attracting new employees;
- Our senior management will be required to spend significant time and effort dealing with the bankruptcy and restructuring activities rather than focusing exclusively on business operations; and

There can be no assurance as to our Debtor Entities' ability to maintain or obtain sufficient financing sources for operations or to fund any reorganization plan and meet future obligations.

We will also be subject to risks and uncertainties with respect to the actions and decisions of creditors and other third parties who have interests in the Chapter 11 Cases that may be inconsistent with our plans. These risks and uncertainties could affect our business and operations in various ways and may increase the time the Debtor Entities have to operate under Chapter 11 bankruptcy protection. Because of the risks and uncertainties associated with our Debtor Entities' Chapter 11

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Cases, we cannot predict or quantify the ultimate impact that events occurring during the Chapter 11 Cases will have on our business, financial condition and results of operations.

We may not be able to successfully implement the Restructuring set forth in the Noteholder Restructuring Support Agreement and the Plan.

The Debtor Entities' consummation of the Plan is contingent upon a number of factors which include, among other things, that:

- the Plan may not be confirmed by the Bankruptcy Court or federal and state regulators may not approve certain elements of the Plan; and

- the Noteholder Restructuring Support Agreement may be terminated.

The Noteholder Restructuring Support Agreement provides that it may be terminated if (among other things): (i) the Bankruptcy Court has not entered an order approving the Disclosure Statement related to the Plan by March 15, 2012; (ii) the Bankruptcy Court has not entered an order confirming the Plan by June 15, 2012; or (iii) the Plan has not become effective by August 1, 2012. Further, certain noteholders may terminate their obligations in their individual capacity if: (i) the examiner finds that any member of DH's board of directors was more likely than not to have committed acts of fraud, willful misconduct, breach of fiduciary duty or any other act which would likely make them unable to satisfy certain standards set out in the Bankruptcy Code; (ii) any modification is made to any Plan Related Document (as defined in the Noteholder Restructuring Support Agreement) that is inconsistent in any material respect with the Plan Related Documents approved by each of the Noteholders as of December 26, 2011; or (iii) the Bankruptcy Court has not entered an order approving the Disclosure Statement by March 15, 2012.

If we are unable to implement the Restructuring of the Debtor Entities, as contemplated by the Noteholder Restructuring Support Agreement and the Plan, it is unclear whether we will be able to reorganize the Debtor Entities' businesses and what, if any, distribution holders of claims against, or equity interests in, the Debtor Entities ultimately would receive with respect to their claims or equity interests. For example, to address our burdensome lease obligations at Roseton and Danskammer, it is a condition precedent to the consummation of the Plan that the rejection damages arising from the rejection of such obligations are determined in an amount not to exceed $300 million (or $190 million net of the claim of PSEG, which has already been allowed by the Bankruptcy Court in the amount of $110 million), subject to the potential wavier of such condition (x) by Dynegy and DH, as plan proponents, to allow such claim in an amount not to exceed $400 million (or $290 million net of PSEG's $110 million allowed claim) or (y) by the Plan Proponents and the Consenting Noteholders (as defined in the Noteholder Restructuring Support Agreement), collectively, to allow such claims in excess of $400 million (or $290 million net of PSEG's $100 million allowed claim). If this condition cannot be satisfied, our Debtor Entities may need to pursue alternative restructuring proposals. Such alternative proposals may include a revision to the Plan by the Plan Proponents or other parties in interest in the Chapter 11 Cases could undertake to formulate and propose a different plan of reorganization. Such a plan of reorganization could involve a reorganization and continuation of the business of DH, the sale of DH as a going concern or an orderly liquidation of the properties and interests in property of DH, any of which may not include the same Plan settlement proposed in the Plan and may result in Dynegy receiving significantly less or no value for its equity interest in DH.

We may not be able to secure confirmation or consummation of the Plan.

The Plan requires the acceptance of a requisite number of holders of claims that are entitled to vote on the Plan, and the approval of the Bankruptcy Court. Furthermore, confirmation and consummation of the Plan are subject to the satisfaction of certain conditions precedent, including, among others, the limitation on the aggregate amount of the damages to be determined to arise from

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the rejection of the Roseton and Danskammer leases, discussed above, and obtaining the necessary approvals from Dynegy's stockholders to amend Dynegy's Second Amended and Restated Certificate of Incorporation to increase the authorized number of shares of common stock and Preferred Stock and/or approve the issuance of common stock upon the conversion of the Preferred Stock. There can be no assurance that such acceptance and approval will be obtained, or that such conditions will be satisfied, and therefore, that the Plan will be confirmed and consummated. In addition, as discussed herein, an examiner has been appointed in these cases to investigate (i) the Debtor Entities' conduct in connection with the prepetition 2011 restructuring and reorganization of the Debtor Entities and their non-Debtor affiliates, (ii) any possible fraudulent conveyances, and (iii) whether DH is capable of confirming a Chapter 11 plan. There can be no assurance that the determinations made by the examiner will not negatively impact the plan proponents' ability to confirm the Plan.

Furthermore, although we believe that the Plan will be confirmed and the Effective Date will occur reasonably soon after the date on which the Bankruptcy Court's order confirming the Plan is entered on the Bankruptcy Court's docket, there can be no assurance as to the timing or as to whether the Effective Date will occur. If the Plan is not confirmed or the Effective Date does not occur, there can be no assurance that any alternative plan of reorganization would not result in Dynegy receiving significantly less or no value for its equity interest in DH. In addition, if a protracted reorganization or liquidation were to occur, there is a substantial risk that Dynegy is likely to continue to face ongoing litigation at significant costs.

The Plan includes provisions for the transfer of certain entities that are Debtor Entities, including Dynegy Danskammer and Dynegy Roseton, to the plan trust, as set forth more fully in the Plan and Disclosure Statement. If any of the Debtor Entities to be transferred are subject to regulation as utility companies as of the time of transfer, the transfer may be subject to the prior approval of one or more regulatory bodies. The Debtor Entities have requested approvals of federal and state regulators, and certain parties have intervened and protested approval, absent the imposition of conditions to resolve their concerns. The approvals by governmental entities may be denied, conditioned or delayed and therefore may not be available when required to facilitate the transfer of such Debtor Entities to the plan trust.

If the Plan is confirmed but the Effective Date does not occur, it may become necessary to amend the Plan to provide for alternative treatment of claims and equity interests which may result in Dynegy receiving significantly less or no value for its equity interest in DH. If any modifications to the Plan are material, it may be necessary to resolicit votes from holders of claims and equity interests adversely affected by the modifications with respect to such Plan.

DPC and DMG receive significant services from certain of Dynegy's other subsidiaries and the loss of such services, as a result of such subsidiaries becoming the subject of a voluntary or involuntary bankruptcy case or otherwise, may have a material adverse impact on DPC's and DMG's businesses, financial condition, results of operations, cash flows and the value of the collateral that will secure the New Secured Notes.

DPC and DMG receive significant services from certain of Dynegy's subsidiaries, including, among others, cash management and energy management services. If the provision of these services were to be delayed, interrupted or otherwise halted for any reason, including if Dynegy or its subsidiaries that provide such services become the subject of a voluntary or involuntary bankruptcy case, this may have a material adverse impact on DPC's and DMG's businesses, financial condition, results of operations, cash flows and the value of the collateral that will secure the New Secured Notes. A replacement supplier of these services may not be found within a reasonable time (or at all) or on economic terms that are commercially reasonable.

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The outcome of ongoing and potential legal proceedings may disrupt the Restructuring, could have a material adverse effect on the Debtor Entities in the event the Plan is not consummated and/or have a material adverse effect on our financial condition, results of operations and cash flows.

We are subject to certain ongoing legal proceedings for which management believes a material loss is reasonably possible. These legal proceedings include the matters set forth in Note 3 Chapter 11 Cases and Note 23 Commitments and Contingencies to our consolidated financial statements for the period ended December 31, 2011.

Specifically with respect to the Reorganization and the DMG Transfer, DH and certain non-debtor affiliates are defendants in three cases filed in the New York Supreme Court by (i) the Owner Lessor Plaintiffs, (ii) Indenture Trustee Plaintiffs, and (iii) the Avenue Plaintiffs (the "Reorganization Lawsuits"). The plaintiffs in these cases challenge, among other things, the DMG Transfer, alleging, inter alia, that the challenged transfer constituted a fraudulent conveyance under New York law or, in the alternative, an unlawful dividend or distribution from a subsidiary to its parent. The plaintiffs also assert causes of action for breach of fiduciary duties against the directors of Dynegy and the managers of DH. In respect to the leases at Roseton and Danskammer, they have also asserted breach of contract and quasi-contract claims against the defendants for alleged breaches of the guarantees related to the leases. The plaintiffs seek judgments setting aside and annulling the challenged DMG Transfer and related transactions or awarding damages. Please read Note 23 Commitments and Contingencies Legal Proceedings - Bondholder Litigation for further discussion.

DH was also a defendant in a prior New York state court action and a prior Delaware state court action asserting similar claims and seeking injunctive relief to prevent the consummation of the Reorganization. The New York action was stayed in favor of the Delaware action. The Delaware court denied the plaintiffs' request for injunctive relief because the plaintiffs to the Delaware action failed to satisfy any of the requisite elements for issuance of an injunction, including, among other things, a reasonable probability of success on the merits of their breach of contract and fraudulent transfer claims. Both the Court of Chancery and the Delaware Supreme Court denied the Delaware plaintiffs' requests for interlocutory appeal and such plaintiffs voluntarily dismissed the Delaware action in August 2011. The New York case was also discontinued by the New York state court on August 19, 2011.

On October 31, 2011, DH and its non-debtor co-defendants filed motions to dismiss the complaints filed by the Avenue Plaintiffs and the Lease Indenture Trustee Plaintiffs. Among other things, the defendants asserted that the complaints failed to state a claim upon which relief could be granted because the plaintiffs are not creditors of the transferor (DGIN) with respect to the asserted fraudulent transfers in respect of the Reorganization, and the defendants did not breach any agreements with the plaintiffs in engaging in the Reorganization.

In accordance with the Noteholder Restructuring Support Agreement, the state court litigation with the Avenue Plaintiffs is currently stayed while the Noteholder Restructuring Support Agreement is in force. In addition, on November 21, 2011, we filed a Notice of Filing of Bankruptcy Petition and of the Automatic Stay in the Restructuring Lawsuits to alert interested parties to the existence of the Chapter 11 Cases and the applicability of the automatic stay to such proceedings.

Also on November 21, 2011, the parties to the action filed by the Indenture Trustee Plaintiffs filed a stipulation to stay that action unless and until the court rules that the automatic stay does not apply during the pendency of these Chapter 11 Cases. Pursuant to a settlement with PSEG entered into on December 13, 2011, PSEG have also agreed to continue the stay with respect to their lawsuit until consummation of the Plan, at which point they have agreed to dismiss it with prejudice. By orders dated January 25, 2012, January 30, 2012, and February 29, 2012, the Court ordered that the Reorganization lawsuits are stayed, and ordered the parties to notify the Court in writing by January 23, 2013 regarding the status of the stay.

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The Plan proposed in the Chapter 11 Cases provides for the settlement and compromise (the "Plan Settlement") of, among other things, all claims and causes of action arising from or related to the Reorganization, including the Reorganization Lawsuits. In the event the Plan is not confirmed, we are likely to continue to face risks related to the Reorganization Lawsuits. We believe the allegations made by the plaintiffs in these proceedings lack merit and intend to vigorously defend our position in these and any other proceedings that may arise involving the Reorganization, the New Credit Agreements, and the DMG Transfer. However, any extraordinary remedy, such as the unwinding of the Reorganization, the New Credit Agreements, or the DMG Transfer, may have a material adverse effect on our financial condition, results of operations and cash flows. Further, parties in interest may pursue other litigation strategies to enforce any claims against the Debtor Entities or us. Litigation is by its nature uncertain and there can be no assurance of the ultimate resolution of any such claims. Any litigation may be expensive, lengthy, and disruptive to our normal business operations and the Reorganization, and a resolution of any such litigation that is unfavorable to us could have a material adverse effect on the Reorganization or on our financial condition, results of operations or cash flows.

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

We have significant indebtedness that could adversely affect our financial health and prevent us from fulfilling certain of our financial obligations.

We have and will continue to have a significant amount of debt outstanding. As of December 31, 2011, we had total debt of approximately $1.8 billion (including debt outstanding under the DMG Credit Agreement and $1.25 billion outstanding related to the Undertaking Agreement with DH). In addition, DH, our wholly-owned equity investment, had debt of approximately $4.7 billion (including $3.6 billion in unsecured senior notes and debentures that are subject to compromise in the bankruptcy process and $1.1 billion outstanding under the DPC Credit Agreement). Such amount of indebtedness could:

- make it difficult to satisfy our financial obligations, including debt service requirements;
- limit our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or other purposes on acceptable terms, on a timely basis or at all;
- limit our financial flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- impact the evaluation of our creditworthiness by counterparties to commercial agreements, both for hedging as well as operating contracts, such as for fuel and transportation, and affect their willingness to transact with us and/or the level of collateral we are required to post under such agreements;
- place us at a competitive disadvantage compared to our competitors that have less debt;
- increase our vulnerability to general adverse economic and industry conditions, and
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, acquisitions and other general corporate purposes.

Further, if gas, power, and capacity prices, where applicable, do not improve, our ability to service our debt obligations will be adversely affected and may require significant operational and balance sheet restructurings.

We conduct virtually all of our operations through our subsidiaries and may be limited in our ability to access funds from these subsidiaries to service debt and or operate our business.

We conduct virtually all of our operations through our subsidiaries and, therefore, depend upon dividends and other intercompany transfers of funds from our subsidiaries to meet our debt service and

other obligations. The ability of our subsidiaries to make distributions or pay dividends will depend on their operating results. In addition, the ability of our subsidiaries to pay dividends and make other payments to us may be restricted by, among other things, applicable corporate and other laws, potentially adverse tax consequences and the terms and covenants of any future outstanding indebtedness, contract or agreements of our subsidiaries, including the DPC Credit Agreement and the DMG Credit Agreement, which limit distributions to $135 million and $90 million per year, respectively. If we are unable to access the cash flow of our subsidiaries, we may have difficulty meeting our debt service obligations. Additionally, we expect that the indenture governing the New Secured Notes will also include covenants further limiting our ability to make distributions of cash, including a requirement to maintain a debt service account for the benefit of the holders of the New Secured Notes. These restrictions on our ability to access cash flow from certain subsidiaries may impair our ability to operate our business as effectively as possible.

Restrictive covenants may adversely affect operations.

The New Credit Agreements contain and the proposed Preferred Stock and indenture governing the New Secured Notes to be issued pursuant to the Plan is expected to contain various covenants that, in the case of the New Credit Agreements limit the ability of DMG and DPC, and in the case of the Preferred Stock and New Secured Notes Indenture limit the ability of us and certain of our subsidiaries, to, among other things:

- incur additional indebtedness;
- pay dividends, repurchase or redeem stock or make investments in certain entities;
- enter into related party transactions;
- create certain liens;
- enter into sale and leaseback transactions;
- enter into any agreements which limit the ability of such subsidiaries to make dividends or otherwise transfer cash or assets to us or certain other subsidiaries;
- create unrestricted subsidiaries;
- impair the security interests;
- issue certain capital stock;
- consolidate, merge, sell or otherwise dispose of all or substantially all of its assets; and
- sell and acquire assets.

These restrictions may affect the ability of DMG, DPC, or us to operate our businesses, may limit our ability to take advantage of potential business opportunities as they arise and may adversely affect the conduct of our current businesses, including restricting our ability to finance future operations and capital needs and limiting our ability to engage in other business activities.

Our access to the capital markets may be limited.

Because of our non-investment grade credit rating, the Chapter 11 Cases of the Debtor Entities, and/or general conditions in the financial and credit markets, our access to the capital markets may be limited. Moreover, the urgency of a capital-raising transaction may require us to pursue additional capital at an inopportune time. Our ability to obtain capital and the costs of such capital are dependent on numerous factors, including:

- covenants in our existing credit agreements;

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- the outcome of the bankruptcy proceedings for the Debtor Entities;
- covenants in the proposed New Secured Notes and Preferred Stock to be issued in connection with the Plan;
- investor confidence in us and the regional wholesale power markets;
- our financial performance and the financial performance of our subsidiaries;
- our levels of debt;
- our requirements for posting collateral under various commercial agreements;
- our credit ratings;
- our cash flow;
- our long-term business prospects; and
- general economic and capital market conditions, including the timing and magnitude of any market recovery.

We may not be successful in obtaining additional capital for these or other reasons. An inability to access capital may limit our ability to meet our operating needs and, as a result, may have a material adverse effect on our financial condition, results of operations and cash flows.

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

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

In carrying out our commercial business strategy, our current non-investment grade credit ratings have resulted and will likely continue to result in requirements that we either prepay obligations or post significant amounts of collateral to support our business. Although the implementation of our commercial business strategy was modified in connection with the Reorganization to leverage the benefits of the New Credit Agreements at our separately financed, bankruptcy-remote portfolios, various commodity trading counterparties may nevertheless be unwilling to transact with us or may make collateral demands that reflect our non-investment grade credit ratings, the counterparties' views of our creditworthiness, as well as changes in commodity prices. We use a portion of our capital resources, in the form of cash, short-term investments, lien capacity, and letters of credit, to satisfy these counterparty collateral demands. Our commodity agreements are tied to market pricing and may require us to post additional collateral under certain circumstances. If market conditions change such that counterparties are entitled to additional collateral, our liquidity could be strained and may have a material adverse effect on our financial condition, results of operations and cash flows. Factors that could trigger increased demands for collateral include changes in our credit rating or liquidity and changes in commodity prices for power and fuel, among others.

Additionally, our non-investment grade credit ratings may limit our ability to obtain additional sources of liquidity, refinance our debt obligations or access the capital markets at the lower borrowing costs that would presumably be available to competitors with higher or investment grade ratings. Should our ratings continue at their current levels, or should our ratings be further downgraded, we would expect these negative effects to continue and, in the case of a downgrade, become more pronounced.

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Despite current indebtedness levels, Dynegy and its subsidiaries may still be able to incur substantially more debt. This could further exacerbate the risks associated with our substantial leverage.

Dynegy and its subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of the indenture governing the New Secured Notes to be issued pursuant to the Plan, the terms of the Preferred Stock, the agreements governing the New Credit Agreements and the agreements governing other existing indebtedness will not or do not fully prohibit Dynegy or its subsidiaries from doing so. Any such indebtedness may reduce the cash flow available to redeem the Preferred Stock or make principal and interest payments on the New Secured Notes, and an exercise by the holder of such indebtedness of their liens may result in Dynegy losing the benefit of the assets secured by such liens, including all of Dynegy's indirect interests in DMG and DPC. If new debt is added to Dynegy's and it subsidiaries' current debt levels, the related risks that they now face could intensify.

Our ability to use our federal net operating losses or alternative minimum tax credits to offset our future taxable income may be limited under Sections 382 and 383 of the Internal Revenue Code.

Our ability to utilize previously incurred federal net operating losses ("NOLs") and alternative minimum tax ("AMT") credits to offset future taxable income would be limited if we were to undergo an "ownership change" within the meaning of Section 382 of the Internal Revenue Code (the "Code"). In general, an ownership change occurs whenever the percentage of the stock of a corporation owned by "5-percent shareholders" (within the meaning of Section 382 of the Code) increases by more than 50 percentage points over the lowest percentage of the stock of such corporation owned by such "5-percent shareholders" at any time over the preceding three years. Under certain circumstances, issuances or acquisitions of Dynegy Inc.'s common stock or sales or dispositions of Dynegy Inc.'s common stock by stockholders could trigger an "ownership change," and we generally do not have control over the amount or timing of any such transactions in Dynegy Inc.'s common stock.

An ownership change under Section 382 of the Code would establish an annual limitation on the amount of NOLs and AMT credits that can be utilized in future years, and it is likely that such a limitation would prevent full utilization of our previously incurred NOLs and AMT credits against future taxable income. Depending on prevailing interest rates and our market value at the time, such an ownership change might prevent utilization of all of our NOLs and AMT credits.

If the Plan is approved, our ability to use our NOLs and AMT credits, which total $128 million and $271 million, respectively, at December 31, 2011, will likely be limited or modified on the Effective Date of the Plan as a result of an "ownership change" under Section 382 of the Code and such limitation or modification will likely be significant. NOLs or AMT credits existing on the Effective Date of the Plan will be available to offset taxable income generated as a result of the bankruptcy or, alternatively, under Section 108 of the Code, Dynegy may elect to reduce certain tax attributes by some or all of the taxable income generated as a result of the bankruptcy. Our ability to utilize certain tax attributes including NOLs and AMT credits that remain after the Effective Date of the Plan will be subject to further limitations and elections as we emerge from bankruptcy. Further limitations on our use of tax attributes will apply if we undergo another "ownership change" within the meaning of Section 382 of the Code. The magnitude of such limitations and their effect on us are difficult to assess and depend in part on our value at the time of any such ownership change and the prevailing federal long-term tax exempt rate.

If the shares of Preferred Stock proposed to be issued pursuant to the Plan are not redeemed prior to their mandatory conversion, such conversion will dilute the ownership interests of our stockholders.

The Plan provides for the issuance of $2.1 billion of Preferred Stock. The Preferred Stock will accrue dividends, commencing on November 7, 2011, at 4 percent through December 31, 2013,

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8 percent thereafter through December 31, 2014 and 12 percent thereafter. The dividends will not be paid in cash but will accrue. The Preferred Stock will not be convertible at the option of the holder but will mandatorily convert into common stock, if not earlier redeemed, on the earlier of December 31, 2015 or a bankruptcy event with respect to us or certain of our subsidiaries. Based on our capital structure anticipated to be in effect upon consummation of the Plan, such shares of Preferred Stock are expected to be convertible in to 97 percent of our fully diluted common stock (assuming conversion on such date) and excluding any equity incentive awards to the employees. We may not have the financial resources necessary to redeem the Preferred Stock prior to conversion. If that is the case, the issuance of our common stock pursuant to the mandatory conversion feature of the Preferred Stock will significantly dilute the ownership interests of existing stockholders and could affect the trading price of our common stock upon issuance. In addition, the possibility of conversion of the Preferred Stock into shares of our common stock could depress the price of our common stock.

Risks Related to the Operation of Our Business

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

Because we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other power markets on a term basis, we are not guaranteed any rate of return on our capital investments. Rather, our financial condition, results of operations and cash flows will depend, in large part, upon prevailing market prices for power and the fuel to generate such power. Wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable. Such factors that may materially impact the power markets and our financial results include:

- economic conditions;
- the existence and effectiveness of demand-side management;
- conservation efforts and the extent to which they impact electricity demand;
- regulatory constraints on pricing (current or future) or the functioning of the energy trading markets and energy trading generally;
- the proliferation of advanced shale gas drilling increasing domestic natural gas supplies;
- fuel price volatility; and
- increased competition or price pressure driven by generation from renewable sources.

Many of our facilities operate as "merchant" facilities without long-term power sales agreements. Consequently, there can be no assurance that we will be able to sell any or all of the electric energy, capacity or ancillary services from those facilities at commercially attractive rates or that our facilities will be able to operate profitably. This could lead to less favorable financial results as well as future impairments of our property, plant and equipment or to the retirement of certain of our facilities resulting in economic losses and liabilities.

Given the volatility of commodity power prices, to the extent we do not secure long-term power sales agreements for the output of our power generation facilities, our revenues and profitability will be subject to increased volatility, and our financial condition, results of operations and cash flows could be materially adversely affected. Further, declines in the market prices of natural gas and wholesale electricity have reduced the outlook for cash flow that can be expected to be generated by us in the next several years.

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Our commercial strategy may not be executed as planned or may result in lost opportunities.

We seek to commercialize our assets through sales arrangements of various types. In doing so, we attempt to balance a desire for greater predictability of earnings and cash flows in the short- and medium-terms with a belief that commodity prices will rise over the longer term, creating upside opportunities for those with unhedged generation volumes. Our ability to successfully execute this strategy is dependent on a number of factors, many of which are outside our control, including market liquidity, the availability of counterparties willing to transact with us or to transact with us at prices we believe are commercially acceptable, the availability of liquidity to post collateral in support of our derivative instruments, and the reliability of the systems comprising our commercial operations function. The availability of market liquidity and willing counterparties could be negatively impacted by poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties as well as counterparties' views of our creditworthiness. If we are unable to transact in the short- and medium-terms, our financial condition, results of operations and cash flows will be subject to significant uncertainty and volatility. Alternatively, significant contract execution for any such period may precede a run-up in commodity prices, resulting in lost upside opportunities and mark-to-market accounting losses causing significant variability in net income and other GAAP reported measures.

We are exposed to the risk of fuel and fuel transportation cost increases and interruptions in fuel supplies.

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

Moreover, profitable operation of many of our coal-fired generation facilities is highly dependent on coal prices and coal transportation rates. Power generators in the midwest and the northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. We have entered into term contracts for PRB coal, which we use for our coal facilities in the midwest. Our expected coal requirements are 100 percent contracted and priced for 2012. Our forecast coal requirements for 2013 are 62 percent committed. Those volumes are unpriced but are subject to a price collar structure. Our coal transportation requirements are 100 percent contracted and priced through 2013. Coal transportation rates will be renewed in 2014 at levels higher than our current rates. The low sulfur content coal used at our facilities in order to meet the requirements of our air permits limits our coal supply options, creating risks in terms of our ability to procure firm coal supplies for periods and prices we believe are favorable.

Further, any changes in the costs of coal, fuel oil, natural gas or transportation rates and changes in the relationship between such costs and the market prices of power will affect our financial results. If we are unable to procure fuel for physical delivery at prices we consider favorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Our costs of compliance with existing environmental requirements are significant, and costs of compliance with new environmental requirements or factors could materially adversely affect our financial condition, results of operations and cash flows.

Our business is subject to extensive and frequently changing environmental regulation by federal, state and local authorities. Such environmental regulation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, transportation, treatment, storage and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances (including GHG) into the environment, and in connection with

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environmental impacts associated with cooling water intake structures. Existing environmental laws and regulations may be revised or reinterpreted, new laws and regulations may be adopted or may become applicable to us or our facilities, and litigation or enforcement proceedings could be commenced against us. Proposals being considered by federal and state authorities (including proposals regarding regulation of GHGs) could, if and when adopted or enacted, require us to make substantial capital and operating expenditures or consider retiring certain of our facilities. If any of these events occur, our financial condition, results of operations and cash flows could be materially adversely affected.

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

With the continuing trend toward stricter environmental standards and more extensive regulatory and permitting requirements, our capital and operating environmental expenditures are likely to be substantial and may significantly increase in the future.

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

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

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

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

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

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

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

We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Electric energy customers, wholesale energy suppliers and transporters often seek financial guarantees, credit support such as letters of credit, and other assurances that their energy contracts will be satisfied. Companies with which we compete may have greater resources in these areas. In addition, certain of our current facilities are relatively old. Newer plants owned by competitors will often be more efficient than some of our plants, which may put these plants at a competitive disadvantage. Over time, some of our plants may become unable to compete because of the construction of new plants, and such new plants could have a number of advantages including: more efficient equipment, newer technology that could result in fewer emissions, or more advantageous locations on the electric transmission system. Additionally, these competitors may be able to respond more quickly to new laws and regulations because of the newer technology utilized in their facilities or the additional resources derived from owning more efficient facilities. Taken as a whole, the potential disadvantages of our aging fleet could result in lower run-times or even early asset retirement.

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

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

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

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

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

A majority of the employees at our facilities are subject to collective bargaining agreements with various unions. Additionally, unionization activities, including votes for union certification, could occur at our non-union generating facilities in our fleet. If union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor is uncertain. Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms could have a material adverse effect on our financial condition, results of operations and cash flows.

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Our ability to comply with our Consent Decree may be materially adversely impacted by our future operating cash flows or unforeseen labor costs.

As a result of the Consent Decree, we are required to not operate certain of our power generating facilities after specified dates unless certain emission control equipment is installed. As of December 31, 2011, only Baldwin Unit 2 has material outstanding Consent Decree work yet to be performed, which is scheduled for completion by the end of 2012. We have incurred significant costs in complying with the Consent Decree and anticipate the remainder of the equipment installations to incur additional significant costs. Further, we are exposed to the risk of price increases in the costs of labor and to the risk that counterparties to the construction contracts may fail to perform, in which case we would be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and possibly cause delays to the project timelines. Further, our production may be affected if we fail to meet certain performance standards under the Consent Decree.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

We have included descriptions of the location and general character of our principal physical operating properties by segment in "Item 1. Business," which is incorporated herein by reference. Substantially all of the assets of the Coal segment, including the power generation facilities owned by DMG, are pledged as collateral to secure the repayment of, and our other obligations under, the DMG Credit Agreement. Substantially all of the assets of the Gas segment, including the power generation facilities owned by DPC, an indirect wholly-owned subsidiary of DH, are pledged as collateral to secure the repayment of, and other obligations under, the DPC Credit Agreement. Please read Note 19 Debt for further discussion.

Our principal executive office located in Houston, Texas, is held under a lease by DH that expires in December 2017 (the "Wells Fargo Lease"). On November 14, 2011, we entered into a new lease that expires in 2022 for our principal executive office to be located at 601 Travis in Houston, Texas. We anticipate moving the principal executive office to the new location in the second quarter of 2012. Efforts to sublease and/or initiate landlord recapture of the vacated office space are underway and will continue until a viable solution is achieved. We also lease additional offices or warehouses in the states of California, Illinois, New York, and Texas.

Item 3. ***Legal Proceedings***

Please read Note 23 Commitments and Contingencies Legal Proceedings for a description of our material legal proceedings, which is incorporated herein by reference.

Item 4. ***Mine Safety Disclosures***

Not applicable.

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PART II

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

Our common stock, $0.01 par value per share, is listed and traded on the New York Stock Exchange ("NYSE") under the ticker symbol "DYN." The number of stockholders of record of our common stock as of March 2, 2012, based upon records of registered holders maintained by our transfer agent, was 11,360.

On May 21, 2010, our stockholders approved a reverse stock split of outstanding common stock at a reverse ratio of 1-for-5. This reverse stock split was effected on May 25, 2010. The following table sets forth, for the fiscal periods indicated, the high and low closing sales prices for our common stock on the NYSE after giving effect to this reverse stock split (including for share prices prior to May 25, 2010), as reported on the NYSE Composite Tape.

Summary of Dynegy's Common Stock Price

	High	Low
2012:		
First Quarter (through March 2, 2012)	$ 2.85	$ 1.26
2011:		
Fourth Quarter	$ 3.89	$ 2.24
Third Quarter	6.64	3.55
Second Quarter	6.45	5.54
First Quarter	6.29	5.44
2010:		
Fourth Quarter	$ 5.89	$ 4.44
Third Quarter	5.10	2.78
Second Quarter	6.80	3.85
First Quarter	9.95	6.10

During the fiscal years ended December 31, 2011 and 2010, our Board of Directors did not elect to pay a cash common stock dividend. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Financing Activities Dividends on Common Stock" for further discussion of our dividend policy and the impact of dividend restrictions contained in the Noteholder Restructuring Support Agreement. We have not paid a dividend on any class of our common stock since 2002. Any decision to pay a dividend will be at the discretion of our Board of Directors, and subject to the terms of our then-outstanding indebtedness, but we do not expect to pay a dividend on our common stock in the foreseeable future.

Shareholder Agreements. In November 2009, as part of the transactions with LS Power, Dynegy and LS Power terminated a then-existing shareholder agreement and entered into a second shareholder agreement (the "New Shareholder Agreement") which, among other things, generally restricts LS Power from increasing its ownership for a specified period up to 30 months. The New Shareholder Agreement does not, however, include any of the special rights (such as Board rights, special approval rights or preemption rights) previously associated with LS Power's ownership. The New Shareholder Agreement expires in accordance with its terms in June 2012.

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Stockholder Return Performance Presentation. The graph below compares the cumulative 5-year total return of holders of our common stock with the cumulative total returns of the S&P Midcap 400 index and a customized peer group. The peer group includes: Calpine Corp., NRG Energy Inc. and GenOn Energy. In 2010, RRI Energy and Mirant Corp merged, resulting in GenOn Energy. The graph tracks the performance of a $100 investment in our common stock, the peer group, and the index (with the reinvestment of all dividends) from December 31, 2006 to December 31, 2011.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Dynegy Inc., the S&P Midcap 400 Index, and a Peer Group

*$100 invested on 12/31/06 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	12/06	12/07	12/08	12/09	12/10	12/11
Dynegy Inc.	100.00	98.62	27.62	25.00	15.52	7.65
S&P Midcap 400	100.00	107.98	68.86	94.60	119.80	117.72
Peer Group	100.00	166.19	64.81	74.85	70.91	71.21

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

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 to October 31, 2011		$		N/A
November 1 to November 30, 2011		$		N/A
December 1 to December 31, 2011	2,217	$ 2.84		N/A
Total	2,217	$ 2.84		N/A

These were the only repurchases of equity securities made by Dynegy during the three months ended December 31, 2011. We do not have a stock repurchase program.

Securities Authorized for Issuance Under Equity Compensation Plans

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

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Item 6. ***Selected Financial Data***

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

	Year Ended December 31,				
	2011(2)	2010	2009	2008	2007
	(in millions, except per share data)				
Statement of Operations Data(1):					
Revenues	$ 1,585	$ 2,323	$ 2,468	$ 3,324	$ 2,918
Depreciation and amortization expense	(325)	(392)	(335)	(346)	(306)
Goodwill impairment			(433)		
Impairment and other charges, exclusive of goodwill impairment shown separately above	(6)	(148)	(538)		
General and administrative expenses	(135)	(163)	(159)	(157)	(203)
Operating income (loss)	(236)	(11)	(834)	744	576
Loss on deconsolidation of DH (2)	(1,657)				
Interest expense and debt extinguishment costs	(378)	(363)	(461)	(427)	(384)
Income tax (expense) benefit	632	197	315	(90)	(140)
Income (loss) from continuing operations	(1,645)	(235)	(1,040)	188	105
Income (loss) from discontinued operations (3)		1	(222)	(17)	166
Net income (loss)	$ (1,645)	$ (234)	$ (1,262)	$ 171	$ 271
Net income (loss) attributable to Dynegy Inc. common stockholders	(1,645)	(234)	(1,247)	174	264
Basic earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders	$ (13.48)	$ (1.96)	$ (6.25)	$ 1.14	$ 1.10
Basic net income (loss) per share attributable to Dynegy Inc. common stockholders	(13.48)	(1.95)	(7.60)	1.04	1.75
Diluted earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders	$ (13.48)	$ (1.96)	$ (6.25)	$ 1.14	$ 1.10
Diluted net income (loss) per share attributable to Dynegy Inc. common stockholders	(13.48)	(1.95)	(7.60)	1.04	1.75
Shares outstanding for basic EPS calculation	122	120	164	168	151
Shares outstanding for diluted EPS calculation	122	121	165	168	151
Cash dividends per common share	$	$	$	$	$
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ (20)	$ 423	$ 135	$ 319	$ 341
Net cash provided by (used in) investing activities	(254)	(534)	251	(102)	(817)
Net cash provided by (used in) financing activities	379	(69)	(608)	148	433
Capital expenditures, acquisitions and investments	(51)	(531)	(594)	(640)	(504)

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	December 31,				
	2011(2)	2010	2009	2008	2007
	(in millions)				
Balance Sheet Data:					
Current assets	$ 672	$ 2,244	$ 2,038	$ 2,803	$ 1,663
Current liabilities	159	1,565	1,847	1,702	999
Property and equipment, net	3,334	6,273	7,117	8,934	9,017
Total assets	4,127	10,013	10,953	14,213	13,221
Long-term debt (excluding current portion)	1,834	4,626	4,775	6,072	5,939
Current portion of long-term debt	4	148	807	64	51
Capital leases not already included in long-term debt			4	4	5
Total equity	1,112	2,746	2,979	4,485	4,529

(1) The merger with LS Power (April 2, 2007) was accounted for in accordance with the purchase method of accounting and the results of operations attributable to the acquired business is included in our financial statements and operating statistics beginning on the acquisition's effective date for accounting purposes.

(2) DH was deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

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

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

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

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

OVERVIEW

We are a holding company 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 segments in our consolidated financial statements: (i) the Coal segment ("Coal"); (ii) the Gas segment ("Gas") and (iii) the Dynegy Northeast segment ("DNE"). Prior to 2011, we reported results for the following segments: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Accordingly, we have recast the corresponding items of segment information for all prior periods. Our consolidated financial results also reflect corporate-level expenses such as interest and depreciation and amortization. General and administrative expenses are allocated to each reportable segment. Our investment in PPEA Holding Company, which was sold in the fourth quarter 2010, is included in Other for reporting purposes.

Chapter 11 Cases. On November 7, 2011, the Debtor Entities filed the Chapter 11 Cases. Neither Dynegy nor any of its direct or indirect subsidiaries, other than the five Debtor Entities, sought relief under Chapter 11 of the Bankruptcy Code, and none of those entities are debtors under Chapter 11 of the Bankruptcy Code. The normal day-to-day operations of the coal-fired power generation facilities held by DMG and the natural gas-fired power generation facilities held by DPC have continued without interruption. The commencement of the Chapter 11 Cases did not constitute a default under either of the New Credit Agreements. Please read Item 1. Business and Note 3 Chapter 11 Cases for further discussion of the Chapter 11 Cases and the related Noteholder Restructuring Support Agreement and Plan of Reorganization.

As a result of the Chapter 11 Cases, we deconsolidated our investment in DH and its wholly-owned subsidiaries as of November 7, 2011. Financial statements presented after November 7, 2011 reflect our investment in and advances to, and the results of operations of, DH and its wholly-owned subsidiaries under the equity method of accounting. For further discussion, please read Note 3 Chapter 11 Cases Accounting Impact.

Reorganization Activity. On August 5, 2011, we completed the Reorganization of our legal entity structure to facilitate the execution of the New Credit Agreements. The New Credit Agreements consist of the DPC Credit Agreement, a $1,100 million, five year senior secured term loan facility available to DPC, and the DMG Credit Agreement, a $600 million, five year senior secured term loan facility available to DMG. Please read Note 19 Debt DMG Credit Agreement and DH Debt Obligations DPC Credit Agreement for further discussion of the New Credit Agreements.

Services Agreements. In connection with the Reorganziation, subsidiaries from our Gas, Coal and DNE segments each entered into Services Agreements with other Dynegy entities to provide certain services. Please read Note 20 Related Party Transactions Services Agreements for further discussion.

DMG Transfer. On September 1, 2011, Dynegy and DGIN completed the DMG Transfer. In exchange for the equity of Coal HoldCo, Dynegy entered into an Undertaking Agreement with DGIN under which Dynegy agreed to make certain specified payments to DGIN aggregating approximately $2.1 billion through October 15, 2026. Subsequent to the exchange, DGIN assigned its rights to receive payments under the Undertaking Agreement to DH in exchange for the Promissory Note in the amount of $1.25 billion that matures in 2027. As a condition to Dynegy's consent to the Assignment, the Undertaking Agreement was amended and restated to be between DH and Dynegy and to provide for the reduction of Dynegy's obligations if the outstanding principal amount of the Senior Notes decreases as a result of any exchange offer, tender offer or other purchase or repayment by Dynegy or

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its subsidiaries (other than DH and its subsidiaries, unless Dynegy guarantees the debt securities of DH or such subsidiary in connection with such exchange offer, tender offer or other purchase or repayment); provided that such principal amount is retired, cancelled or otherwise forgiven. Upon the Effective Date, Dynegy and DH will cancel the Undertaking Agreement and Dynegy's obligations under the Undertaking Agreement will be fully satisfied and extinguished. For further discussion, please read Note 1 Organization and Operations Reorganization DMG Transfer and Note 20 Related Party Transactions Undertaking Agreement.

Sithe Senior Notes. On September 26, 2011, we completed the Sithe Tender Offer, in which we repurchased approximately $192 million of the Sithe Senior Notes for approximately $217 million. In connection with the Sithe Tender Offer and consent solicitation, we amended the indenture under which the Sithe Senior Notes were issued to eliminate or modify substantially all of the restrictive covenants, certain events of default and certain other provisions and satisfied and discharged the indenture and remaining Sithe Senior Notes. Please read Note 19 Debt DH Debt Obligations Sithe Senior Notes for further discussion.

Business Discussion

The following is a brief discussion of each of our segments, including a list of key factors that have affected, and are expected to continue to affect, their respective earnings and cash flows. We also present a brief discussion of our corporate-level expenses.

Power Generation Business

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

- Prices for power, natural gas, coal and fuel oil, which in turn are largely driven by supply and demand. Demand for power can vary due to weather and general economic conditions, among other things. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation. The proliferation of advanced shale gas drilling has increased domestic natural gas supplies which has caused a decline in power prices;

- The relationship between electricity prices and prices for natural gas and coal, commonly referred to as the "spark spread" and "dark spread," respectively, which impacts the margin we earn on the electricity we generate; and

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

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

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

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

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

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- Our ability to operate and market production from our facilities during periods of planned/unplanned electric transmission outages;

- Our ability to post the collateral necessary to execute our commercial strategy;

- The cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive (please read Item 1. Business Environmental Matters for further discussion); and

- Market supply conditions resulting from federal and regional renewable power mandates and initiatives.

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

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

Coal. Our assets in Coal are primarily coal-fired facilities but also include two natural gas-fired peaking facilities. The following specific factors affect or could affect the performance of this reportable segment:

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

- Costs of transportation related to coal deliveries;

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

- Regional renewable energy mandates and initiatives that may alter supply conditions within the ISO and our generating units' positions in the aggregate supply stack;

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

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

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

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

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

The costs incurred to demolish and remediate the South Bay facility; and

Changes in the existing bilateral CAISO resource adequacy markets and any resulting effect on future capacity revenues.

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DNE. Our assets in DNE include natural gas, fuel oil and coal-fired power generating facilities. To the extent we continue to be the operator and commercial manager of these assets, the following specific factors impact or could impact the performance of this reportable segment:

- The amount of damages that will arise as a result of the termination of the DNE leases in the Chapter 11 Cases;
- The amount of time that will be required to secure necessary regulatory approval to transfer operational control of the Roseton and Danskammer facilities;
- Future operating costs, including property taxes and labor;
- Our ability to maintain sufficient coal and fuel oil inventories, including continued deliveries of coal and oil in a consistent and timely manner, and continued access to uninterrupted natural gas supplies, to serve the winter and summer on-peak loads;
- The additional costs imposed by state-driven environmental compliance initiatives aimed at reducing mercury emission levels and other constituents such as CO_2, NO_x and SO_2 as well as more restrictive measures for cooling water intakes for fish protection;
- Changes in NYISO market rules or state-specific mandates that favor and/or subsidize renewable energy sources and demand response initiatives; and
- Our ability to preserve and/or capture value around planned transmission upgrades designed to improve transfer limits around known constraints.

Other

Other includes corporate expenses such as interest, depreciation and amortization and taxes. Significant items impacting future earnings and cash flows include:

- Resolution of the Chapter 11 Cases and our ability to obtain support for the Plan;
- Access to capital markets on reasonable terms, interest rates and other costs of liquidity;
- Interest expense; and
- Income taxes, which will be impacted by our ability to realize value from our NOLs and AMT credits.

General and administrative costs are allocated to each reportable segment in accordance with the relevant Services Agreement. They will be impacted by, among other things, (i) staffing levels and associated expenses; (ii) funding requirements under our pension plans; (iii) any future corporate-level litigation reserves or settlements and (iv) our ability to realize planned cost savings reflected in our financial forecasts.

Other also includes our legacy CRM operations, which primarily consists of a minimal number of legacy natural gas agreements that were novated to a third party in 2011.

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

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and associated margin and collateral requirements, facility maintenance costs and other costs such as payroll.

As a result of the Reorganization, our primary sources of internal liquidity are cash flows from operations and cash on hand. Cash on hand includes cash proceeds from the DPC Credit Agreement and the DMG Credit Agreement, which is limited in use and distribution as further described in footnote 1 to the liquidity table below. Please read Note 19 Debt for further information.

Our primary sources of external liquidity are proceeds from capital market transactions to the extent we engage in such transactions. Please read "Capital-Structuring Transactions" below for more detail.

Current Liquidity. The following tables summarize our liquidity position, including the consolidated liquidity of DH, our wholly-owned subsidiary accounted for as an equity method investment subsequent to its bankruptcy filing on November 7, 2011, at March 2, 2012 and December 31, 2011:

	March 2, 2012					
	DMG(1)	**Other(2)**	**Dynegy Inc. (as reported)**	**DPC(1)**	**Other DH(3)**	**Total**
	(in millions)					
LC capacity, inclusive of required reserves (4)	$ 42	$	$ 42	$ 370	$ 27	$ 439
Less: Required reserves (4)	(1)		(1)	(11)	(1)	(13)
Less: Outstanding letters of credit	(35)		(35)	(340)	(26)	(401)
LC availability	6		6	19		25
Cash and cash equivalents	127	309	436	56	343	835
Collateral posting account (5)	70		70	154		224
Total available liquidity (6)(7)	$ 203	$ 309	$ 512	$ 229	$ 343	$ 1,084

	December 31, 2011					
	DMG(1)	**Other(2)**	**Dynegy Inc. (as reported)**	**DPC(1)**	**Other DH(3)**	**Total**
	(in millions)					
LC capacity, inclusive of required reserves (4)	$ 103	$	$ 103	$ 456	$ 27	$ 586
Less: Required reserves (4)	(3)		(3)	(13)	(1)	(17)
Less: Outstanding letters of credit	(38)		(38)	(386)	(26)	(450)
LC availability	62		62	57		119
Cash and cash equivalents	79	317	396	32	366	794
Collateral posting account (5)	69		69	132		201
Total available liquidity (6)(7)	$ 210	$ 317	$ 527	$ 221	$ 366	$ 1,114

(1) On August 5, 2011, we borrowed $1,100 million under the DPC Credit Agreement and $600 million under the DMG Credit Agreement, and repaid amounts outstanding under and terminated DH's Fifth Amended and Restated Credit Agreement. A portion of the proceeds from the DPC Credit Agreement borrowing was used to make a $200 million restricted payment to a parent holding company of DPC and a portion of the proceeds from the DMG Credit Agreement borrowing was used to make a $200 million restricted payment to a parent holding company of DMG. The DPC Credit Agreement and the DMG Credit Agreement limit further distributions by DPC and DMG to their parents to $135 million and $90 million per fiscal year, respectively,

provided certain conditions are met. Please read "DPC and DMG Restricted Payments below" and Note 19 Debt for further discussion.

(2) Other cash consists of $280 million and $280 million at Coal HoldCo and $29 million and $37 million at Dynegy as of March 2, 2012 and December 31, 2011, respectively.

(3) Other DH cash consists of $306 million and $305 million at Dynegy Gas HoldCo, LLC ("Gas HoldCo"); $11 million and $28 million at Dynegy Administrative Services Company; $24 million and $30 million at DH; and $2 million and $3 million at Dynegy Northeast Generation, Inc. as of March 2, 2012 and December 31, 2011, respectively.

(4) The LC facilities were collateralized with cash proceeds received under the New Credit Agreements, and such proceeds from the DMG Credit Agreement are currently included in Restricted cash and investments on our consolidated balance sheets. The amount of the LC availability plus any unused required reserves of 3 percent on the unused capacity, may be withdrawn from the LC facilities with three days written notice for unrestricted use in the operations of the applicable entity. LC capacity as of March 2, 2012 reflects a reduction in capacity for DMG and DPC following the requested release of unused cash collateral from restricted cash. Actual commitment amounts under each of the New Credit Agreements have not been reduced, and DMG and DPC can increase the LC capacity up to the original commitment amount in the future by posting additional cash collateral.

(5) The collateral posting account included in the above liquidity tables is restricted per the New Credit Agreements and may be used for future collateral posting requirements or released per the terms of the applicable DPC Credit Agreement or DMG Credit Agreement. Please read Note 19 Debt for further discussion. Amounts related to the DMG Credit Agreement are included in Restricted cash and investments on our consolidated balance sheets.

(6) The DH Contingent LC Facility is not included in Total available liquidity as there is currently no capacity available under the facility. Under the terms of the Contingent LC Facility, up to $150 million of capacity can become available, contingent on specified changes in forward spark spreads and power prices for 2012. DH's status as a Debtor Entity may limit availability. Please read Note 19 Debt for further discussion.

(7) Does not reflect our ability to use the first lien structure as described in "Collateral Postings" below.

Capital-Structuring Transactions. We believe the Reorganization and the New Credit Agreements aligned our asset base and increased our flexibility to address additional potential debt restructuring activities. On September 1, 2011, Dynegy and DGIN effected the DMG Transfer whereby DGIN transferred 100 percent of the outstanding membership interests of Coal HoldCo to Dynegy. Please read Note 1 Organization and Operations Reorganization DMG Transfer for further discussion. Further, on November 7, 2011, the Debtor Entities filed the Chapter 11 Cases. The Chapter 11 Cases were filed in accordance with the Noteholder Restructuring Support Agreement. The Noteholder Restructuring Support Agreement and the Plan set forth the material terms of the Restructuring pursuant to which unsecured claims of DH, including its outstanding senior unsecured notes and debentures and subordinated debentures, will be cancelled in exchange for a combination of (i) $400 million cash, (ii) $1.015 billion aggregate principal amount of New Secured Notes and (iii) $2.1 billion of the Preferred Stock. Please read Note 3 Chapter 11 Cases for further discussion. If we are unable to implement the Restructuring of the Debtor Entities, as contemplated by the Noteholder Restructuring Support Agreement and Plan, we may be required to pursue alternative restructuring proposals which may include exploring alternative sources of external liquidity.

DPC and DMG Restricted Payments. In addition to the $400 million, in the aggregate, of proceeds from the DPC Credit Agreement and the DMG Credit Agreement that was initially distributed to Gas

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HoldCo and Coal HoldCo, respectively, the DPC Credit Agreement and the DMG Credit Agreement allow distributions by DPC and DMG to their parents of up to $135 million and $90 million per year, respectively, provided the borrower and its subsidiaries possess at least $50 million of unrestricted cash and short-term investments as of the date of the proposed distribution. In December 2011, DPC and DMG made distributions of $135 million and $90 million, respectively, to their parents. Please read Note 19 Debt for further discussion.

Operating Activities

Historical Operating Cash Flows. Our cash flow used in operations totaled $20 million for the twelve months ended December 31, 2011. During the period, our power generation business provided positive cash flow from the operation of our power generation facilities. Our working capital was positive primarily due to lower sparks spreads and warmer weather in December 2011 compared to December 2010 and the timing of our interest payments to service debt partially offset by employee related payments, restructuring costs and collateral posted to satisfy our counterparty collateral demands.

Our cash flow provided by operations totaled $423 million for the twelve months ended December 31, 2010. During the period, our power generation business provided positive cash flow from operations of $938 million from the operation of our power generation facilities, primarily reflecting positive earnings for the period and approximately $290 million of cash received from our futures clearing manager. The receipt of this cash was partly due to lower commodity prices and a reduction of margin requirements; the remaining cash was returned as a result of the posting of $85 million of short-term investments in lieu of cash. Corporate and other operations included a use of cash of approximately $515 million, primarily due to interest payments to service debt and general and administrative expenses.

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

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 prices of natural gas, coal and fuel oil and their correlation to power prices, 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 cost reduction programs, our ability to capture value associated with commodity price volatility and the outcome of the Chapter 11 Cases.

Collateral Postings. We use a significant portion of our capital resources in the form of cash and letters of credit to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The

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following table summarizes our collateral postings to third parties by legal entity at March 2, 2012, December 31, 2011 and December 31, 2010:

	March 2, 2012	December 31, 2011	December 31, 2010
		(in millions)	
Dynegy Midwest Generation, LLC and Dynegy Inc.:			
Cash (1)	$ 14	$ 11	$
Letters of credit	35	38	
Total DMG and Dynegy Inc. (as reported)	49	49	
Dynegy Power, LLC (2):			
Cash	$ 63	$ 44	$
Letters of credit	340	386	
Total DPC	403	430	
Dynegy Holdings, LLC (2):			
Cash and short-term investments (3)	$	$	$ 87
Letters of credit	26	26	375
Total DH	26	26	462

(1) Includes Broker margin account on our consolidated balance sheets, as well as other collateral postings included in Prepayments and other current assets on our consolidated balance sheets. There were no short-term investments in our Broker margin account at March 1, 2012 or December 31, 2011.

(2) These entities were deconsolidated effective November 7, 2011. For further discussion, please read Note 3 Chapter 11 Cases. Includes collateral postings made by DH and its consolidated subsidiaries. Effective November 7, 2011, as a result of DH's bankruptcy filing, DH and its direct and indirect subsidiaries, including DP, were deconsolidated and subsequently accounted for using the equity method of accounting.

(3) As of December 31, 2010, we had $85 million of short-term investments in our Broker margin account on our consolidated balance sheet.

The change in letters of credit postings from December 31, 2010 to December 31, 2011 is primarily due to contractual obligations under certain operational agreements. Collateral postings decreased from December 31, 2011 to March 2, 2012 primarily due to increased usage of collateral efficient agreements.

In addition to cash and letters of credit posted as collateral, we have granted additional permitted first priority liens on the assets already subject to first priority liens under our New Credit Agreements. The additional liens were granted 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 New Credit Agreements. The fair value of DMG's commodity derivatives collateralized by first priority liens, netted by counterparty, included liabilities of $4 million and $3 million at March 2, 2012 and December 31, 2011, respectively. The fair value of DPC's commodity derivatives collateralized by first priority liens, netted by counterparty, included liabilities of $33 million and $92 million at March 2, 2012 and December 31, 2011, respectively. The fair value of DH's commodity derivatives, excluding those held by DPC, collateralized by first priority liens, netted by counterparty, included liabilities of zero, zero and $30 million at March 2, 2012, December 31, 2011, and December 31, 2010, respectively.

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We expect counterparties' future 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. Our ability to use forward economic hedging instruments could be limited due to the collateral requirements the use of such instruments entails.

Investing Activities

Capital Expenditures. We continue to tightly manage our operating costs and capital expenditures. We had approximately $242 million, $333 million and $612 million in capital expenditures during the twelve months ended December 31, 2011, 2010 and 2009, respectively. Our capital spending by reportable segment was as follows:

	December 31,		
	2011	2010	2009
	(in millions)		
Coal	$ 184	$ 274	$ 398
Gas (1)	57	50	91
DNE (1)	1	3	8
Other and eliminations (1)		6	115
Total	$ 242	$ 333	$ 612

(1) Only includes capital expenditures through November 7, 2011 when the legal entities included in these segments were deconsolidated. Please read Note 3 Chapter 11 Cases for further discussion. Capital expenditures for the period from November 8, 2011 to December 31, 2011 related to the legal entities included in these segments, but not shown in the table above, were $22 million, $1 million and zero for Gas, DNE and Other, respectively.

Capital spending in our Coal segment primarily consisted of environmental and maintenance capital projects, as well as approximately $104 million spent on development capital related to the Plum Point Project during the year ended December 31, 2009. Capital spending in our Gas and DNE segments primarily consisted of maintenance projects. The decrease in our capital expenditures from 2010 to 2011 is largely due to the completion of various Consent Decree projects in our Coal segment in 2010.

We expect capital expenditures, including the capital expenditures for DH, for 2012 to approximate $211 million, which is comprised of $132 million, $76 million and $3 million in Coal, Gas and Other, respectively. The $132 million of spending planned for Coal includes approximately $75 million of environmental expenditures, of which approximately $71 million is related to the Consent Decree, approximately $35 million is related to maintenance on our coal and natural gas facilities, approximately $13 million is related to capitalized interest and approximately $9 million in other spending primarily related to maintenance capital projects and environmental projects. The capital budget is subject to revision as opportunities arise or circumstances change.

The Consent Decree was finalized in July 2005. It prohibits us from operating certain of our power generating facilities after certain dates unless specified emission control equipment is installed. We anticipate our total costs associated with the Consent Decree projects, which we expect to incur through early 2013, to be approximately $948 million, which includes approximately $872 million spent to date. As of December 31, 2011, only Baldwin Unit 2 has material outstanding Consent Decree work yet to be performed, which is scheduled for completion by the end of 2012. The estimated capital expenditures required to comply with the remaining Consent Decree work are $71 million and $5 million in 2012 and 2013, respectively. These estimates are based on a number of assumptions about

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uncertainties that are beyond our control, and if we fail to meet certain performance standards under the Consent Decree our production may be affected. Please read Note 23 Commitments and Contingencies Other Commitments and Contingencies Consent Decree for further discussion.

The SPDES permit renewal application at our Roseton power generating facility has been challenged by local environmental groups which contend the existing once-through water cooling system should be replaced with a closed-cycle cooling system. A decision to install a closed-cycle cooling system at the Roseton facility would be made considering all relevant factors at such time, including any relevant costs or applicable remediation requirements. If mandated installation of a closed-cycle cooling system would result in a material capital expenditure that renders the operation of a plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such facility and forego these capital expenditures. In connection with the Chapter 11 Cases, the Debtor Entities have rejected the leases of the Roseton and Danskammer power generation facilities located in Newburgh, New York. The Debtor Entities have remained in physical possession of and have continued to operate the leased facilities to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facilities is permitted to be transitioned. Please read Note 3 Chapter 11 Cases for further discussion regarding the Roseton lease.

Asset Dispositions. Proceeds from asset sales in 2009 totaled $652 million. Of the total $936 million in cash proceeds received at the closing of the LS Power Transactions, $547 million related to the disposition of assets, including our interest in the Sandy Creek Project. We also received $175 million from the release of restricted cash on our consolidated balance sheets that had been used to support our funding commitment to the Sandy Creek Project. Please read Note 5 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further information. The remaining $214 million of cash received upon closing the LS Power Transactions related to the issuance of $235 million of notes payable and is included in Financing Activities. Please read " Financing Activities" below and Note 20 Related Party Transactions Transactions with LS Power for further discussion.

Additionally, during 2009, we sold the Heard County power generation facility for approximately $105 million, net of transaction costs. Please read Note 5 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Heard County for further discussion.

Other Investing Activities. Cash inflows related to maturities of short-term investments for the twelve months ended December 31, 2011 totaled $475 million. Cash outflows for purchases of short-term investments during the twelve months ended December 31, 2011 totaled $284 million.

Cash inflows related to short-term investments during the year ended December 31, 2010 totaled $317 million, reflecting maturities and early redemptions of short-term investments. Cash outflows related to purchases of short-term investments during the year ended December 31, 2010 totaled $508 million.

Cash inflows related to short-term investments during the year ended December 31, 2009 totaled $17 million, reflecting a distribution of our short-term investments. Cash outflows related to short-term investments during the year ended December 31, 2009 totaled $27 million.

There was an $88 million cash inflow related to restricted cash balances during the twelve months ended December 31, 2011 primarily due to (i) the release of $850 million upon the termination of DH's former Fifth Amended and Restated Credit Agreement, (ii) the release of $43 million upon the completion of the Sithe Tender Offer, and (iii) the release of $50 million related to the expiration of a security and deposit agreement. These decreases in restricted cash were partially offset by increases of $653 million, $171 million and $27 million associated with the DPC Credit Agreement, the DMG Credit Agreement, and a DH Letter of Credit Reimbursement and Collateral Agreement, respectively.

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There was a $15 million cash outflow related to our funding commitment obligation under the PPEA Sponsor Support Agreement and a $3 million cash outflow due to changes in restricted cash balances during the year ended December 31, 2010. There was a $190 million cash inflow during the year ended December 31, 2009 related to changes in restricted cash balances primarily due to the release of $175 million of restricted cash that was used to support our funding commitment to the Sandy Creek Project.

Cash flows from investing activities reflects a decrease of $303 million related to the deconsolidation of DH effective November 7, 2011. This amount represents the cash held by DH and its consolidated subsidiaries on November 7, 2011.

Other included $12 million and $3 million of property insurance claim proceeds during the twelve months ended December 31, 2011 and 2009, respectively.

Financing Activities

Historical Cash Flow from Financing Activities. Cash flow provided by financing activities totaled $379 million during the twelve months ended December 31, 2011. Proceeds from long-term borrowings of $2,020 million, net of $46 million of debt issuance costs, consisted of:

- $1,078 million of cash proceeds from the $1,100 million DPC Credit Agreement;
- $588 million of cash proceeds from the $600 million DMG Credit Agreement; and
- $400 million from a borrowing under the revolving portion of DH's former Fifth Amended and Restated Credit Agreement.

We also received $3 million from the proceeds of stock option exercises. These proceeds partially offset repayments of borrowings of $1,624 million, consisting of the following:

- $850 million term facility under DH's former Fifth Amended and Restated Credit Agreement;
- $400 million under the revolving portion of DH's former Fifth Amended and Restated Credit Agreement;
- $80 million in repayment of our 6.875 percent senior notes;
- $68 million in repayment of our Tranche B term loan;
- $225 million in repayment of borrowings on Sithe senior debt; and
- $1 million in payments on the DMG Credit Agreement.

We also paid debt extinguishment costs of $21 million in connection with the termination of the Sithe senior debt.

Net cash used in financing activities during the twelve months ended December 31, 2010 totaled $69 million due to the payments of $62 million in aggregate principal amount on our Sithe 9.00 percent secured bonds due 2013 and $6 million of financing fees.

Net cash used in financing activities during the twelve months ended December 31, 2009 totaled $608 million. Repayments of borrowings were $890 million, and consisted of the following:

$421 million in aggregate principal amount on our 6.875 percent senior unsecured notes due 2011 ("2011 Notes");

$412 million in aggregate principal amount on our 8.75 percent senior unsecured notes due 2012 ("2012 Notes"); and

$57 million in aggregate principal amount on our Sithe 9.00 percent secured bonds due 2013.

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

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

$130 million under the PPEA Credit Agreement Facility; and

$214 million of cash proceeds from the LS Power Transactions allocated to the issuance of $235 million of 7.5 percent senior unsecured notes due 2015.

These borrowings were partly offset by $16 million of financing fees related to an amendment of DH's former Fifth Amended and Restated Credit Agreement.

Summarized Debt and Other Obligations. The following table depicts our third party debt obligations, and the extent to which they are secured as of December 31, 2011 and 2010:

	December 31, 2011			December 31, 2010
	Dynegy Inc. (as reported)	Other(1)	Total	Total
	(in millions)			
First secured obligations	$ 599	$ 1,097	$ 1,696	$ 918
Unsecured obligations (2)		3,570	3,570	3,644
Lease obligations (3)				590
Sithe secured non-recourse obligation				225
Total obligations	599	4,667	5,266	5,377
Less: Lease obligations (3)				(590)
Other (4)	(11)	(21)	(32)	(13)
Total notes payable and long-term debt (5)	$ 588	$ 4,646	$ 5,234	$ 4,774

(1) Effective November 7, 2011, we deconsolidated DH and its subsidiaries. This column represents debt and other obligations of DH and its subsidiaries that are not included in our balance sheet as debt at December 31, 2011, but are instead reflected in our investment in DH.

(2) DH's unsecured obligations as of December 31, 2011 are subject to compromise as a result of DH's bankruptcy filing on November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

(3) Represents present value of future lease payments associated with the DNE lease financing discounted at 10 percent at December 31, 2010. The DNE lease is held by a subsidiary of DH, and therefore, this obligation was deconsolidated effective November 7, 2011. In December 2011, the Bankruptcy Court entered a stipulated order approving the rejection of the lease. For additional discussion please read Note 3 Chapter 11 Cases and "Contractual Obligations DH" below.

(4) Consists of net discounts on debt.

(5) Does not include letters of credit.

Please read Note 19 Debt for further discussion of these items. Our consolidated debt maturity profile as of December 31, 2011 includes $4 million in 2012, $4 million in 2013, $4 million in 2014, $3 million in 2015, $573 million in 2016 and zero thereafter, all of which relate to the DMG Credit Agreement. The debt maturity profile of DH, excluding the senior notes and debentures that are subject to compromise in the bankruptcy process, as of December 31, 2011 includes $7 million in 2012,

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$7 million in 2013, $6 million in 2014, $6 million in 2015, $1,050 million in 2016 and zero thereafter, all of which relate to the DPC Credit Agreement.

In addition to the third party debt obligations discussed above, Dynegy has a $1.25 billion Undertaking Agreement payable to DH. Please read Note 1 Organization and Operations DMG Transfer and Note 20 Related Party Transactions Undertaking Agreement for further discussion.

Financing Trigger Events. The debt instruments and other financial obligations related to our subsidiaries which have not filed for bankruptcy protection include provisions which, if not met, could require early payment, additional collateral support or similar actions. The trigger events connected to the financing of our non-debtor subsidiaries include the violation of covenants, defaults on scheduled principal or interest payments, including any indebtedness to the extent linked to it by reason of cross-default or cross-acceleration provisions, insolvency events, acceleration of other financial obligations and change of control provisions. Our non-debtor subsidiaries do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events.

The pre-petition debt instruments and other financial obligations related to the Debtor Entities included similar trigger events. The Debtor Entities do not currently pay interest or make other debt service payments on such pre-petition obligations and the conditions necessary for certain of such trigger events may exist. The Debtor Entities have entered into and obtained Bankruptcy Court approval of a $15 million Intercompany Revolving Loan Agreement which includes certain covenants and requirements that, if not met, could require early payment or similar actions.

Financial Covenants. Following the termination of DH's Fifth Amended and Restated Credit Agreement on August 5, 2011, we are no longer subject to any financial covenants.

Dividends on Common Stock. Dividend payments on our common stock are authorized at the discretion of our Board of Directors and applicable law. If, as a result of the Chapter 11 Cases, the transactions contemplated by the Noteholder Restructuring Support Agreement are implemented, there will be restrictions on the ability of the Board of Directors to declare dividends on our common stock. We did not declare or pay a cash dividend on common stock during the year ended December 31, 2011.

Credit Ratings

Our credit rating status is currently "non-investment grade" and our current ratings are as follows:

	Standard & Poor's	Moody's	Fitch
Dynegy Inc.:			
Corporate Family Rating	CC	Caa3	CC
DH:			
Senior Unsecured (1)	D	NR	CCC
DPC:			
Senior Secured	B	B2	B

(1) Moody's Investor Services withdrew its rating of the DH senior unsecured bonds after the Debtor Entities filed the Chapter 11 Cases.

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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. Details on these obligations are set forth below.

Contractual Obligations Dynegy Inc.

The following table summarizes our contractual obligations as of December 31, 2011. The table below does not include contractual obligations of DH and its subsidiaries, as DH was deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases Accounting Impact for further discussion. However, as we continue to own 100 percent of the outstanding equity of DH, we have included a discussion of DH's contractual obligations in "Contractual Obligations DH" below. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Expiration by Period				
	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
	(in millions)				
Long-term debt (including current portion)	$ 588	$ 4	$ 8	$ 576	$
Interest payments on debt	253	55	109	89	
Undertaking payable, including interest	2,075	97	193	193	1,592
Operating leases	22	2	6	4	10
Coal commitments (1)	441	167	188	86	
Pension funding obligations	54	20	34		
Other obligations	1	1			
Total contractual obligations	$ 3,434	$ 346	$ 538	$ 948	$ 1,602

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

Long-Term Debt (Including Current Portion). Total amounts of Long-term debt (including current portion) are related to the DMG Credit Agreement and are included in the December 31, 2011 consolidated balance sheet. Please read Note 19 Debt DMG Credit Agreement for further discussion.

Interest Payments on Debt. Interest payments on debt represent estimated periodic interest payment obligations, excluding the impact of interest rate derivatives, associated with our DMG Credit Agreement. Please read Note 19 Debt DMG Credit Agreement for further discussion.

Undertaking Payable. We have a $1.25 billion Undertaking payable to DH. In addition to the principal payments, we have approximately $825 million of interest payments payable due over the remaining term of the Undertaking. Please read Note 1 Organization and Operations DMG Transfer and Note 20 Related Party Transactions Undertaking Agreement for further discussion.

Operating Leases. Operating leases includes the minimum lease payment obligations associated with office and office equipment leases.

Coal Commitments. At December 31, 2011, we had contracts in place to purchase coal from a subsidiary of DH for various of our generation facilities. The DH subsidiary has contracts with a third

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party for the purchase of this coal with minimum commitments of $433 million through 2015. In addition, we have obligations related to the transportation of the coal of $8 million through 2013.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations of $20 million, $16 million and $18 million for 2012, 2013 and 2014, respectively. Although we expect to continue to incur funding obligations subsequent to 2014, we cannot confidently estimate the amount of such obligations at this time and, therefore, have not included them in the table above. Please read Note 25 Employee Compensation, Savings and Pension Plans Pension and Other Post-Retirement Benefits Obligations and Funded Status for further discussion. A portion of these obligations are expected to be funded by DH through the Services Agreements.

Other Obligations. Other obligations includes a severance obligation of $1 million as of December 31, 2011 in connection with a reduction in workforce and the closure of certain power generation facilities. Please read Note 8 Impairment and Restructuring Charges Restructuring Charges for further discussion.

Contingent Financial Obligations Dynegy Inc.

The following table provides a summary of our contingent financial obligations as of December 31, 2011 on an undiscounted basis. The table does not include contingent financial obligations of DH and its subsidiaries, which are discussed in "Contingent Financial Obligations DH" below. The following obligations represent contingent obligations that may require a payment of cash upon the occurrence of specified events.

		Expiration by Period			
	Total	**Less than 1 Year**	**1 - 3 Years**	**3 - 5 Years**	**More than 5 Years**
		(in millions)			
Letters of credit (1)	$ 38	$ 38	$	$	$
Breakup fees (2)	27	27			
Guarantees (3)	41	18	23		
Total financial commitments	$ 106	$ 83	$ 23	$	$

(1) Amounts include outstanding letters of credit.

(2) The Breakup fees represent obligations to pay $16 million to The Blackstone Group and $11 million to Icahn Enterprises Holdings L.P. under certain circumstances. Please read Note 23 Commitments and Contingencies Other Commitments and Contingencies Blackstone Merger Agreement and Icahn Merger Agreement.

(3) Includes a Dynegy Inc. guarantee of $41 million for the VLGC leases as discussed in "Contractual Obligations DH" below. Please read Note 23 Commitments and Contingencies Guarantees and Indemnifications VLGC Guarantee for further discussion.

Contractual Obligations DH

The following table summarizes the contractual obligations of DH and its consolidated subsidiaries as of December 31, 2011. DH was deconsolidated effective November 7, 2011 and subsequently accounted for under the equity method of accounting. We have included the following disclosure

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because we believe it is meaningful to investors. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
			Expiration by Period (in millions)		
Debt subject to compromise	$ 3,570	$ 88	$	$ 1,832	$ 1,650
Interest payments on debt subject to compromise	1,763	278	548	409	528
Long-term debt (including current portion)	1,076	7	13	1,056	
Interest payments on debt	464	101	199	164	
Coal commitments (1)	449	179	184	86	
Operating leases	378	324	35	12	7
Capacity payments	257	39	78	55	85
Interconnection obligations	16	1	2	2	11
Construction service agreements	258	29	95	94	40
Other obligations	61	14	37	1	9
Total contractual obligations	$ 8,292	$ 1,060	$ 1,191	$ 3,711	$ 2,330

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

Long-Term Debt (Including Current Portion) Subject to Compromise. Total amounts of Long-term debt (including current portion) include approximately $3.5 billion in senior notes and debentures issued by DH that are subject to compromise in the bankruptcy process. Please read Note 3 Chapter 11 Cases for further discussion.

Interest Payments on Debt Subject to Compromise. Interest payments on debt subject to compromise represents periodic interest payment obligations associated with DH's senior notes and debentures and subordinated notes that are subject to compromise in the bankruptcy process. However, DH is not currently making interest payments on the debt due to its bankruptcy filing. Please read Note 3 Chapter 11 Cases for further discussion.

Long-Term Debt (Including Current Portion). Long-term debt includes amounts related to the DPC Credit Agreement. Please read Note 19 Debt DH Debt Obligations DPC Credit Agreement for further discussion.

Interest Payments on Debt. Interest payments on debt represent estimated periodic interest payment obligations associated with the DPC Credit Agreement. Please read Note 19 Debt DH Debt Obligations DPC Credit Agreement for further discussion.

Coal Commitments. At December 31, 2011, DH subsidiaries had contracts in place to purchase coal for various generation facilities. Obligations related to the purchase of the coal are $449 million through 2015. Approximately $433 million of the coal purchased under these contracts will be sold to DMG, an indirect wholly-owned subsidiary of Dynegy.

Operating Leases. Operating leases includes $300 million, which represents our best estimate of the amount of the allowed claim related to the termination of the DNE lease and is subject to compromise in the bankruptcy process. Please read Note 3 Chapter 11 Cases for further discussion. Operating leases also includes minimum lease payment obligations associated with office and office equipment leases.

In addition, a subsidiary of DH is party to two charter party agreements relating to two VLGCs previously utilized in our former global liquids business. The aggregate minimum base commitments of

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the charter party agreements are approximately $18 million for 2012 and approximately $23 million in aggregate for the period from 2013 through lease expiration. The charter party rates payable under the two charter party agreements vary in accordance with market-based rates for similar shipping services. The $18 million and $23 million amounts set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary terms of the charter party agreements expire September 2013 and September 2014, respectively. Both VLGCs have been sub-chartered to a wholly-owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. The subsidiary of DH relies on the sub-charters with a subsidiary of Transammonia to satisfy the obligations of the two charter party agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements.

Capacity Payments. Capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $257 million.

Interconnection Obligations. Interconnection obligations represent an obligation with respect to interconnection services for the Ontelaunee facility. This agreement expires in 2027. The obligation under this agreement is approximately $1 million per year through the term of the contract.

Construction Service Agreements. Construction service agreements represent obligations with respect to long-term plant maintenance agreements. The obligation under these agreements is approximately $258 million.

Other Obligations. Other obligations primarily include the following items:

- Demolition and restoration obligation associated with the South Bay facility of $37 million;
- Payments associated with a capacity contract between Independence and Con Edison. The aggregate payments through the 2014 expiration are approximately $6 million as of December 31, 2011;
- Obligations of $5 million for harbor support and utility work in connection with Moss Landing;
- Reserves of $4 million recorded in connection with uncertain tax positions. Please read Note 21 Income Taxes Unrecognized Tax Benefits for further discussion;
- Obligations of $3 million primarily for water supply agreement and other contracts in connection with Ontelaunee;
- Obligations of $2 million primarily for Morro Bay city improvements in connection with our Morro Bay facility;
- Obligations of $2 million related to information technology related contracts; and
- Severance and retention obligations of $2 million as of December 31, 2011 in connection with a reduction in workforce and the closure of certain power generation facilities. Please read Note 8 Impairment and Restructuring Charges Restructuring Charges for further discussion.

Contingent Financial Obligations DH

The following table provides a summary of the contingent financial obligations of DH and its consolidated subsidiaries as of December 31, 2011 on an undiscounted basis. These obligations represent contingent obligations that may require a payment of cash upon the occurrence of specified events. DH was deconsolidated effective November 7, 2011 and subsequently accounted for under the

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equity method accounting. We have included the following disclosure because we believe it is meaningful to investors.

	Expiration by Period				
	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
	(in millions)				
Letters of credit(1)	$ 412	$ 412	$	$	$
Surety bonds(2)	9	9			
Guarantees	2	2			
Total financial commitments	$ 423	$ 423	$	$	$

(1) Amount includes outstanding letters of credit.

(2) Surety bonds are generally on a rolling 12-month basis. The $9 million of surety bonds are primarily supported by collateral.

Commitments and Contingencies

Please read Note 23 Commitments and Contingencies, which is incorporated herein by reference, for further discussion of our material commitments and contingencies.

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RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the years ended December 31, 2011, 2010 and 2009. At the end of this section, we have included our business outlook for each segment.

As reflected in this report, we have changed our reportable segments. Prior to September 30, 2011, we reported results for the following segments: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Beginning with the third quarter 2011, as a result of the Reorganization in August 2011 our reportable segments are: (i) the Coal segment ("Coal"); (ii) the Gas segment ("Gas") and (iii) the Dynegy Northeast segment ("DNE"). Accordingly, we have recast the corresponding items of segment information for all prior periods. Our consolidated financial results also reflect corporate-level expenses such as interest and depreciation and amortization. General and administrative expenses are allocated to each reportable segment.

As a result of the Chapter 11 Cases, we deconsolidated our investment in DH and its wholly-owned subsidiaries as of November 7, 2011. Financial statement periods presented after November 7, 2011 reflect our investment in, and the results of operations of, DH and its wholly-owned subsidiaries under the equity method of accounting. For further discussion, please read Note 3 Chapter 11 Cases Accounting Impact.

Non-GAAP Performance Measures

In analyzing and planning for our business, we supplement our use of GAAP financial measures with non-GAAP financial measures, including EBITDA and Adjusted EBITDA. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed with our GAAP results and the accompanying reconciliations to corresponding GAAP financial measures included in the tables below, may provide a more complete understanding of factors and trends affecting our business. These non-GAAP financial measures should not be relied upon to the exclusion of GAAP financial measures and are by definition an incomplete understanding of Dynegy, and must be considered in conjunction with GAAP measures.

We believe that the historical non-GAAP measures disclosed in our filings are only useful as an additional tool to help management and investors make informed decisions about our financial and operating performance. By definition, non-GAAP measures do not give a full understanding of Dynegy; therefore, to be truly valuable, they must be used in conjunction with the comparable GAAP measures. In addition, non-GAAP financial measures are not standardized; therefore, it may not be possible to compare these financial measures with other companies' non-GAAP financial measures having the same or similar names. We strongly encourage investors to review our consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

EBITDA and Adjusted EBITDA. We define EBITDA as earnings (loss) before interest expense, income tax expense (benefit), and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA adjusted to exclude (i) gains or losses on the sale of assets, (ii) the impacts of mark-to-market changes on economic hedges related to our generation portfolio, and (iii) the impact of impairment charges and certain other costs such as those associated with the Reorganization, including those charges and costs embedded in losses from unconsolidated investments on our consolidated statements of operations. We believe EBITDA and Adjusted EBITDA provide a meaningful representation of our operating performance. We consider EBITDA as another way to measure financial performance on an ongoing basis. Adjusted EBITDA is meant to reflect the operating performance of our power generation fleet; consequently, it excludes the impact of mark-to-market accounting, impairment charges and gains and losses on sales of assets, and other items that could be considered "non-operating" or "non-core" in nature, and includes the contributions of those plants

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classified as discontinued operations. Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers and evaluate overall financial performance, we believe they provide useful information for our investors. In addition, many analysts, fund managers and other stakeholders that communicate with us typically request our financial results in an EBITDA and Adjusted EBITDA format.

As prescribed by the SEC, when Adjusted EBITDA is discussed in reference to performance on a consolidated basis, the most directly comparable GAAP financial measure to EBITDA and Adjusted EBITDA is net income (loss). Because management does not allocate interest expense and income taxes on a segment level, the most directly comparable GAAP financial measure to Adjusted EBITDA when performance is discussed on a segment level is Operating income (loss).

Consolidated Summary Financial Information Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

The following tables provide summary financial data regarding our consolidated and segmented results of operations for the years ended December 31, 2011 and 2010, respectively.

	Years Ended December 31,			
	2011	**2010**	**Change**	**% Change**
Revenues	$ 1,585	$ 2,323	$ (738)	(32)%
Cost of sales	(963)	(1,181)	218	18%
Gross margin, exclusive of depreciation shown separately below	622	1,142	(520)	(46)%
Operating and maintenance expense, exclusive of depreciation shown separately below	(393)	(450)	57	13%
Depreciation and amortization expense	(325)	(392)	67	17%
Impairment and other charges	(6)	(148)	142	96%
Gain on sale of assets	1		1	100%
General and administrative expenses	(135)	(163)	28	17%
Operating loss	(236)	(11)	(225)	(2,045)%
Losses from unconsolidated investments		(62)	62	100%
Loss on deconsolidation of DH	(1,657)		(1,657)	(100)%
Interest expense	(357)	(363)	6	2%
Debt extinguishment costs	(21)		(21)	(100)%
Other income and expense, net	(6)	4	(10)	(250)%
Loss from continuing operations before income taxes	(2,277)	(432)	(1,845)	(427)%
Income tax benefit	632	197	435	221%
Loss from continuing operations	(1,645)	(235)	(1,410)	(600)%
Income from discontinued operations, net of taxes		1	(1)	(100)%
Net loss	$ (1,645)	$ (234)	$ (1,411)	(603)%

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The following tables provide summary financial data regarding our operating income (loss) by segment for the years ended December 31, 2011 and 2010, respectively:

	Year Ended December 31, 2011				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Revenues	$ 658	$ 828	$ 101	$ (2)	$ 1,585
Cost of sales	(338)	(560)	(63)	(2)	(963)
Gross margin, exclusive of depreciation shown separately below	320	268	38	(4)	622
Operating and maintenance expense, exclusive of depreciation shown separately below	(170)	(124)	(98)	(1)	(393)
Depreciation and amortization expense	(206)	(114)		(5)	(325)
Impairment and other charges			(2)	(4)	(6)
Gain on sale of assets, net			1		1
General and administrative expenses	(45)	(49)	(9)	(32)	(135)
Operating loss	$ (101)	$ (19)	$ (70)	$ (46)	$ (236)

	Year Ended December 31, 2010				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Revenues	$ 836	$ 1,223	$ 264	$	$ 2,323
Cost of sales	(355)	(707)	(121)	2	(1,181)
Gross margin, exclusive of depreciation shown separately below	481	516	143	2	1,142
Operating and maintenance expense, exclusive of depreciation shown separately below	(175)	(153)	(120)	(2)	(450)
Depreciation and amortization expense	(256)	(135)	5	(6)	(392)
Impairment and other charges	(4)	(136)	(2)	(6)	(148)
General and administrative expenses	(52)	(69)	(15)	(27)	(163)
Operating income (loss)	$ (6)	$ 23	$ 11	$ (39)	$ (11)

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The following tables provide summary financial data regarding our Adjusted EBITDA by segment for the years ended December 31, 2011 and 2010, respectively.

	Year Ended December 31, 2011				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Net loss					$ (1,645)
Income tax benefit					(632)
Interest expense and debt extinguishment costs					378
Loss on deconsolidation of DH					1,657
Other items, net					6
Operating income (loss)	$ (101)	$ (19)	$ (70)	$ (46)	$ (236)
Other items, net	1	1		(8)	(6)
Depreciation and amortization expense	206	114		5	325
Loss on deconsolidation of DH				(1,657)	(1,657)
EBITDA	106	96	(70)	(1,706)	(1,574)
Merger agreement termination fee, restructuring costs and other expenses	7	13		25	45
Mark-to-market losses, net	91	34	46	4	175
Loss on deconsolidation of DH				1,657	1,657
Impairment of note from DH				10	10
Deconsolidated Adjusted EBITDA	204	143	(24)	(10)	313
Adjustment to include adjusted EBITDA from unconsolidated investments(1)		(43)	(4)	15	(32)
Pre-Deconsolidation Adjusted EBITDA	$ 204	$ 100	$ (28)	$ 5	$ 281

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(1) Effective November 7, 2011, we deconsolidated our investment in DH. As a result, the results of our Gas and DNE segment, as well as certain items in the Other segment, were not included in our consolidated results. We did not include any losses from our unconsolidated investment in DH for the period from November 8, 2011 through December 31, 2011 because to do so would have reduced our investment below zero and we do not have an obligation to fund such losses. However, we have included the adjusted EBITDA from our investment in this adjustment because management uses Adjusted EBITDA to focus on the operating performance of our entire power generation fleet. A reconciliation of Adjusted EBITDA to Operating income (loss) for the investment is presented below:

	November 8, 2011 through December 31, 2011			
	Gas	DNE	Other	Total
	(in millions)			
Operating income (loss)	$ (80)	$ (5)	$ 9	$ (76)
Depreciation and amortization expense	17	(6)	1	12
EBITDA	(63)	(11)	10	(64)
Mark-to-market losses, net	17			17
Restructuring charges	3		5	8
DNE lease adjustment		7		7
Adjusted EBITDA	$ (43)	$ (4)	$ 15	$ (32)

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	Year Ended December 31, 2010				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Net loss					$ (234)
Income tax benefit					(197)
Interest expense					363
Losses from unconsolidated investments					62
Income from discontinued operations, net of taxes					(1)
Other items, net					(4)
Operating income (loss)	$ (6)	$ 23	$ 11	$ (39)	$ (11)
Other items, net		2		2	4
Depreciation and amortization expense	256	135	(5)	6	392
Losses from unconsolidated investments				(62)	(62)
EBITDA from continuing operations	250	160	6	(93)	323
EBITDA from discontinued operations		1			1
EBITDA	250	161	6	(93)	324
Impairments		134	2	37	173
Loss on sale of PPEA Holding				28	28
Merger agreement transaction costs				26	26
Restructuring charges	4	2		6	12
Plum Point mark-to-market gains				(6)	(6)
Mark-to-market (gains) losses, net	(21)	11	(18)	10	(18)
Adjusted EBITDA	$ 233	$ 308	$ (10)	$ 8	$ 539

Discussion of Consolidated Results of Operations

Revenues. Revenues decreased by $738 million from $2,323 million for the year ended December 31, 2010 to $1,585 million for the year ended December 31, 2011. Of this decrease, approximately $50 million relates to the deconsolidation of DH, including the results of the Gas and DNE segments, effective November 7, 2011. The remaining decrease of $688 million is primarily due to:

- Approximately $183 million related to the difference between mark-to-market losses on forward sales of power and other derivatives in 2011, compared to mark-to-market gains in 2010. Such losses totaled $162 million for the year ended December 31, 2011, compared to $21 million of mark-to-market gains for the year ended December 31, 2010. The mark-to-market losses for the year ended December 31, 2011 included fees of approximately $8 million paid to brokers in connection with the Reorganization.

- Approximately $505 million related to lower generated volumes and market prices as well as less revenue from capacity sales, RMR agreements, option premiums and the financial settlement of derivative instruments, as further described below.

Cost of Sales. Cost of sales decreased by $218 million from $1,181 million for the year ended December 31, 2010 to $963 million for the year ended December 31, 2011. Of this decrease, approximately $70 million relates to the deconsolidation of DH, including the results of the Gas and DNE segments, effective November 7, 2011. The remaining decrease of approximately $148 million is due to lower generated volumes and lower gas and coal prices, as further described below.

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. Operating and maintenance expense decreased by $57 million from $450 million for the year ended December 31, 2010 to $393 million for the year ended December 31, 2011. Of this decrease, approximately

$36 million relates to the deconsolidation of DH, including the results of the Gas and DNE segments, effective November 7, 2011. The remaining decrease of approximately $21 million is due to the mothballing and subsequent retirement of the Vermilion facility in 2011, the retirement of the South Bay facility in late 2010 and a curtailment gain due to a change in Dynegy's post retirement benefit plan in 2011.

Depreciation and Amortization Expense. Depreciation expense decreased by $67 million from $392 million for the year ended December 31, 2010 to $325 million for the year ended December 31, 2011. Of this decrease, approximately $12 million relates to the deconsolidation of DH, including the results of the Gas and DNE segments, effective November 7, 2011. The remaining decrease of approximately $55 million was largely due to fully depreciating the value of our Vermilion facility in the first quarter 2011, fully depreciating the value of Wood River Units 1-3 and Havana Units 1-5 in September 2010, as well as the Havana 6 Precipitator Rebuild retirement in 2010. In addition, depreciation expense was reduced by $16 million in 2011 as a result of downward revisions to ARO obligations on assets that are fully depreciated. The ARO revisions relate to updated cost estimates for asbestos remediation.

Impairment and Other Charges. Impairment and other charges for the year ended December 31, 2011 includes $4 million in restructuring charges and $2 million in impairment charges related to the Roseton and Danskammer facilities prior to the deconsolidation of DH. Impairment and other charges for the year ended December 31, 2010 included a pre-tax asset impairment of $134 million related to our Casco Bay power generation facility and related assets and $12 million related to severance charges for a reduction in workforce and the closure of our Vermilion and South Bay facilities. Please read Note 8 Impairment and Restructuring Charges for further discussion.

General and Administrative Expenses. General and administrative expenses decreased $28 million from $163 million for the year ended December 31, 2010 to $135 million for the year ended December 31, 2011. Of this decrease, approximately $7 million relates to the deconsolidation of DH, including the results of the Gas and DNE segments, effective November 7, 2011. The remaining decrease of approximately $21 million was primarily driven by lower salary and benefits costs as a result of ongoing cost savings initiatives, and a reduction in the value of cash-settled stock-based compensation instruments. These savings were partially offset by $4 million of executive severance costs and $15 million of restructuring costs in 2011.

Losses from Unconsolidated Investments. In 2011, we did not record any losses from our unconsolidated investment in DH because to do so would have reduced our investment in DH below zero and we do not have an obligation to fund such losses. Please read Note 3 Chapter 11 Cases for further discussion of the deconsolidation and Note 15 Unconsolidated Investments DH for further discussion of the losses incurred by DH subsequent to its deconsolidation.

Losses from unconsolidated investments for the year ended December 31, 2010 were $62 million related to our former investment in PPEA Holding. The losses consisted of $28 million related to the loss on sale of PPEA Holding, sold in the fourth quarter of 2010, and 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. Our investment in PPEA Holding was fully impaired at March 31, 2010 due to the uncertainty regarding PPEA's financing structure. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion.

Loss on Deconsolidation of DH. Loss on deconsolidation for the year ended December 31, 2011 relates to the deconsolidation of DH effective November 7, 2011. Upon deconsolidation, we recorded our investment in DH at its estimated fair value of zero on November 7, 2011, resulting in a loss of $1,657 million. Please read Note 3 Chapter 11 Cases Accounting Impact for further discussion.

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Interest Expense. Interest expense totaled $357 million and $363 million for the years ended December 31, 2011 and 2010, respectively. Of this decrease, approximately $10 million relates to the deconsolidation of DH effective November 7, 2011. The decrease related to the deconsolidation would have been larger, except that DH ceased accruing interest related to its unsecured notes and debentures as a result of the commencement of the Chapter 11 Cases effective November 7, 2011. This decrease was partially offset by the higher borrowings and rates under the DMG Credit Agreement and the DPC Credit Agreement (through November 7, 2011) compared to DH's prior Fifth Amended and Restated Credit Agreement.

Debt Extinguishment Costs. Debt extinguishment costs totaled $21 million for the year ended December 31, 2011 and were incurred in connection with the termination of the Sithe senior debt. Please read Note 19 Debt DH Debt Obligations Sithe Senior Notes for further discussion.

Other income and expense, net. Other income and expense, net totaled a loss of $6 million for the year ended December 31, 2011 compared to income of $4 million for the year ended December 31, 2010. The decrease of $10 million is duethe impairment of a note receivable from DH in 2011. Please read Note 20 Related Party Transactions Transactions with DH Note receivable, affiliate for further discussion.

Income Tax Benefit. We reported an income tax benefit from continuing operations of $632 million for the year ended December 31, 2011, compared to an income tax benefit from continuing operations of $197 million for the year ended December 31, 2010. The effective tax rate in 2011 was 28 percent, compared to 46 percent in 2010.

For the year ended December 31, 2011, the difference between the effective rate of 28 percent and the statutory rate of 35 percent resulted primarily as a result of the recognition of a deferred tax asset associated with our basis in the stock of DH due to the deconsolidation of DH and the impact of state taxes partially offset by a change in our valuation allowance. For the year ended December 31, 2010, the difference between the effective rate of 46 percent and the statutory rate of 35 percent resulted primarily from a benefit of $18 million related to the release of reserves for uncertain tax positions, partially offset by the impact of state taxes.

Adjusted EBITDA. Adjusted EBITDA decreased by $258 million from $539 million for the year ended December 31, 2010, to $281 million for the year ended December 31, 2011, primarily due to a $123 million decrease in premium revenue due to fewer options sold in 2011, a $31 million decrease in energy margins, $50 million in lower capacity revenues in all markets, and a $34 million loss related to commercial activity in the fourth quarter 2011. These decreases were partially offset by lower operating costs.

The decrease in energy margins and capacity revenues was due to lower generated volumes resulting primarily from outages, lower spark spreads and the mothballing and subsequent retirement of the Vermilion facility and the retirement of the South Bay facility. Additionally, overall market prices and capacity prices were lower in 2011 compared to 2010. Operating expense decreased due to the mothballing and subsequent retirement of the Vermilion facility and the retirement of the South Bay facility and general and administrative expense decreased due to a reduction in head count.

Discussion of Segment Results of Operations

Coal Segment. Power prices were slightly lower in 2011 compared to 2010. On-peak prices were lower in 2011 compared to 2010, which was partly offset by higher off-peak prices in 2011 compared to 2010.

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The following table provides summary financial data regarding our Coal segment results of operations for the years ended December 31, 2011 and 2010, respectively:

	Year Ended December 31,			
	2011	2010	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$ 679	$ 699	$ (20)	(3)%
Capacity	9	17	(8)	(47)%
Financial transactions:				
Mark-to-market income (loss)	(91)	21	(112)	(533)%
Financial settlements	58	97	(39)	(40)%
Option premiums	7	7		
Total financial transactions	(26)	125	(151)	(121)%
Other(1)	(4)	(5)	1	20%
Total revenues	658	836	(178)	(21)%
Cost of sales	(338)	(355)	17	5%
Gross margin	$ 320	$ 481	$ (161)	(33)%
Million Megawatt Hours Generated	22.2	22.3	(0.1)	
In Market Availability for Coal Fired Facilities(2)	92%	91%		
Average Quoted On-Peak Market Power Prices ($/MWh)(3):				
Cinergy (Cin Hub)	$ 41	$ 42	$ (1)	(2)%

(1) Other includes ancillary services and other miscellaneous items.

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

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

Gross margin from the Coal segment decreased by $161 million from $481 million for the year ended December 31, 2010, to $320 million for the year ended December 31, 2011. This decrease was driven by the following:

- Mark-to-market revenue decreased by $112 million due to a net change from mark-to-market revenue from $21 million in 2010 to a mark-to-market loss of $91 million in 2011. This decrease was driven by prices falling more sharply in 2010 as compared to 2011.

- Settlements revenue decreased by $39 million due to fewer volumes hedged in 2011 compared to 2010. Settlements revenue also decreased due to the average value of our hedging positions being lower in 2011 compared to 2010.

- Capacity revenue decreased by $8 million due to lower capacity prices in the MISO capacity market in 2011 compared to 2010.

Energy revenue and the corresponding cost of sales decreased by $20 million and $17 million, respectively, for a net decrease in energy margin of $3 million. Energy revenue and cost of sales decreased due to lower on-peak power prices in the MISO market and lower coal pricing as well as slightly lower generation.

Our average coal price decreased primarily due to the mothballing and subsequent retirement of the Vermilion facility as Vermilion had a higher delivered fuel cost. Delivered coal prices declined in late 2010 as a result of competing requirements under a higher priced contract prior

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to the end of the year. This also impacted the weighted average cost of coal in 2011 and resulted in lower burn expense during the early portion of 2011. While net volumes burned remained relatively flat, costs per ton declined in 2011.

Generation volumes decreased slightly year over year. Volumes were reduced due to the mothballing and subsequent retirement of the Vermilion facility. The decrease in volumes caused by the Vermilion retirement was largely offset by an increase in volumes at Baldwin caused by fewer outages in 2011 compared to 2010. In early 2010, Baldwin experienced a three month outage that reduced burns for 2010. While Baldwin did experience outages in 2011, they were not as significant as those in 2010.

Gas Segment. Spark-spreads in the Northeast were somewhat mixed in 2011 with improved spark-spreads in the first quarter offset by lower spark-spreads in the third quarter. Additionally, net generated volumes were lower at Casco Bay in 2011 compared to 2010 due to planned and unplanned outages. In PJM, net generated volumes were higher driven primarily by positive off-peak spark-spreads at Ontelaunee.

For the California facilities, spark-spreads were down in 2011 as compared to 2010. Robust snowpack in the Northwest United States and California led to strong hydro production; the Northwest United States recorded the second greatest hydro production since 1993. This coupled with a very mild summer, led to historical low spark-spreads. Generated volumes were down significantly due to competition with hydro generation as well as an unplanned outage.

The following table provides summary financial data regarding our Gas segment results of operations for the years ended December 31, 2011 and 2010, respectively. The Gas segment results for

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2011 only include the results of operations through November 7, 2011, the date that segment was deconsolidated. Please read Note 3 Chapter 11 Cases for further discussion.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$ 431	$ 619	$ (188)	(30)%
Capacity	181	231	(50)	(22)%
RMR	5	45	(40)	(89)%
Tolls	112	137	(25)	(18)%
Natural gas	182	169	13	(8)%
Financial transactions:				
Mark-to-market losses	(16)	(11)	(5)	(45)%
Financial settlements	(117)	(117)		
Option premiums	18	127	(109)	(86)%
Total financial transactions	(115)	(1)	(114)	(11,400)%
Other(1)	32	23	9	(39)%
Total revenues	828	1,223	(395)	(32)%
Cost of sales	(560)	(707)	147	21%
Gross margin	$ 268	$ 516	$ (248)	(48)%
Million Megawatt Hours Generated(2)	12.3	14.2	(1.9)	(13)%
Average Capacity Factor for Combined Cycle Facilities(3)	31%	36%		
Average Quoted On-Peak Market Power Prices ($/MWh)(4):				
Commonwealth Edison (NI Hub)	$ 41	$ 41	$	
PJM West	$ 51	$ 54	$ (3)	(6)%
North Path 15 (NP 15)	$ 36	$ 40	$ (4)	(10)%
New York Zone A	$ 42	$ 44	$ (2)	(5)%
Mass Hub	$ 53	$ 56	$ (3)	(5)%
Average Market Spark Spreads ($/MWh)(5):				
PJM West	$ 19	$ 19	$	
North Path 15 (NP 15)	$ 4	$ 6	$ (2)	(33)%
New York Zone A	$ 9	$ 9	$	
Mass Hub	$ 18	$ 18	$	
Average natural gas price Henry Hub ($/MMBtu)(6)	$ 3.99	$ 4.38	$ (0.39)	(9)%

(1) Other includes ancillary services and other miscellaneous items.

(2) Includes hours generated for the full year 2011 and 2010 and also includes DH's ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility.

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

(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 or an 11.0 MMBtu/MWh heat rate fuel oil-fired 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) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

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Gross margin for the Gas segment decreased by $248 million from $516 million for the year ended December 31, 2010, to $268 million for the year ended December 31, 2011. There is approximately $26 in negative gross margin that is not included in 2011 results as a result of the deconsolidation. The decrease of $248 was driven by the following:

Premium revenue decreased by $109 million due to fewer options sold and fewer premiums collected in 2011 compared to 2010 due to a decline in price volatilities. Market volatilities have been in decline for the past two years, reducing the value of options on a unit basis and diminishing the revenue opportunities from their sale. Additionally, fewer option sales have resulted from our strategy of leaving more of our portfolio open to a market recovery expected over the next few years while we opportunistically hedge short-term cash flows.

Energy revenue and the corresponding cost of sales decreased by $188 million and $147 million, respectively, for a net decrease in energy margin of $41 million. Energy revenue and cost of sales decreased due to lower market pricing across the region and lower volumes generated. Volumes were down due to lower spark spreads at Moss Landing and Casco Bay in 2011 compared to 2010. Volumes were also down due to more outages at Moss Landing and Casco Bay in 2011 compared to 2010. Both plants experienced significant outages in 2011 due to required turbine blade repairs. These decreases were partially offset by increases in volumes at Kendall and Ontelaunee which both saw an increase in generation volumes due to fewer outages and derates in 2011 compared to 2010 as well as improved spark spreads in 2011.

RMR revenue decreased by $40 million due to the expiration of the South Bay RMR agreement. The CAISO elected not to renew the agreement for 2011 and the facility was permanently retired on December 31, 2010.

Capacity revenue decreased by $50 million due to lower capacity prices in the NYISO, PJM and Mass Hub markets in 2011 compared to 2010. Capacity prices have decreased significantly year over year due to excess capacity in the market.

Tolling revenue decreased by $25 million due to the termination of the Kendall Constellation toll in 2010. In connection with the termination of the Kendall toll in 2010, we received a termination payment which was not repeated in 2011. The decrease from the 2010 cancellation payment was partially offset by higher revenues from the Moss Landing toll which was renewed with higher rates for 2011.

Gas revenue increased by $13 million due to an increase in volumes sold in 2011 compared to 2010. The increase in volumes sold is due to lower 2011 power generation primarily at Independence. The decrease in power generation made more gas available to be sold back to the market as it was not required for production.

Other revenue increased by $9 million primarily due to an increase in ancillary pricing in the PJM market and increased 2011 off-peak generation at Ontelaunee which provided the opportunity to supply more ancillary services.

DNE Segment. Average spark spreads have stayed flat year over year. During the year, dark spreads at Danskammer were compressed by lower Zone G prices and increased coal prices. These compressed spark spreads more than offset the increases in spreads from earlier in the year. In addition, increased imports from the NE-ISO impacted our results.

The following table provides summary financial data regarding our DNE segment results of operations for the years ended December 31, 2011 and 2010, respectively. The DNE segment results

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for 2011 only include the results of operations through November 7, 2011, the date that segment was deconsolidated. Please read Note 3 Chapter 11 Cases for further discussion.

	Year Ended December 31, 2011	Year Ended December 31, 2010	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$ 93	$ 142	$ (49)	(35)%
Capacity	15	41	(26)	(63)%
Financial transactions:				
Mark-to-market income (loss)	(46)	18	(64)	(356)%
Financial settlements	33	32	1	3%
Option premiums	2	7	(5)	(71)%
Total financial transactions	(11)	57	(68)	(119)%
Other(1)	4	24	(20)	(83)%
Total revenues	101	264	(163)	(62)%
Cost of sales	(63)	(121)	58	48%
Gross margin	$ 38	$ 143	$ (105)	(73)%
Million Megawatt Hours Generated(2)	1.2	2.2	(1.0)	(45)%
In Market Availability for Coal Fired Facilities(3)	94%	95%		
Average Capacity Factor Coal	28%	53%		
Average Capacity Factor Gas	3%	4%		
Average Quoted On-Peak Market Power Prices ($/MWh)(4):				
New York Zone G	$ 57	$ 59	$ (2)	(3)%
Average Market Spark Spreads ($/MWh)(5):				
Fuel Oil	$ (121)	$ (72)	$ (49)	(68)%

(1) Other includes ancillary services and other miscellaneous items.

(2) Includes hours generated for the full year 2011 and 2010.

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

(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 or an 11.0 MMBtu/MWh heat rate fuel oil-fired 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.

Gross margin for the DNE segment decreased by $105 million from $143 million for the year ended December 31, 2010, to $38 million for the year ended December 31, 2011. The decrease was driven by the following:

Approximately $2 million of the decrease is due to the deconsolidation of DH effective November 7, 2011.

Mark-to-market revenue decreased by $64 million due to a net change in mark-to-market revenue of $18 million in 2010 to a mark-to-market loss of $46 million in 2011.

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Capacity revenue decreased by $26 million due to lower capacity prices in the NYISO capacity market in 2011 compared to 2010.

Other revenue decreased by $20 million primarily due to the 2010 sale of Roseton fuel oil. There were no corresponding fuel oil sales in 2011.

Energy revenue and the corresponding cost of sales both decreased by $49 million and $58 million, respectively, for a net increase in energy margin of $9 million. Energy revenue and cost of sales decreased due to lower volumes generated. The decrease in volumes is due to the cycling of units at Danskammer and economic conditions. Danskammer began cycling units D3 and D4 to reduce generation in non-profitable off-peak hours which has decreased generation volumes but increased the average price per MWh sold. Volumes were also down due to generation costs associated with Roseton and Danskammer being higher than what could have been realized in the market for longer periods of time in 2011 compared to 2010. Also impacting Roseton volumes in 2010, was a third party nuclear facility located in the Northeast that was down for an extended period which resulted in Roseton being dispatched more in 2010 compared to 2011.

Consolidated Summary Financial Information   Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The following tables provide summary financial data regarding our consolidated and segmented results of operations for the years ended December 31, 2010 and 2009, respectively.

	Years Ended December 31,			
	2010	**2009**	**Change**	**% Change**
Revenues	$ 2,323	$ 2,468	$ (145)	(6)%
Cost of sales	(1,181)	(1,194)	13	1%
Gross margin, exclusive of depreciation shown separately below	1,142	1,274	(132)	(10)%
Operating and maintenance expense, exclusive of depreciation shown separately below	(450)	(519)	69	13%
Depreciation and amortization expense	(392)	(335)	(57)	(17)%
Goodwill impairment		(433)	433	100%
Impairment and other charges	(148)	(538)	390	72%
Loss on sale of assets, net		(124)	124	100%
General and administrative expenses	(163)	(159)	(4)	(3)%
Operating loss	(11)	(834)	823	99%
Losses from unconsolidated investments	(62)	(71)	9	13%
Interest expense	(363)	(415)	52	13%
Debt extinguishment costs		(46)	46	100%
Other income and expense, net	4	11	(7)	(64)%
Loss from continuing operations before income taxes	(432)	(1,355)	923	68%
Income tax benefit	197	315	(118)	(37)%
Loss from continuing operations	(235)	(1,040)	805	77%
Income (loss) from discontinued operations, net of taxes	1	(222)	223	100%
Net loss	(234)	(1,262)	1,028	81%
Less: Net loss attributable to noncontrolling interests		(15)	15	100%
Net loss attributable to Dynegy Inc.	$ (234)	$ (1,247)	$ 1,013	81%

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The following tables provide summary financial data regarding our operating income (loss) by segment for the years ended December 31, 2010 and 2009, respectively:

	Year Ended December 31, 2010				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Revenues	$ 836	$ 1,223	$ 264	$	$ 2,323
Cost of sales	(355)	(707)	(121)	2	(1,181)
Gross margin, exclusive of depreciation shown separately below	481	516	143	2	1,142
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(175)	(153)	(120)	(2)	(450)
Depreciation and amortization expense	(256)	(135)	5	(6)	(392)
Impairment and other charges	(4)	(136)	(2)	(6)	(148)
General and administrative expenses	(52)	(69)	(15)	(27)	(163)
Operating income (loss)	$ (6)	$ 23	$ 11	$ (39)	$ (11)

	Year Ended December 31, 2009				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Revenues	$ 940	$ 1,260	$ 273	$ (5)	$ 2,468
Cost of sales	(345)	(716)	(134)	1	(1,194)
Gross margin, exclusive of depreciation shown separately below	595	544	139	(4)	1,274
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(182)	(217)	(123)	3	(519)
Depreciation and amortization expense	(161)	(148)	(8)	(18)	(335)
Goodwill impairments		(433)			(433)
Impairment and other charges	(42)	(284)	(212)		(538)
Loss on sale of assets, net	(6)	(118)			(124)
General and administrative expenses	(49)	(96)	(13)	(1)	(159)
Operating income (loss)	$ 155	$ (752)	$ (217)	$ (20)	$ (834)

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The following tables provide summary financial data regarding our Adjusted EBITDA by segment for the years ended December 31, 2010 and 2009, respectively.

	Year Ended December 31, 2010				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Net loss.					$ (234)
Income tax benefit					(197)
Interest expense					363
Losses from unconsolidated investments					62
Income from discontinued operations, net of taxes					(1)
Other items, net					(4)
Operating income (loss)	$ (6)	$ 23	$ 11	$ (39)	$ (11)
Other items, net		2		2	4
Depreciation and amortization expense	256	135	(5)	6	392
Losses from unconsolidated investments				(62)	(62)
EBITDA from continuing operations	250	160	6	(93)	323
EBITDA from discontinued operations		1			1
EBITDA	250	161	6	(93)	324
Impairments		134	2	37	173
Loss on sale of PPEA Holding				28	28
Merger agreement transaction costs				26	26
Restructuring charges	4	2		6	12
Plum Point mark-to-market gains				(6)	(6)
Mark-to-market (gains) losses, net	(21)	11	(18)	10	(18)
Adjusted EBITDA	$ 233	$ 308	$ (10)	$ 8	$ 539

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	Year Ended December 31, 2009				
	Coal	Gas	DNE	Other	Total
	(in millions)				
Net loss attributable to Dynegy Inc					$ (1,247)
Income tax benefit					(315)
Interest expense					461
Losses from unconsolidated investments					71
Loss from discontinued operations, net of taxes					222
Net loss attributable to noncontrolling interests					(15)
Other items, net					(11)
Operating income (loss)	$ 155	$ (752)	$ (217)	$ (20)	$ (834)
Other items, net	2	2		7	11
Depreciation and amortization expense	161	148	8	18	335
Losses from unconsolidated investments				(71)	(71)
Net loss attributable to noncontrolling interests				15	15
EBITDA from continuing operations	318	(602)	(209)	(51)	(544)
EBITDA from discontinued operations		(328)			(328)
EBITDA	318	(930)	(209)	(51)	(872)
Goodwill impairments		433			433
Impairments and other charges	42	542	212		796
Loss on LS Power transactions	6	222			228
Gain on sale of Heard County		(10)			(10)
Loss on sale of Sandy Creek				84	84
Sandy Creek mark-to-market gains				(21)	(21)
Net loss attributable to noncontrolling interests				(15)	(15)
Mark-to-market (gains) losses, net	108	128	(31)	(25)	180
Adjusted EBITDA	$ 474	$ 385	$ (28)	$ (28)	$ 803

Discussion of Consolidated Results of Operations

Revenues. Revenues decreased by $145 million from $2,468 million for the year ended December 31, 2009 to $2,323 million for the year ended December 31, 2010. Of this decrease $386 million related to less revenue generated from the financial settlement of derivative instruments. The decrease from financial settlements was partially offset by an increase of $201 million in mark-to-market revenue from forward sales of power and other derivatives. Such gains totaled $21 million for the year ended December 31, 2010, compared to $180 million in mark-to-market losses for the year ended December 31, 2009.

The decrease from financial settlements was further offset by increases from gas sales, RMR agreements and ancillary services which in turn were offset by decreases from capacity sales and tolling agreements, as further described below.

Cost of Sales. Cost of sales decreased by $13 million from $1,194 million for the year ended December 31, 2009 to $1,181 million for the year ended December 31, 2010. This decrease is primarily due to lower generated volumes, as further described below.

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. Operating and maintenance expense decreased by $69 million from $519 million for the year ended December 31, 2009 to $450 million for the year ended December 31, 2010. This decrease is due to the sale of the Bridgeport facility and other facilities to LS Power in the fourth quarter 2009 and lower 2010 outage costs.

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Depreciation and Amortization Expense. Depreciation expense increased by $57 million from $335 million for the year ended December 31, 2009 to $392 million for the year ended December 31, 2010. The increase was largely due to accelerating the depreciation of our Vermilion facility which was mothballed in the first quarter 2011 and subsequently retired. In addition, capital projects associated with the Consent Decree and early retirement of Wood River units 1-3 and Havana units 1-5 also increased depreciation expense. These increases were partly offset by the impact of the sale of certain assets to LS Power in the fourth quarter of 2009 and the impairment of our Roseton and Danskammer power generation facilities in 2009.

Goodwill impairments. Goodwill impairments for the year ended December 31, 2009 included a pre-tax impairment of $433 million. Please read Note 17 Goodwill for further discussion.

Impairment and Other Charges. Impairment and other charges for the year ended December 31, 2010 included a pre-tax asset impairment of $134 million related to our Casco Bay power generation facility and related assets. Impairment and other charges for the year ended December 31, 2009 included pre-tax asset impairments of $538 million related to multiple power generation facilities. Please read Note 8 Impairment and Restructuring Charges for further discussion.

Loss on Sale of Assets. Loss on sale of assets for the year ended December 31, 2009 included a $124 million loss on the closing of the LS Power Transactions. Please read Note 5 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further discussion.

General and Administrative Expenses. General and administrative expenses increased $4 million from $159 million for the year ended December 31, 2009 to $163 million for the year ended December 31, 2010. General and administrative expenses for the year ended December 31, 2010 included $26 million of Blackstone Merger Agreement and Icahn Merger Agreement costs and $9 million of legal expenses, partially offset by reduced costs in 2010 associated with our company-wide cost savings program compared to 2009.

Losses from Unconsolidated Investments. Losses from unconsolidated investments were $62 million related to our former investment in PPEA Holding. The losses consisted of $28 million related to the loss on sale of PPEA Holding, sold in the fourth quarter of 2010, and 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. Our investment in PPEA Holding was fully impaired at March 31, 2010 due to the uncertainty regarding PPEA's financing structure.

Losses from unconsolidated investments were $71 million for the year ended December 31, 2009. The loss included a loss of $84 million on the sale of our investment in the Sandy Creek Project to LS Power partially offset by equity earnings of $12 million. Please read Note 5 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further discussion. In addition, we recorded $1 million of earnings related to our former investment in DLS Power Development, included in Other.

Other Items, Net. Other items, net, totaled $4 million of income for December 31, 2010, compared to $11 million of income for the year ended December 31, 2009. The decrease is primarily associated with insurance proceeds received in 2009 and with lower interest income due to lower cash and restricted cash balances in 2010.

Interest Expense. Interest expense and debt extinguishment costs totaled $363 million for the year ended December 31, 2010, compared to $461 million for the year ended December 31, 2009. The decrease was primarily attributable to lower outstanding debt in 2010 and $46 million of debt extinguishment costs in 2009 due to the December 2009 repurchase of $833 million in aggregate

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principal amount of our senior unsecured notes as well as the deconsolidation and subsequent sale of our interest in PPEA Holding in 2010. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion. 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 to DH's Fifth Amended and Restated Credit Agreement in August 2009.

Income Tax Benefit. We reported an income tax benefit from continuing operations of $197 million for the year ended December 31, 2010, compared to an income tax benefit from continuing operations of $315 million for the year ended December 31, 2009. The 2010 effective tax rate was 46 percent, compared to 23 percent in 2009.

The difference between the statutory rate of 35 percent and the effective rate of 46 percent for the year ended December 31, 2010 resulted primarily from the benefit of $18 million resulting from the release of a reserve for uncertain tax positions upon completion of a federal income tax audit together with an overall state tax benefit resulting from current year losses, changes in our state sales profile and a benefit of $12 million resulting from a change in California state tax law.

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

Discontinued Operations

Loss From Discontinued Operations Before Taxes. For the year ended December 31, 2010, our pre-tax income from discontinued operations was $1 million. For the year ended December 31, 2009, our pre-tax loss from discontinued operations was $343 million ($222 million after-tax), related to the operation of our Arizona, Bluegrass and Heard County facilities. Our Gas segment included pre-tax impairment charges of $235 million ($143 million after-tax) related to our Arizona power generation facilities and a pre-tax loss of $82 million ($50 million after-tax) on the completion of the LS Power Transactions. Additionally, the Gas segment included a pre-tax gain on sale of $10 million ($6 million after-tax) related to our Heard County power generation facility. Our Gas segment included pre-tax impairment charges of $23 million ($14 million after-tax) related to our Bluegrass power generating facility and a pre-tax loss on the completion of the LS Power Transactions of $22 million ($13 million after-tax) .

Income Tax Benefit From Discontinued Operations. We recorded an income tax benefit from discontinued operations of $121 million during the year ended December 31, 2009. This amount reflects an effective rate of 35 percent.

Noncontrolling Interest. We recorded $15 million of noncontrolling interest losses for the year ended December 31, 2009, related to our investment in PPEA Holding. On January 1, 2010, we adopted ASU No. 2009-17. The adoption of ASU No. 2009-17 resulted in a deconsolidation of our investment in PPEA Holding which was accounted for as an equity method investment until the sale of our interest in PPEA Holding on November 10, 2010. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion.

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Adjusted EBITDA. Adjusted EBITDA decreased by $264 million from $803 million for the year ended December 31, 2009 to $539 million for the year ended December 31, 2010, primarily due to lower value received from the financial settlement of derivative instruments in 2010 compared to 2009.

Discussion of Segment Results of Operations

Coal Segment. Power prices in 2010 were higher than in 2009 for both on- and off-peak throughout the year with the exception of a few months. The summer season saw the largest disparity between 2010 and 2009 on- and off-peak prices, with 2010 prices being substantially higher than 2009.

The following table provides summary financial data regarding our Coal segment results of operations for the years ended December 31, 2010 and 2009, respectively:

	Year Ended December 31,			
	2010	2009	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$ 699	$ 670	$ 29	4%
Capacity	17	45	(28)	(62)%
Financial transactions:				
Mark-to-market income (loss)	21	(108)	129	119%
Financial settlements	97	373	(276)	(74)%
Option premiums	7	(38)	45	118%
Total financial transactions	125	227	(102)	(45)%
Other(1)	(5)	(2)	(3)	(150)%
Total revenues	836	940	(104)	(11)%
Cost of sales	(355)	(345)	(10)	(3)%
Gross margin	$ 481	$ 595	$ (114)	(19)%
Million Megawatt Hours Generated	22.3	20.7	1.6	8%
In Market Availability for Coal Fired Facilities(2)	91%	90%		
Average Quoted On-Peak Market Power Prices ($/MWh)(3):				
Cinergy (Cin Hub)	$ 42	$ 35	$ 7	20%

(1) Other includes ancillary services and other miscellaneous items.

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

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

Gross margin from the Coal segment decreased by $114 million from $595 million for the year ended December 31, 2009, to $481 million for the year ended December 31, 2010. This decrease was driven by the following:

- Settlements revenue decreased by $276 million due to less revenue generated from the financial settlement of derivative instruments.

Capacity revenue decreased by $28 million due to lower capacity prices in the MISO capacity market in 2010 compared to 2009.

Mark-to-market revenue increased by $129 million due to a net change in mark-to-market loss of $108 million in 2009 to mark-to-market revenue of $21 million in 2010.

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Premium revenue increased by $45 million due to fewer options purchased in 2010 compared to 2009. The volume of transactions executed that contained premiums was lower in the second half of 2010 as a result of changes in trading methodology in anticipation of the Blackstone transaction.

Energy revenue and the corresponding cost of sales increased by $29 million and $10 million, respectively, for a net increase in energy margin of $19 million. Energy revenue and cost of sales increased due to higher volumes generated and higher pricing. Generation volumes were up due to fewer planned outages at Havana and Wood River in 2010 compared to 2009.

Gas Segment. Although spark-spreads were up in most regions, year over year, gross margin was down mainly due to the expiration of the South Bay tolling agreement and the sale of Bridgeport to LS Power, both of which occured in 2009. Spark spreads were down year over year in California which also led to the reduction in gross margin.

The following table provides summary financial data regarding our Gas segment results of operations for the years ended December 31, 2010 and 2009, respectively:

	Year Ended December 31,			
	2010	**2009**	**Change**	**% Change**
	(dollars in millions)			
Revenues:				
Energy	$ 619	$ 633	$ (14)	(2)%
Capacity	231	248	(17)	(7)%
RMR	45	6	39	650%
Tolls	137	188	(51)	(27)%
Natural gas	169	128	41	32%
Financial transactions:				
Mark-to-market losses	(11)	(130)	119	92%
Financial settlements	(117)	(35)	(82)	(234)%
Option premiums	127	197	(70)	(36)%
Total financial transactions	(1)	32	(33)	(103)%
Other(1)	23	25	(2)	(8)%
Total revenues	1,223	1,260	(37)	(3)%
Cost of sales	(707)	(716)	9	1%
Gross margin	$ 516	$ 544	$ (28)	(5)%
Million Megawatt Hours Generated(2)	14.2	17.6	(3.4)	(19)%
Average Capacity Factor for Combined Cycle Facilities(3)	31%	36%		
Average Quoted On-Peak Market Power Prices ($/MWh)(4):				
Commonwealth Edison (NI Hub)	$ 41	$ 35	$ 6	17%
PJM West	$ 54	$ 45	$ 9	20%
North Path 15 (NP 15)	$ 40	$ 39	$ 1	3%
New York Zone A	$ 44	$ 36	$ 8	22%
Mass Hub	$ 56	$ 46	$ 10	22%
Average Market Spark Spreads ($/MWh)(5):				
PJM West	$ 19	$ 12	$ 7	58%
North Path 15 (NP 15)	$ 6	$ 8	$ (2)	(25)%
New York Zone A	$ 9	$ 4	$ 5	125%
Mass Hub	$ 18	$ 12	$ 6	50%
Average natural gas price Henry Hub ($/MMBtu)(6)	$ 4.38	$ 3.92	$ 0.46	12%

(1)

Other includes ancillary services and other miscellaneous items.

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(2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility.

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

(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 or an 11.0 MMBtu/MWh heat rate fuel oil-fired 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) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Gross margin for the Gas segment decreased by $28 million from $544 million for the year ended December 31, 2009, to $516 million for the year ended December 31, 2010. The decrease was driven by the following:

- Settlements revenue decreased by $82 million due to greater losses generated from the financial settlement of derivative instruments.

- Premium revenue decreased by $70 million due to fewer options sold in 2010 compared to 2009. The volume of transactions executed that contained premiums was lower in the second half of 2010 as a result of changes in trading methodology in anticipation of the Blackstone transaction.

- Tolling revenue decreased by $51 million primarily due to the expiration of the South Bay toll in December 2009.

- Capacity revenue decreased by $17 million primarily due to the sale of Bridgeport in the fourth quarter of 2009.

- Mark-to market revenue increased by $119 million due to a net change in mark-to-market loss of $130 million in 2009 to a mark-to-market loss of $11 million in 2010.

- Gas revenue increased by $41 million due to an increase in volumes sold in 2010 compared to 2009. The increase in volumes sold is due to lower 2010 power generation primarily at Moss Landing. The decrease in power generation made more gas available to be sold back to the market as it was not required for production.

- RMR revenue increased by $39 million due to the expiration of the South Bay toll in December 2009. With the toll ending, the need to pass through RMR revenue ended as well; therefore, South Bay was able to keep all RMR proceeds.

DNE Segment. Average dark spreads at Danskammer increased slightly year over year. Average power prices in Zone G were up in 2010 compared to 2009.

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The following table provides summary financial data regarding our DNE segment results of operations for the years ended December 31, 2010 and 2009, respectively:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Change	% Change
	(dollars in millions)			
Revenues:				
Energy	$ 142	$ 131	$ 11	8%
Capacity	41	45	(4)	(9)%
Financial transactions:				
Mark-to-market income	18	31	(13)	(42)%
Financial settlements	32	60	(28)	(47)%
Option premiums	7	(8)	15	188%
Total financial transactions	57	83	(26)	(31)%
Other(1)	24	14	10	71%
Total revenues	264	273	(9)	(3)%
Cost of sales	(121)	(134)	13	10%
Gross margin	$ 143	$ 139	$ 4	3%
Million Megawatt Hours Generated	2.2	2.5	(0.3)	(12)%
In Market Availability for Coal Fired Facilities(2)	95%	95%		
Average Capacity Factor Coal	53%	63%		
Average Capacity Factor Gas	4%	4%		
Average Quoted On-Peak Market Power Prices ($/MWh)(3):				
New York Zone G	$ 59	$ 50	$ 9	18%
Average Market Spark Spreads ($/MWh)(4):				
Fuel Oil	$ (72)	$ (53)	$ (19)	(36)%

(1) Other includes ancillary services and other miscellaneous items.

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

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

(4) Reflects the simple average of the spark spread available to a 7.0 MMBtu/MWh heat rate generator or an 11.0 MMBtu/MWh heat rate fuel oil-fired 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.

Gross margin for the DNE segment increased by $4 million from $139 million for the year ended December 31, 2009, to $143 million for the year ended December 31, 2010. The increase was driven by the following:

- Energy revenue increased by $11 million and the corresponding cost of sales decreased by $13 million for a net increase in energy margin of $24 million. Energy revenue increased due to higher pricing. Cost of sales decreased due to lower generation and an $11 million lower of cost or market adjustment made in 2009 that was not repeated in 2010.

Premium revenue increased by $15 million due to an increase in the number of options sold during the first half of 2010.

Other revenue increased by $10 million primarily due to the 2010 sale of Roseton fuel oil.

Settlements revenue decreased by $28 million due to less revenue generated from the financial settlement of derivative instruments.

Mark-to-market revenue decreased by $13 million due to a net change in mark-to-market revenue of $31 million in 2009 to mark-to-market revenue of $18 million in 2010.

Outlook

We have implemented a modification of our asset ownership structure which eliminated our former regional organizational structure. We are focused on reducing and consolidating non-plant support activities and achieving cost efficiencies at both operating facilities and corporate support functions. Going forward, we have an operating fleet supported by our service contracts, which has resulted in adjusting corporate functions to support the new operational model.

On November 7, 2011, the Debtor Entities filed the Chapter 11 Cases. Neither Dynegy nor any of its direct or indirect subsidiaries other than the five Debtor Entities sought protection from creditors, and none of those entities are debtors under Chapter 11 of the Bankruptcy Code. The Debtor Entities are continuing to operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. Coal HoldCo and its indirect, wholly-owned subsidiary, DMG, as well as all other subsidiaries of DH other than the Debtor Entities, including DPC and all of its subsidiaries, are not included in the Chapter 11 Cases. The normal day-to-day operations of the coal-fired power generation facilities held by DMG and the natural gas-fired generation facilities held by DPC are continuing without interruption.

We expect that our future financial results will continue to be sensitive to fuel and commodity prices, especially gas prices, and the impact on such prices of shale gas production. Other factors to which our future financial results will remain sensitive include 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, the volatility of fuel and electricity prices, transportation and transmission logistics, weather conditions and IMA. Further, 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.

Coal. The Coal segment consists of six plants, all located in the MISO region, and totaling 3,132 MW.

Our Consent Decree requires substantial emission reductions from our Illinois coal-fired power plants and the completion of several supplemental environmental projects in Illinois. We have achieved all emission reductions scheduled to date under the Consent Decree and only Baldwin Unit 2 has material outstanding Consent Decree work yet to be performed, which is scheduled for completion by the end of 2012. We expect our costs associated with the remaining Consent Decree projects to be approximately $71 million and $5 million in 2012 and 2013, respectively. This estimate includes a number of assumptions about uncertainties beyond our control, such as costs associated with labor and materials.

Our expected coal requirements are 100 percent contracted and priced in 2012. Our forecast coal requirements for 2013 are 62 percent committed. Those volumes are unpriced but are subject to a price collar structure. Our coal transportation requirements are 100 percent contracted and priced through 2013. Coal transportation rates will be renewed in 2014 at levels higher than our current rates. 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 Coal expected generation volumes are volumetrically 61 percent hedged through 2012 and approximately 6 percent hedged for 2013.

Recent moves by various market transmission-owning entities expressing their intentions to either join or exit the MISO could impact system planning reserve margins in the future. The MISO filed proposed Resource Adequacy Enhancements with FERC on July 20, 2011. The proposed tariff revisions require capacity to be procured on a zonal basis for a full planning year (June 1 - May 31) versus the current monthly requirement, with procurement occurring two months ahead of the planning year. If approved, the new construct would be in place for the 2013-14 Planning Year. While the proposed new construct is an incremental improvement over the status quo, it is unlikely to have an influence on capacity prices in the near future due to excess capacity in the MISO market. In addition, 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 market prices in the future.

Gas. The Gas segment consists of eight plants, geographically diverse in five markets, totaling 6,771 MW. Approximately 70 percent of our power plant capacity in the CAISO market is contracted through 2012 under tolling agreements with load-serving entities and an RMR agreement. A significant portion of the remaining capacity is sold as a resource adequacy product in the CAISO market, and much of our remaining expected production in the CAISO market has been financially hedged.

The CAISO capacity market is bilateral in nature. The load-serving entities are required to procure sufficient resources for their peak load plus a fifteen percent reserve margin. The CAISO footprint currently has a capacity surplus due to a weak economy and increased participation from renewable resources. The CAISO faces challenges to ensure system reliability as well as adequate ancillary services in the future with the mandate to have 33% renewable resources by 2020. The combination of bilateral markets, one-off utility procurements, and short-term requirements make this a larger concern than in other markets where multi-year forward requirements and more transparent markets are in place. The recent request to retire a modern combined cycle facility resulted in a recently announced stakeholder process on long-term resource adequacy which we hope will lead to a collaborated effort to a market-based solution that meets the needs of all stakeholders.

South Bay's RMR designation was terminated at the end of 2010, and as a result, the South Bay power generation facility was permanently retired and is currently in the process of being decommissioned. We have a contractual obligation to demolish the facility and potentially remediate specific parcels of the property. Our cost estimates for the demolition of the facility have not been finalized, but our obligation is expected to be approximately $37 million, exclusive of certain rental payments that will be due the Port of San Diego.

The estimated useful lives of our generation facilities consider environmental regulations currently in place. With respect to Units 6 and 7 at our Moss Landing facility, we are continuing to review the potential impact of the California Water Intake Policy. We are currently depreciating these units through 2024; however, depending on the ultimate impact of the California Water Intake Policy, we may determine that we would be required to install cooling systems that could render operation of the units uneconomical. If such a determination were to be made, we could decide to reduce operations or cease to operate the units as early as December 31, 2017. A decision to cease operations at the end of 2017 would result in the acceleration of depreciation on the remaining net book values of the units, which totaled $332 million at December 31, 2011.

In New England, five forward capacity auctions have been held since the ISO-NE transitioned to a forward capacity market in June 2010. Capacity clearing prices have ranged from a high of $4.50 per kW-month for the 2010-2011 market period to a low of $2.95 per kW-month for the 2013-2014 market period. During the most recent forward capacity market auction for the 2014-2015 market period, held in June of 2011, capacity cleared at $3.21 per kW-month. These capacity clearing prices represent the

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floor price, although the actual rate paid to Casco Bay (and other facilities) can be reduced due to oversupply conditions and/or regional export limits. 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.

In PJM, where the Kendall and Ontelaunee combined-cycle plants are located, eight forward capacity auctions (known as RPM or Reliability Pricing Model) have been held since the transition from a daily capacity market in June 2007. RPM clearing prices have ranged from $0.50/kW-month (Kendall, PY2012-13) and $1.24/kW-month (Ontelaunee, PY2007-8) to $5.30/kW-month (Kendall, PY2010-11) and $6.88/kW-month (Ontelaunee, PY2013-14). The latest RPM auction was for the 2014-2015 Planning Year, which cleared at $3.83/kW-month (Kendall) and $4.15/kW-month (Ontelaunee).

In New York, capacity prices continue to trend downward due to surplus capacity and lower demand, although approximately 73 percent of the capacity revenue for our Independence facility has been contracted at a favorable premium compared to current market prices through 2014.

Currently, our Gas portfolio is approximately 92 percent hedged volumetrically through 2012 and approximately 16 percent hedged for 2013.

We plan to continue our hedging program for Gas over a rolling 12-36 month period using various forward sale instruments. Beyond 2013, the portfolio is largely open, positioning Gas to benefit from possible future power market pricing improvements.

DNE. DNE is comprised of the Roseton and Danskammer facilities located in Newburgh, New York, with a total capacity of 1,693 MW. A total of 1,570 MW of generation capacity relate to leased units at the two facilities. In connection with the Chapter 11 cases, the Debtor Entities rejected these long-term leases. The Debtor Entities have remained in physical possession of and have continued to operate the leased facilities to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facilities is permitted to be transitioned. Please read Note 3 Chapter 11 Cases for further discussion.

A substantial portion of expected physical coal supply and delivery requirements for 2012 is fully contracted and priced for the forecasted run throughout the remainder of the year. Shortfall due to unexpectedly high burn rate will be purchased in the spot market from domestic suppliers.

We have not hedged any of our generation volumes for 2012.

Other. Other includes traditional corporate support functions, including those services contemplated in the various service agreements, including the Service Agreements, Energy Management Agreements, a Tax Sharing Agreement and Cash Management Agreements, which were entered into in conjunction with the Reorganization.

During 2011, we initiated a new cost and performance improvement initiative, known as PRIDE ("Producing Results through Innovation by Dynegy Employees"), which is designed to drive recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency. In 2011 alone, we recognized $64 million in operating margin and cost improvements versus 2010 and $376 million in incremental liquidity from balance sheet improvements due to PRIDE initiatives. In 2012, we are targeting additional margin and cost improvements of $40 million, and additional balance sheet improvements of $100 million. We will continue to use the PRIDE initiative to improve our operating performance, cost structure and balance sheet.

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SEASONALITY

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

CRITICAL ACCOUNTING POLICIES

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

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

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

Revenue Recognition and Valuation of Risk Management Assets and Liabilities

We earn revenue from our facilities in three primary ways: (i) the sale of both fuel and energy through both physical and financial transactions to optimize the financial performance of our generating facilities; (ii) sale of capacity; and (iii) sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative. Please read "Derivative Instruments Generation" for further discussion of the accounting for these types of transactions.

Derivative Instruments Generation. We enter into commodity contracts that meet the definition of a derivative. These contracts are often entered into to mitigate or eliminate market and financial risks associated with our generation business. These contracts include power sales contracts, fuel purchase contracts, options, swaps, and other instruments used to mitigate variability in earnings due to fluctuations in market prices. There are three different ways to account for these types of contracts: (i) as an accrual contract, if the criteria for the "normal purchase normal sale" exception are met and documented; (ii) as a cash flow or fair value hedge, if the criteria are met and documented; or

(iii) as a mark-to-market contract with changes in fair value recognized in current period earnings. All

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derivative commodity contracts that do not qualify for the "normal purchase normal sale" exception are recorded at fair value in risk management assets and liabilities on the consolidated balance sheets. If the derivative commodity contract has been designated as a cash flow hedge, the changes in fair value are recognized in earnings concurrent with the hedged item. Changes in the fair value of derivative commodity contracts that are not designated as cash flow hedges are recorded currently in earnings. Because derivative contracts can be accounted for in three different ways, and as the "normal purchase normal sale" exception and cash flow and fair value hedge accounting are elective, the accounting treatment used by another party for a similar transaction could be different from the accounting treatment we use. To the extent a party elects to apply cash flow hedge accounting for qualifying transactions, there is generally less volatility in the statements of operations as the effective portion of the changes in the fair values of the derivative instruments is recognized through equity. We do not utilize hedge accounting for our commodity contracts.

Entities may choose whether or not to offset related assets and liabilities and report the net amounts on their consolidated balance sheet if the right of setoff exists. We execute a significant volume of transactions through futures clearing managers. Our daily cash payments (receipts) to (from) our futures clearing managers 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 of options ("Options," and collectively with Daily Cash Settlements and Initial Margin, "Collateral"). We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement and we elect not to offset the fair value of amounts recognized for the Daily Cash Settlements paid or received against the fair value of amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. As a result, our consolidated balance sheets present derivative assets and liabilities, as well as the related cash collateral paid or received, on a gross basis.

Derivative Instruments Financing Activities. We are exposed to changes in interest rate risk through our variable and fixed rate debt. In order to manage our interest rate risk, we enter into interest rate swap agreements that meet the definition of a derivative. All derivative instruments are recorded at their fair value on the consolidated balance sheet. If the derivative is designated as a cash flow hedge, the effective portions of the changes in the fair value of the derivative are recorded in OCI and the realized gains and losses related to these derivatives are recognized in earnings in the same period as the settlement of the underlying hedged transaction. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized currently in earnings. If the derivative is not designated as a hedge, the change in value is recognized currently in earnings. To the extent a party elects to apply hedge accounting for qualifying transactions, there is generally less volatility in the statements of operations as a portion of the changes in the fair value of the derivative instruments is recognized through equity.

Fair Value Measurements. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of our assets and liabilities measured and reported at fair value. Where appropriate, valuation adjustments are made to account for various factors, including the impact of our credit risk, our counterparties' credit risk and bid-ask spreads. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observability of those

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inputs. The inputs used to measure fair value have been placed in a hierarchy based on priority. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

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

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

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to our needs. At each balance sheet date, we perform an analysis of all instruments and include in Level 3 all of those whose fair value is based on significant unobservable inputs.

The determination of the fair values incorporates various factors. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities. Valuation adjustments are generally based on capital market implied ratings evidence when assessing the credit standing of our counterparties and when applicable, adjusted based on management's estimates of assumptions market participants would use in determining fair value.

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

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Estimated Useful Lives

The estimated useful lives of our long-lived assets are used to compute depreciation expense and 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 of carrying values of tangible and intangible assets may result.

The estimated useful lives of our generation facilities consider environmental regulations currently in place. Environmental regulations could be introduced or enacted at any time, requiring us to adjust the estimated useful lives of our other generation facilities, and potentially resulting in a significant acceleration of depreciation expense.

Valuation of Tangible and Intangible Assets and Unconsolidated Investments

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

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

We assess the carrying value of our property, plant and equipment and intangible assets subject to amortization. If an impairment is indicated, the amount of the impairment loss recognized is determined by the amount the carrying value exceeds the estimated fair value of the assets. For assets identified as held for sale, the carrying value is compared to the estimated sales price less costs to sell. Please read Note 8 Impairment and Restructuring Charges for discussion of impairment charges we recognized in 2011, 2010 and 2009.

We review our equity investments by comparing the book value of the investment to the estimated fair value to determine if an impairment is required. We record a loss when the decline in value is considered other than temporary. Please read Note 16 Variable Interest Entities for further discussion. Additionally, upon deconsolidation of DH on November 7, 2011, we were required to record our investment in DH at its estimated fair value. Please read Note 3 Chapter 11 Cases Accounting Impact for further discussion.

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

We previously assessed the carrying value of our goodwill annually on November 1 or when circumstances warrant. Step 1 of the goodwill impairment test compares the fair value of a reporting unit to its carrying amount. Step 2 of the goodwill impairment test compares the implied fair value of

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each reporting unit's goodwill with the carrying amount of such goodwill through a hypothetical purchase price allocation of the fair value of the reporting unit to the reporting unit's tangible and intangible assets. As of March 31, 2009, our goodwill was fully impaired. Please read Note 17 Goodwill for further discussion of our impairment analysis.

Accounting for Contingencies, Guarantees and Indemnifications

We are involved in numerous lawsuits, claims, proceedings, and tax-related audits in the normal course of our operations. We record a loss contingency reserve for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingency reserves on an ongoing basis to ensure that we have appropriate reserves recorded on our consolidated balance sheets. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant. Our estimates and judgments could change based on new information, changes in laws or regulations, changes in management's plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from these reserves.

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

We disclose and account for various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification is entered into, an estimated fair value of the underlying guarantee or indemnification is recorded. Some guarantees and indemnifications could have significant financial impact under certain circumstances and management also considers the probability of such circumstances occurring when estimating the fair value. Actual results may materially differ from the estimated fair value of such guarantees and indemnifications.

Please read Note 23 Commitments and Contingencies for further discussion of our commitments and contingencies.

Accounting for Variable Interest Entities

We evaluate certain entities to determine if a party is considered the primary beneficiary of the entity and thus required to consolidate it in its financial statements. As a result of the Chapter 11 Cases and given the role of the Bankruptcy Court subsequent to the bankruptcy filing, we evaluated our investment in DH to determine if Dynegy Inc. continued to have a controlling financial interest in DH subsequent to the bankruptcy filing.

DH is a variable interest entity ("VIE"), and there is a significant amount of judgment involved in the analysis used to determine the primary beneficiary. The analysis includes determining the activities that most significantly impact the performance of the VIE, who has the power to direct those activities and who has the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE.

Under this model, we concluded that we were not the primary beneficiary of DH because, subsequent to the bankruptcy filing, we do not have the ability to make decisions that most significantly impact the economic performance of DH given the powers of the Bankruptcy Court. Therefore, under

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applicable accounting standards, we are no longer deemed to have a controlling financial interest in DH as of November 7, 2011. As a result, we deconsolidated our investment in DH on November 7, 2011 and commenced accounting for DH as an equity method investment. Please read Note 3 Chapter 11 Cases and Note 16 Variable Interest Entities for further discussion.

Prior to 2011, we were an investor, with independent third parties, in PPEA Holding. PPEA Holding is a variable interest entity. We concluded that we were not the primary beneficiary of PPEA Holding because the power to direct the activities that most significantly impact PPEA Holding's economic performance was shared by the members of PPEA Holding and the participants in the Plum Point Project. We determined the activities that most significantly impact PPEA Holding's economic performance were changes to the costs to complete the facility, modifications to the off-take agreements, and/or changes in the financing structure. As a result, we deconsolidated our investment in PPEA Holding which was accounted for as an equity method investment until we sold our interest in the investment on November 10, 2010. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion.

Prior to the adoption of ASU No. 2009-17 on January 1, 2010, the analysis included assumptions about forecasted cash flows, construction costs, and plant performance. Under the previous accounting model, we had concluded that we were the primary beneficiary of PPEA Holding and therefore consolidated the entity in our consolidated financial statements.

If different judgment had been applied, a different conclusion about the primary beneficiary of this entity could have resulted, which would have significantly impacted our financial condition, results of operations and cash flows.

Please read Note 16 Variable Interest Entities for further discussion of our accounting for our variable interest entities.

Accounting for Income Taxes

We use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

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

Because we operate and sell power in many different states, our effective annual state income tax rate will vary from period to period because of changes in our sales profile by state, as well as jurisdictional and legislative changes by state. As a result, changes in our estimated effective annual state income tax rate can have a significant impact on our measurement of temporary differences. We project the rates at which state tax temporary differences will reverse based upon estimates of revenues and operations in the respective jurisdictions in which we conduct business. A change of 1 percent in the estimated effective annual state income tax rate at December 31, 2011 could impact deferred tax expense by approximately $22 million.

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

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preceding years, as well as all currently available information about future years, anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

Upon deconsolidation of DH, we recorded a deferred tax asset for the difference between the carrying value of our investment in DH of zero and our outside tax basis in the stock of DH of $3,910 million. After assessing the positive and negative evidence relating the utilization of our deferred tax assets, management believes that it is more likely that not that we will not be able to realize the tax benefits from any net deferred tax assets not otherwise realized by reversing temporary differences and, therefore, a valuation allowance of $1,235 million was recorded at December 31, 2011.

Accounting for uncertainty in income taxes requires that we determine whether it is more likely than not that a tax position we have taken will be sustained upon examination. If we determine that it is more likely than not that the position will be sustained, we recognize the largest amount of the benefit that is greater than 50 percent likely of being realized upon settlement. There is a significant amount of judgment involved in assessing the likelihood that a tax position will be sustained upon examination and in determining the amount of the benefit that will ultimately be realized. If different judgments were applied, it is likely that reserves would be recorded for different amounts. Actual amounts could vary materially from these reserves.

Please read Note 21 Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions and change in our valuation allowance.

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

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

We used a yield curve approach for determining the discount rate as of December 31, 2011. The discount rate is subject to change each year, consistent with changes in applicable high-quality, long-term corporate bond indices. Projected benefit payments for the plans were matched against the discount rates in the yield curve to produce a weighted-average equivalent discount rate. Long-term interest rates decreased during 2011. Accordingly, at December 31, 2011, we used a discount rate of 4.80 percent for pension plans and 4.93 percent for other retirement plans, a decrease of 69 and 68 basis points, respectively, from the 5.49 percent rate for pension plans and the 5.61 percent rate for other retirement plans used as of December 31, 2010. This decrease in the discount rate increased the underfunded status of the plans by $28 million.

The expected long-term rate of return on pension plan assets is selected by taking into account the asset mix of the plans and the expected returns for each asset category. Based on these factors, our expected long-term rate of return as of January 1, 2011 and 2010 was 7.00 percent and 8.00 percent, respectively.

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

	Impact on PBO, December 31, 2011	Impact on 2012 Expense
	(in millions)	
Increase in Discount Rate 50 basis points	$ (18)	$ (2)
Decrease in Discount Rate 50 basis points	20	2
Increase in Expected Long-term Rate of Return 50 basis points		(1)
Decrease in Expected Long-term Rate of Return 50 basis points		1

We expect to make $20 million in cash contributions related to our pension plans during 2012. In addition, we will likely be required to continue to make contributions to the pension plans beyond 2012. Although it is difficult to estimate these potential future cash requirements due to uncertain market conditions, we currently expect that we will contribute approximately $16 million in 2013 and $18 million in 2014.

Please read Note 25 Employee Compensation, Savings and Pension Plans for further discussion of our pension-related assets and liabilities.

RECENT ACCOUNTING PRONOUNCEMENTS

Please read Note 2 Summary of Significant Accounting Policies for further discussion of accounting policies not yet adopted.

RISK-MANAGEMENT DISCLOSURES

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

	As of and for the Year Ended December 31, 2011
	(in millions)
Balance Sheet Risk-Management Accounts(1)	
Fair value of portfolio at January 1, 2011	$ 34
Risk-management gains (losses) recognized through the statements of operations in the period, net	(107)
Cash paid (received) related to risk-management contracts settled in the period, net	(57)
Deconsolidation of DH(2)	131
Non-cash adjustments and other	4
Fair value of portfolio at December 31, 2011	$ 5

(1) Our modeling methodology has been consistently applied.

(2) As a result of the Chapter 11 Cases, DH was deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

The net risk-management asset of $5 million is the aggregate of the following line items on the consolidated balance sheets: Current Assets Assets from risk-management activities and Assets from risk-management activities, affiliate, Other Assets Assets from risk-management activities and Assets from risk-management activities, affiliate, Current Liabilities Liabilities from risk-management activities and Liabilities from risk-management activities, affiliate and Other Liabilities Liabilities from risk-management activities and Liabilities from risk-management activities, affiliate .

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Net Fair Value of Risk-Management Portfolio

	Total	2012	2013	2014	2015	2016	Thereafter
				(in millions)			
Market Quotations(1)(2)	$	$ 2	$ 1	$	$	$ (3)	$
Value Based on Models Affiliates(2)	5	1	4				
Total	$ 5	$ 3	$ 5	$	$	$ (3)	$

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

(2) The market quotations and prices based on models categorization differs from the categories of Level 1, Level 2 and Level 3 used in our fair value disclosures due to the application of the different methodologies. Please read Note 9 Risk Management Activities, Derivatives and Financial Instruments and Note 10 Fair Value Measurements for further discussion.

Derivative Contracts

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

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

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

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

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

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

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

VaR. The modeling of the risk characteristics of our mark-to-market portfolio involves a number of assumptions and approximations. We estimate VaR using a Monte Carlo simulation-based methodology. Inputs for the VaR calculation are prices, positions, instrument valuations and the variance-covariance matrix. VaR does not account for liquidity risk or the potential that adverse market conditions may prevent liquidation of existing market positions in a timely fashion. While management believes that these assumptions and approximations are reasonable, there is no uniform industry

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methodology for estimating VaR, and different assumptions and/or approximations could produce materially different VaR estimates.

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

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

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

The following table sets forth the aggregate daily VaR and average VaR of the mark-to-market portion of our risk-management portfolio primarily associated with the Coal, Gas and DNE segments. The VaR calculation does not include market risks associated with the accrual portion of the risk-management portfolio that is designated as a cash flow hedge or a "normal purchase normal sale," nor does it include expected future production from our generating assets.

The decrease in the December 31, 2011 one day VaR was primarily due to decreased forward commodity transactions, lower commodity prices, and lower historical volatilities levels as compared to December 31, 2010.

Daily and Average VaR for Mark-to-Market Portfolios

	December 31, 2011	December 31, 2010
	(in millions)	
One day VaR 95 percent confidence level	$ 12	$ 14
One day VaR 99 percent confidence level	$ 18	$ 20
Average VaR for the year-to-date period 95 percent confidence level	$ 9	$ 22

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

Our Credit Department, based on guidelines approved by the Board of Directors, establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical

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delivery and financial contracts. Our credit risk system provides current credit exposure to counterparties on a daily basis.

The following tables represents our credit exposure at December 31, 2011 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary Dynegy Inc.

	Investment Grade Quality	Non-Investment Grade Quality	Total
		(in millions)	
Type of Business:			
Financial institutions	$ 2	$	$ 2
Other	4		4
Total	$ 6	$	$ 6

Credit Exposure Summary DH

	Investment Grade Quality	Non-Investment Grade Quality	Total
		(in millions)	
Type of Business:			
Financial institutions	$ 2	$	$ 2
Utility and power generators	28		28
Total	$ 30	$	$ 30

Interest Rate Risk Dynegy Inc.

We are exposed to fluctuating interest rates related to variable rate financial obligations. As of December 31, 2011, all of our third party debt is considered variable rate debt. We use a variety of instruments, including interest rate swaps and caps, to mitigate this interest rate exposure. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of December 31, 2011, to the extent LIBOR remains below 1.5 percent, which represents the interest rate floor in the DMG credit agreement, LIBOR changes will have no impact to interest expense in 2012. We estimate that increases in LIBOR to ranges between 1.5 and 2 will result in up to $3 million in increased interest expense in 2012. It is estimated that a one percentage point interest rate movement in the average market interest rates would change interest expense by up to approximately $1 million to the extent LIBOR exceeds 2 percent, which represents the interest rate when certain hedging instruments become effective. This exposure would have been partially offset by an approximate $2 million increase or decrease in interest income related to the restricted cash balance of $152 million posted as collateral to support our letter of credit facilities regardless of interest rate. Over time, we may seek to adjust the variable rate exposure in our debt portfolio through the use of additional swaps or other financial instruments.

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The absolute notional financial contract amounts associated with our interest rate contracts were as follows at December 31, 2011 and December 31, 2010, respectively:

	December 31, 2011	December 31, 2010
Fair value hedge interest rate swaps (in millions of U.S. dollars)	$	$ 25
Fixed interest rate received on swaps (percent)		5.70
Interest rate risk-management contracts (in millions of U.S. dollars)	$ 312	$ 231
Fixed interest rate paid (percent)	2.22	5.35
Interest rate risk-management contracts (in millions of U.S. dollars)	$	$ 206
Fixed interest rate received (percent)		5.28
Interest rate risk-management contracts (in millions of U.S. dollars)(1)	$ 500	$
Interest rate threshold (percent)	2.00	

(1) The 2011 interest rate contracts limit our exposure to changes in interest rates to the extent LIBOR exceeds 2 percent.

Item 8. *Financial Statements and Supplementary Data*

Our consolidated financial statements and financial statement schedules are set forth at pages F-1 through F-100 inclusive, found at the end of this annual report, and are incorporated herein by reference.

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

Not applicable.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2011.

Management's Report on Internal Control over Financial Reporting

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

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

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and

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expenditures of our company are being made only in accordance with authorizations of our management and directors; and

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, we used the criteria set forth in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this assessment and on those criteria, we concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

Changes in Internal Controls Over Financial Reporting

Effective November 7, 2011, DH and its direct and indirect subsidiaries were deconsolidated from Dynegy. Financial statements presented after November 7, 2011 reflect our investment in, and the results of operations of, DH and its wholly owned subsidiaries under the equity method of accounting. For further discussion, please read Note 3 Chapter 11 Cases Accounting Impact.

As a result of this change in accounting, we made changes that materially affected our internal controls over financial reporting during the quarter ended December 31, 2011. Specifically, we developed and implemented changes to our processes and controls designed to account for and report on our deconsolidation of DH and resulting investment in DH using the equity method of accounting. These included but were not necessarily limited to, processes and controls for calculating the valuation of our investment in DH, recording and reporting our share of income (loss), intercompany transactions and the resulting account balances, and preparing the related financial statement classifications and disclosures. Controls implemented included: (i) new processes around the consolidation of Dynegy to consider the deconsolidation of DH, including detailed reconciliations of the impact of the deconsolidation on the balance sheet, statement of operations and statement of cash flow; (ii) additional procedures around the identification, analysis and recording of the activities of DH, and the resulting impact of these activities on Dynegy, including related party disclosures; and (iii) related reviews by management.

There were no other changes in our internal controls over financial reporting that materially affected or are reasonably likely to materially affect our internal controls over financial reporting during the quarter ended December 31, 2011.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.

We have audited Dynegy Inc.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Dynegy Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Dynegy Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2011 consolidated financial statements of Dynegy Inc. and our report dated March 8, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 8, 2012

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

Not applicable.

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PART III

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

Executive Officers. We intend to include the information with respect to our executive officers required by this Item 10 in our definitive proxy statement for our 2012 annual meeting of stockholders under the heading "Executive Officers;" which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2011. However, if such proxy statement is not filed within such 120-day period, information with respect to Executive Officers will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

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

Other Information. We intend to include the other information required by this Item 10 in our definitive proxy statement for our 2012 annual meeting of stockholders under the headings "Proposal 1 Election of Directors" and "Compliance with Section 16(a) of the Exchange Act," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2011. However, if such proxy statement is not filed within such 120-day period, information with respect to Other Information will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 11. *Executive Compensation*

We intend to include information with respect to executive compensation in our definitive proxy statement for our 2012 annual meeting of stockholders under the heading "Executive Compensation," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2011. However, if such proxy statement is not filed within such 120-day period, information with respect to executive compensation will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

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

We intend to include information regarding ownership of our outstanding securities and securities authorized for issuance under equity compensation plans in our definitive proxy statement for our 2012 annual meeting of stockholders under the heading "Security Ownership of Certain Beneficial Owners and Management" and "Securities Authorized for Issuance Under Equity Compensation Plan," respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2011. However, if such proxy statement is not filed within such 120-day period, information with respect to beneficial ownership will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

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

We intend to include the information regarding related party transactions and Director independence in our definitive proxy statement for our 2012 annual meeting of stockholders under the headings "Transactions with Related Persons, Promoters and Certain Control Persons," and "Corporate Governance," respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2011. However, if such proxy statement is not filed within such 120-day period, information with respect to certain relationships will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 14. ***Principal Accountant Fees and Services***

We intend to include information regarding principal accountant fees and services in our definitive proxy statement for our 2012 annual meeting of stockholders under the heading "Independent Registered Public Auditors Principal Accountant Fees and Services," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2011. However, if such proxy statement is not filed within such 120-day period, information with respect to the principal accountant fees and services will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 15. ***Exhibits and Financial Statement Schedules***

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

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

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

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

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of August 13, 2010, among Dynegy Inc., Denali Parent Inc. and Denali Merger Sub Inc. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on August 13, 2010, File No. 000-29311).
2.2	Amendment No. 1 to the Agreement and Plan of Merger, dated as of November 16, 2010, among Dynegy Inc., Denali Parent Inc. and Denali Merger Sub Inc. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on November 17, 2010, File No. 000-29311).
2.3	Membership Interest Purchase Agreement by and between Dynegy Gas Investments, LLC and Dynegy Inc. dated September 1, 2011 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Holdings, LLC filed on September 8, 2011, File No. 000-29311).
2.4	Undertaking Agreement by and between Dynegy Gas Investments, LLC and Dynegy Inc. dated September 1, 2011 (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K of Dynegy Holdings, LLC filed on September 8, 2011, File No. 000-29311).
2.5	Amended and Restated Undertaking Agreement by and between Dynegy Holdings, LLC and Dynegy Inc. (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K of Dynegy Holdings, LLC filed on September 8, 2011, File No. 000-29311).

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Exhibit Number	Description
2.6	Agreement and Plan of Merger, dated as of December 15, 2010 among Dynegy Inc., IEH Merger Sub LLC, and IEP Merger Sub Corp. (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 15, 2010, File No. 001-33443).
2.7	Amendment No. 1 to the Agreement and Plan of Merger, dated as of February 13, 2011 among Dynegy Inc., IEH Merger Sub LLC, and IEP Merger Sub Corp. (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 14, 2011, File No. 001-33443).
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).
3.2	Dynegy Inc. Third Amended and Restated Bylaws, as amended on November 17, 2011 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on November 17, 2011, File No. 001-33443).
4.1	Subordinated Debenture Indenture between NGC Corporation and The First National Bank of Chicago, as Debenture Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
***4.2	Amended and Restated Declaration of Trust among NGC Corporation, Wilmington Trust Company, as Property Trustee and Delaware Trustee, and the Administrative Trustees named therein, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
**4.3	Purchase Agreement, dated as of May 22. 1997, by and between NGC Corporation, NGC Corporation Capital Trust I and Lehman Brothers Inc., Salomon Brothers Inc. and Smith Barney Inc. as Exhibit C to the Amended and Restated Declaration of Trust among NGC Corporation, Wilmington Trust Company, as Property Trustee and Delaware Trustee, and the Administrative Trustees named therein, dated as of May 28, 1997.
4.4	Series A Capital Securities Guarantee Agreement executed by NGC Corporation and The First National Bank of Chicago, as Guarantee Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.5	Common Securities Guarantee Agreement of NGC Corporation, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).
4.6	Registration Rights Agreement, dated as of May 28, 1997, among NGC Corporation, NGC Corporation Capital Trust I, Lehman Brothers, Salomon Brothers Inc. and Smith Barney Inc. (incorporated by reference to Exhibit 4.11 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).

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Exhibit Number	Description
4.7	Indenture, dated as of September 26, 1996, restated as of March 23, 1998, and amended and restated as of March 14, 2001, between Dynegy Holdings Inc. and Bank One Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2000 of Dynegy Holdings Inc., File No. 000-29311).
4.8	First Supplemental Indenture, dated July 25, 2003 to that certain Indenture, dated as of September 26, 1996, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659).
4.9	Second Supplemental Indenture, dated as of April 12, 2006, to that certain Indenture, originally dated as of September 26, 1996, as amended and restated as of March 23, 1998 and again as of March 14, 2001, by and between Dynegy Holdings Inc. and Wilmington Trust Company (as successor to JPMorgan Chase Bank, N.A.), as trustee, as supplemented by that certain First Supplemental Indenture, dated as of July 25, 2003 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 12, 2006, File No. 1-15659).
4.10	Third Supplemental Indenture, dated as of May 24, 2007, to that certain Indenture, originally dated as of September 26, 1996, as amended and restated as of March 23, 1998 and again as of March 14, 2001, by and between Dynegy Holdings Inc. and Wilmington Trust Company (as successor to JPMorgan Chase Bank, N.A.), as trustee, as supplemented by that certain First Supplemental Indenture, dated as of July 25, 2003, and that certain Second Supplemental Indenture, dated as of April 12, 2006 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on May 25, 2007, File No. 000-29311).
4.11	Fourth Supplemental Indenture, dated as of May 24, 2007, to that certain Indenture, originally dated as of September 26, 1996, as amended and restated as of March 23, 1998 and again as of March 14, 2001, by and between Dynegy Holdings Inc. and Wilmington Trust Company (as successor to JPMorgan Chase Bank, N.A.), as trustee, as supplemented by that certain First Supplemental Indenture, dated as of July 25, 2003, that certain Second Supplemental Indenture, dated as of April 12, 2006, and that certain Third Supplemental Indenture, dated as of May 24, 2007 (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on May 25, 2007, File No. 000-29311).
4.12	Fifth Supplemental Indenture dated as of December 1, 2009 between Dynegy Holdings Inc. and Wilmington Trust Company (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on December 1, 2009, File No. 001-33443 and 000-29311, respectively).
4.13	7.5 percent Senior Unsecured Note Due 2015 (included in Exhibit 4.1 and incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on December 1, 2009, File No. 001-33443 and 000-29311, respectively).
4.14	Sixth Supplemental Indenture dated as of December 30, 2009 between Dynegy Holdings and Wilmington Trust Company (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings Inc. filed on January 4, 2010, File No. 001-33443 and 000-29311, respectively).

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Exhibit Number	Description
4.15	Registration Rights Agreement, effective as of July 21, 2006, by and among Dynegy Holdings Inc. RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 2006, File No. 1-15659).
4.16	Registration Rights Agreement, dated as of May 24, 2007, by and among Dynegy Holdings Inc. and the several initial purchasers party thereto (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on May 25, 2007, File No. 000-29311).
4.17	Shareholder Agreement, dated as of August 9, 2009 between Dynegy Inc. and LS Power and its affiliates (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on August 13, 2009, File No. 001-33443).
4.18	Registration Rights Agreement, dated as of September 14, 2006, among Dynegy Acquisition, Inc., LS Power Partners, L.P., LS Power Associates, L.P., LS Power Equity Partners, L.P., LS Power Equity Partners PIE I, L.P. and LSP Gen Investors, L.P. (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on September 19, 2006, File No. 1-15659).
4.19	Amendment No. 1 to the Registration Rights Agreement dated September 14 2006 by and between Dynegy Inc. and LS Power and affiliates, dated August 9, 2009 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on August 13, 2009, File No. 001-33443).
4.20	Purchase Agreement, dated as of March 29, 2006, for the sale of $750,000,000 aggregate principal amount of the 8.375 percent Senior Unsecured Notes due 2016 of Dynegy Holdings Inc. among Dynegy Holdings Inc. and the several initial purchasers named therein (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2006 of Dynegy Inc., File No. 1-15659).
4.21	Purchase Agreement, dated as of May 17, 2007, by and between Dynegy Holdings Inc. and J.P. Morgan Securities Inc. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for Quarterly Period Ended June 30, 2007 of Dynegy Holdings Inc., File No. 000-29311).
4.22	Exchange Agreement, dated as of July 21, 2006, by and among Dynegy Holdings Inc., RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 2006, File No. 1-15659).
4.23	Registration Rights Agreement dated as of December 1, 2009 by and between Dynegy Holdings Inc. and Adio Bond, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 1, 2009, File No. 001-33443).
4.24	Promissory Note by and between Dynegy Holdings, LLC and Dynegy Gas Investments, LLC dated September 1, 2011 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Holdings, LLC filed on September 8, 2011, File No. 000-29311).
10.1	Note Purchase Agreement by and between Dynegy Holdings Inc. and Adio Bond, LLC, dated August 9, 2009 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on August 13, 2009, File No. 001-33443).

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Exhibit Number	Description
10.2	Purchase Agreement, dated as of December 2, 2009, by and among Credit Suisse Securities (USA) and Citigroup Global Markets Inc. (as representatives for additional purchasers named in the Purchase Agreement), Adio Bond, LLC and Dynegy Holdings Inc. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K by Dynegy Inc. filed on December 7, 2009, File No. 001-33443).
10.3	Credit Agreement, dated as of August 5, 2011, among Dynegy Midwest Generation, LLC, as borrower and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).
10.4	Credit Agreement dated as of August 5, 2011 among Dynegy Power, LLC and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).
10.5	Guarantee and Collateral Agreement, dated as of August 5, 2011 among Dynegy Midwest Generation, LLC, the subsidiaries of the borrower from time to time party thereto and other parties thereto (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).
10.6	Guarantee and Collateral Agreement, dated as of August 5, 2011 among Dynegy Power, LLC, the subsidiaries of the borrower from time to time party thereto and other parties thereto (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).
***10.7	Letter of Credit Reimbursement and Collateral Agreement, dated as of August 5, 2011 among Dynegy Midwest Generation, LLC and Credit Suisse AG, Cayman Islands Branch (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).
10.8	Collateral Trust and Intercreditor Agreement, dated as of August 5, 2011 among Dynegy Coal Investments Holdings, LLC, Dynegy Midwest Generation, LLC, the guarantors and the other parties thereto (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).
10.9	Collateral Trust and Intercreditor Agreement, dated as of August 5, 2011 among Dynegy Gas Investment Holdings, LLC, Dynegy Power LLC, the guarantors and the other parties thereto (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).
***10.10	Letter of Credit Reimbursement and Collateral Agreement, dated as of August 5, 2011 between Dynegy Power LLC and Credit Suisse AG, Cayman Islands Branch (incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).
***10.11	Letter of Credit Reimbursement and Collateral Agreement, dated as of August 5, 2011 between Dynegy Holdings Inc. and Credit Suisse AG, Cayman Islands Branch (incorporated by reference to Exhibit 10.9 to the Current Report on Form 8-K of Dynegy Inc and Dynegy Holdings Inc. filed on August 8, 2011, File No. 001-33443).

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Exhibit Number	Description
***10.12	Letter of Credit Reimbursement and Collateral Agreement, dated as of August 5, 2011 among Dynegy Power LLC and Barclays Bank PLC (incorporated by reference to Exhibit 10.21 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.13	Dynegy Inc. Executive Severance Pay Plan, as amended and restated effective as of January 1, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 4, 2008, File No. 001-33443).
10.14	First Amendment to the Dynegy Inc. Executive Severance Pay Plan effective as of January 1, 2010 (incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2009 of Dynegy Inc, File No. 1-15659).
10.15	Second Amendment to the Dynegy Inc. Executive Severance Pay Plan, dated as of September 20, 2010. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2010 of Dynegy Inc, File No. 1-15659).
10.16	Third Amendment to the Dynegy Inc. Executive Severance Pay Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2011, File No. 1-33443).
10.17	Fourth Amendment to the Dynegy Inc. Executive Severance Pay Plan, dated as of August 8, 2011(incorporated by reference to Exhibit 10. 1 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.18	Dynegy Inc. Executive Change in Control Severance Pay Plan effective April 3, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 8, 1008, File No. 001-33443).
10.19	First Amendment to the Dynegy Inc. Executive Change In Control Severance Pay Plan, dated as of September 22, 2010 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2010 of Dynegy Inc, File No. 1-15659).
10.20	Dynegy Inc. Excise Tax Reimbursement Policy, effective January 1, 2008 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on January 4, 2008, File No. 001-33443).
10.21	Dynegy Inc. Restoration 401(k) Savings Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).
10.22	First Amendment to the Dynegy Inc. Restoration 401(k) Savings Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).
**10.23	Second Amendment to Dynegy Inc. Restoration 401(k) Savings Plan, effective January 1, 2012.
10.24	Dynegy Inc. Restoration Pension Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).

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Exhibit Number	Description
10.25	First Amendment to the Dynegy Inc. Restoration Pension Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).
10.26	Second Amendment to the Dynegy Inc. Restoration Pension Plan, executed on July 2, 2010 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Dynegy Inc. and Dynegy Holdings Inc. filed on August 6, 2010, File No. 000-29311).
**10.27	Third Amendment to Dynegy Inc. Restoration Pension Plan, effective January 1, 2012.
10.28	Form of Phantom Stock Unit Award Agreement Vice President and above, dated March 7, 2011 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2011 of Dynegy Inc., File No. 1- 33443).
10.29	Form of Phantom Stock Unit Award Agreement Managing Director, dated March 7, 2011(incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2011 of Dynegy Inc., File No. 1- 33443).
10.30	Phantom Stock Unit Award Agreement between Dynegy Inc. and E. Hunter Harrison dated June 30, 2011 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1-33443).
10.31	Non-Qualified Stock Option Award Agreement between Dynegy Inc. and Robert C. Flexon date July 11, 2011(incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.32	Stock Appreciation Right Award Agreement between Dynegy Inc. and Robert C. Flexon dated July 11, 2011(incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1-33443).
10.33	Non-Qualified Stock Option Award Agreement between Dynegy Inc. and Kevin T. Howell date July 5, 2011(incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1-33443).
10.34	Non-Qualified Stock Option Award Agreement between Dynegy Inc. and Clint C. Freeland date July 5, 2011(incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.35	Non-Qualified Stock Option Award Agreement between Dynegy Inc. and Carolyn Burke dated August 30, 2011 (incorporated by reference to Exhibit 10. 3 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.36	Non-Qualified Stock Option Award Agreement between Dynegy Inc. and Catherine Callaway dated September 26, 2011 (incorporated by reference to Exhibit 10. 4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.37	Consulting Agreement and Release dated March 8, 2011between Dynegy Inc. and Holli C. Nichols. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K/A of Dynegy Inc. filed on March 10, 2011, File No. 1-33443).

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Exhibit Number	Description
10.38	Severance Agreement and Release by and between Dynegy Inc. and Bruce A. Williamson (incorporated by reference to Exhibit 10.47 to the Annual Report on Form 10-K of Dynegy Inc. for the year ended December 31, 2010, File No. 1-33443).
10.39	Independent Contractor Agreement between Dynegy Inc. and David W. Biegler (incorporated by reference to Exhibit 10.48 to the Annual Report on Form 10-K of Dynegy Inc. for the year ended December 31, 2010, File No. 1-33443).
10.40	Transition Services Agreement between Dynegy Inc. and Lynn Lednicky dated June 28, 2011(incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.41	Employment Agreement between Dynegy Inc. and Robert Flexon dated June 22, 2011(incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.42	Employment Agreement between Dynegy Inc. and Kevin Howell dated June 22, 2011(incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.43	Employment Agreement between Dynegy Inc. and Clint C. Freeland dated June 23, 2011(incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.44	Employment Agreement between Dynegy Inc. and Carolyn J. Burke dated July 5, 2011(incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.45	Employment Agreement between Dynegy Inc. and Catherine Callaway dated September 16, 2011 (incorporated by reference to Exhibit 10. 2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.46	Form Award Agreement for 2012 Long Term Incentive Program Award Cash (CEO) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 9, 2012 File No. 001-33443).
10.47	Form Award Agreement for 2012 Long Term Incentive Program Award Cash (EVP) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on January 9, 2012 File No. 001-33443).
10.48	Dynegy Inc. 2009 Phantom Stock Plan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 10, 2009, File No. 001-33443).
10.49	First Amendment to the Dynegy Inc. 2009 Phantom Stock Plan, dated as of July 8, 2011(incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).
10.50	Dynegy Inc. Deferred Compensation Plan, amended and restated, effective January 1, 2002(incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.51	Amendment to the Dynegy Inc. Deferred Compensation Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.38 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).

Exhibit Number	Description
10.52	Dynegy Inc. Deferred Compensation Plan for Certain Directors, as amended and restated, effective January 1, 2008 (incorporated by reference to Exhibit 10.55 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443).
10.53	Trust under Dynegy Inc. Deferred Compensation Plan for Certain Directors, effective January 1, 2009 (incorporated by reference to Exhibit 10.56 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443).
10.54	Dynegy Inc. Incentive Compensation Plan, as amended and restated effective May 21, 2010 (incorporated by reference to Exhibit 10.34 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2010, File No. 001-33443)
10.55	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, File No. 333-167091).
10.56	Dynegy Inc. 2000 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156).
10.57	Amendment to the Dynegy Inc. 2000 Long Term Incentive Plan effective January 1, 2006 (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.58	Second Amendment to the Dynegy Inc. 2000 Long Term Incentive Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.34 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.59	Dynegy Inc. 2002 Long Term Incentive Plan (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 9, 2002).
10.60	Amendment to the Dynegy Inc. 2002 Long Term Incentive Plan, effective January 1, 2006 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.61	Second Amendment to the Dynegy Inc. 2002 Long Term Incentive Plan, dated as of April 2, 2007 (incorporated by reference to Exhibit 10.36 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.62	Dynegy Inc. Deferred Compensation Plan Trust Agreement (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080).
10.63	Amendment to Dynegy Inc. Deferred Compensation Plan Trust Agreement (Vanguard), dated as of April 2, 2007 (incorporated by reference to Exhibit 10.54 to the Current Report on Form 8-K of Dynegy Holdings Inc. filed on April 6, 2007, File No. 000-29311).
10.65	Baldwin Consent Decree, approved May 27, 2005 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 31, 2005, File No. 1-15659).

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Exhibit Number	Description
10.66	Letter Agreement dated March 8, 2011 by and between Dynegy Inc. and IEH Merger Sub LLC, Icahn Enterprises Holdings L.P., IEP Merger Sub Inc., Icahn Partners LP, Icahn Partners Master Fund LP, Icahn Partners Master Fund II LP, Icahn Partners Master Fund III LP, High River Limited Partnership, Hopper Investments LLC, Barberry Corp., Icahn Onshore LP, Icahn Offshore LP, Icahn Capital LP, IPH GP LLC, Icahn Enterprises L.P., Icahn Enterprises G.P. Inc., Beckton Corp., and Carl C. Icahn. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 10, 2011, File No. 1-33443).
10.67	Assignment Agreement by and among Dynegy Gas Investments, LLC, Dynegy Holdings, LLC and Dynegy Inc. dated September 1, 2011 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Holdings, LLC filed on September 8, 2011, File No. 000-29311).
10.68	Restructuring Support Agreement, dated November 7, 2011, among Dynegy Inc., Dynegy Holdings, LLC and certain beneficial holders of notes issued by Dynegy Holdings, LLC (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on November 8, 2011, File No. 001-33443).
10.69	First Amendment to the Restructuring Support Agreement, dated December 9, 2011 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on December 9, 2011, File No. 001-33443).
10.70	Second Amendment to the Restructuring Support Agreement, dated December 16, 2011 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on December 20, 2011, File No. 001-33443).
10.71	Amended and Restated Restructuring Support Agreement, dated December 26, 2011 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on December 27, 2011, File No. 001-33443).
10.72	Chapter 11 Plan of Reorganization for Dynegy Holdings, LLC proposed by Dynegy Holdings, LLC and Dynegy Inc., dated December 1, 2011 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on December 2, 2011, File No. 001-33443).
10.73	Amended Chapter 11 Plan of Reorganization for Dynegy Holdings, LLC proposed by Dynegy Holdings, LLC and Dynegy Inc., dated January 19, 2012 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on January 23, 2012, File No. 001-33443).
10.74	Second Amended Chapter 11 Plan of Reorganization for Dynegy Holdings, LLC proposed by Dynegy Holdings, LLC and Dynegy Inc., dated March 6, 2012 (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on March 7, 2012, File No. 001-33443).
10.75	Description of the Plan Secured Notes, as Exhibit C to the Plan of Reorganization, dated December 23, 2011 (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on December 27, 2011, File No. 001-33443).

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Exhibit Number	Description
10.76	Description of the Plan Secured Notes, as Exhibit C to the Amended Plan of Reorganization, dated January 19, 2012 (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on January 23, 2012, File No. 001-33443).
10.77	Description of the Plan Secured Notes, as Exhibit C to the Second Amended Plan of Reorganization, dated March 6, 2012 (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on March 7, 2011, File No. 001-33443).
10.78	Certificate of Designation for the Plan Preferred Stock, as Exhibit D to the Plan of Reorganization dated December 23, 2011 (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on December 27, 2011, File No. 001-33443).
10.79	Certificate of Designation for the Plan Preferred Stock, as Exhibit D to the Second Amended Plan of Reorganization, dated March 6, 2012 (incorporated by reference to Exhibit 99.4 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on March 7, 2012, File No. 001-33443).
10.80	Disclosure Statement Related to the Chapter 11 Plan of Reorganization for Dynegy Holdings, LLC Proposed by Dynegy Holdings, LLC and Dynegy Inc. (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on December 2, 2011, File No. 001-33443).
10.81	Disclosure Statement Related to the Amended Chapter 11 Plan of Reorganization for Dynegy Holdings, LLC Proposed by Dynegy Holdings, LLC and Dynegy Inc., dated January 19, 2012 (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on January 23, 2012, File No. 001-33443).
10.82	Disclosure Statement Related to the Second Amended Chapter 11 Plan of Reorganization for Dynegy Holdings, LLC Proposed by Dynegy Holdings, LLC and Dynegy Inc., dated March 6, 2012 (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on March 7, 2012, File No. 001-33443).
10.83	Dynegy Inc., Dynegy Holdings, LLC and certain of its affiliates and subsidiaries and Resources Capital Management Corporation and certain of its affiliates and subsidiaries Binding Term Sheet, dated December 13, 2011 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on December 14, 2011, File No. 001-33443).
14.1	Dynegy Inc. Code of Ethics for Senior Financial Professionals, as amended on November 16, 2011 (incorporated by reference to Exhibit 14.1 to the Current Report on Form 8-K filed on November 17, 2011 File No. 001-33443).
**21.1	Subsidiaries of the Registrant (Dynegy Inc.).
**23.1	Consent of Ernst & Young LLP (Dynegy Inc.).
**23.2	Consent of Ernst & Young LLP Dynegy Holdings, LLC as of December 31, 2011 and for the period from November 8, 2011 through December 31, 2011.

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Exhibit Number	Description
**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.
**31.2	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.
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.
32.2	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.
*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

*

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 1934, 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.

**

Filed herewith

***

Certain exhibits, attachments or schedules to the exhibits filed herewith were never prepared or used by the parties in connection with the transactions which are the subject of the filed exhibit and therefore no actual exhibit, attachment or schedule exists.

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

Management contract or compensation plan.

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SIGNATURES

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

DYNEGY INC.

Date: March 8, 2012

By: /s/ ROBERT C. FLEXON

Robert C. Flexon
President and Chief Executive Officer

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

/s/ ROBERT C. FLEXON Robert C. Flexon	President and Chief Executive Officer (Principal Executive Officer)	March 8, 2012
/s/ CLINT C. FREELAND Clint C. Freeland	Executive Vie President and Chief Financial Officer (Principal Financial Officer)	March 8, 2012
/s/ CAROLYN J. STONE Carolyn J. Stone	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 8, 2012
/s/ THOMAS W. ELWARD Thomas W. Elward	Chairman of the Board	March 8, 2012
/s/ MICHAEL J. EMBLER Michael J. Embler	Director	March 8, 2012
/s/ VINCENT J. INTRIERI Vincent J. Intrieri	Director	March 8, 2012
/s/ SAMUEL MERKSAMER Samuel Merksamer	Director	March 8, 2012
/s/ FELIX PARDO Felix Pardo	Director	March 8, 2012

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DYNEGY INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

* Dynegy Holdings, LLC consolidated financial statements for the period from November 8, 2011 through December 31, 2011 are included herein pursuant to Rule 3-09 of Regulation S-X.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.

We have audited the accompanying consolidated balance sheets of Dynegy Inc. as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive loss, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15(a). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Dynegy Inc. at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 16 to the consolidated financial statements, effective January 1, 2010 the Company adopted authoritative guidance issued by the Financial Accounting Standards Board for variable interest entities.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Dynegy Inc.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 8, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 8, 2012

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DYNEGY INC.

CONSOLIDATED BALANCE SHEETS

(in millions, except share data)

	December 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	$ 396	$ 291
Restricted cash and investments	69	81
Short-term investments		106
Accounts receivable, net of allowance for doubtful accounts of $19 and $32, respectively	6	230
Accounts receivable, affiliates	47	1
Inventory	57	121
Assets from risk-management activities	65	1,199
Assets from risk-management activities, affiliates	4	
Deferred income taxes	5	12
Broker margin account	10	80
Prepayments and other current assets	13	123
Total Current Assets	672	2,244
Property, Plant and Equipment	4,878	8,593
Accumulated depreciation	(1,544)	(2,320)
Property, Plant and Equipment, Net	3,334	6,273
Other Assets		
Unconsolidated investment (Note 15)		
Restricted cash and investments	103	859
Assets from risk-management activities	1	72
Assets from risk-management activities, affiliates	3	
Intangible assets		141
Other long-term assets	14	424
Total Assets	$ 4,127	$ 10,013
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 15	$ 134
Accounts payable, affiliates	26	
Accrued interest		36
Accrued interest, affiliates	8	
Accrued liabilities and other current liabilities	40	109
Liabilities from risk-management activities	64	1,138
Liabilities from risk-management activities, affiliates	2	
Current portion of long-term debt	4	148
Total Current Liabilities	159	1,565
Long-term debt	584	4,426
Long-term debt to affiliates	1,250	200
Long-Term Debt	1,834	4,626
Other Liabilities		
Accounts payable, affiliates	870	
Liabilities from risk-management activities	2	99
Deferred income taxes	5	641
Other long-term liabilities	145	336

Total Liabilities		3,015		7,267
Commitments and Contingencies (Note 23)				
Stockholders' Equity				
Common Stock, $0.01 par value, 420,000,000 shares authorized at December 31, 2011 and December 31, 2010; 123,585,877 shares and 121,687,198 shares issued and outstanding at December 31, 2011 and December 31, 2010, respectively		1		1
Additional paid-in capital		6,077		6,067
Subscriptions receivable		(2)		(2)
Accumulated other comprehensive loss, net of tax		(53)		(53)
Accumulated deficit		(4,841)		(3,196)
Treasury stock, at cost, 731,407 shares and 628,014 shares at December 31, 2011 and December 31, 2010, respectively		(70)		(71)
Total Stockholders' Equity		1,112		2,746
Total Liabilities and Stockholders' Equity	$	4,127	$	10,013

See the notes to the consolidated financial statements.

DYNEGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Year Ended December 31, 2011	2010	2009
Revenues	$ 1,585	$ 2,323	$ 2,468
Cost of sales	(963)	(1,181)	(1,194)
Gross margin, exclusive of depreciation shown separately below	622	1,142	1,274
Operating and maintenance expense, exclusive of depreciation shown separately below	(393)	(450)	(519)
Depreciation and amortization expense	(325)	(392)	(335)
Goodwill impairments			(433)
Impairment and other charges, exclusive of goodwill impairments shown separately above	(6)	(148)	(538)
Gain (loss) on sale of assets, net	1		(124)
General and administrative expenses	(135)	(163)	(159)
Operating loss	(236)	(11)	(834)
Losses from unconsolidated investments		(62)	(71)
Loss on deconsolidation of DH (Note 3)	(1,657)		
Interest expense	(357)	(363)	(415)
Debt extinguishment costs	(21)		(46)
Other income and expense, net	(6)	4	11
Loss from continuing operations before income taxes	(2,277)	(432)	(1,355)
Income tax benefit	632	197	315
Loss from continuing operations	(1,645)	(235)	(1,040)
Income (loss) from discontinued operations, net of tax benefit (expense) of zero, zero and $121, respectively (Note 5)		1	(222)
Net loss	(1,645)	(234)	(1,262)
Less: Net loss attributable to the noncontrolling interests			(15)
Net loss attributable to Dynegy Inc.	$ (1,645)	$ (234)	$ (1,247)
Earnings (Loss) Per Share (Note 22):			
Basic earnings (loss) per share attributable to Dynegy Inc.:			
Earnings (loss) from continuing operations	$ (13.48)	$ (1.96)	$ (6.25)
Income (loss) from discontinued operations		0.01	(1.35)
Basic earnings (loss) per share attributable to Dynegy Inc.	$ (13.48)	$ (1.95)	$ (7.60)
Diluted earnings (loss) per share attributable to Dynegy Inc.:			
Earnings (loss) from continuing operations	$ (13.48)	$ (1.96)	$ (6.25)
Income (loss) from discontinued operations		0.01	(1.35)
Diluted earnings (loss) per share attributable to Dynegy Inc.	$ (13.48)	$ (1.95)	$ (7.60)
Basic shares outstanding	122	120	164
Diluted shares outstanding	122	121	165

See the notes to the consolidated financial statements.

DYNEGY INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in millions)

	Year Ended December 31,		
	2011	2010	2009
Net loss	$ (1,645)	$ (234)	$ (1,262)
Cash flow hedging activities, net:			
Unrealized mark-to-market gains arising during period, net			166
Reclassification of mark-to-market (gains) losses to earnings, net	(1)		1
Deferred losses on cash flow hedges, net			(11)
Changes in cash flow hedging activities, net (net of tax benefit (expense) of $1, zero, and $(24), respectively)	(1)		156
Actuarial gain and amortization of unrecognized prior service cost (net of tax expense of $(1), $(1), and $(8), respectively)	1	3	7
Unconsolidated investment other comprehensive loss, net (net of tax benefit (expense) of zero, $(11) and $17, respectively)		17	24
Other comprehensive income, net of tax		20	187
Comprehensive loss	(1,645)	(214)	(1,075)
Less: Comprehensive income attributable to the noncontrolling interests			107
Comprehensive loss attributable to Dynegy Inc.	$ (1,645)	$ (214)	$ (1,182)

See the notes to the consolidated financial statements.

DYNEGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31,		
	2011	**2010**	**2009**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (1,645)	$ (234)	$ (1,262)
Adjustments to reconcile loss to net cash flows from operating activities:			
Depreciation and amortization	346	408	359
Goodwill impairments			433
Loss on deconsolidation of DH	1,657		
Impairment and other charges, exclusive of goodwill impairments shown separately above	12	136	796
Losses from unconsolidated investments, net of cash distributions		62	72
Risk-management activities	157	(19)	180
Risk management activities, affiliates	5		
Loss (gain) on sale of assets, net	(1)		218
Deferred taxes	(632)	(195)	(436)
Debt extinguishment costs	21		46
Other	43	73	84
Changes in working capital:			
Accounts receivable	49	(16)	66
Inventory	(3)	16	7
Broker margin account	(74)	290	(201)
Prepayments and other assets	(1)	(8)	15
Accounts payable and accrued liabilities	105	(18)	(112)
Affiliate transactions	16		
Changes in non-current assets	(77)	(67)	(119)
Changes in non-current liabilities	2	(5)	(11)
Net cash provided by (used in) operating activities	(20)	423	135
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(242)	(333)	(612)
Deconsolidation of DH	(303)		
Unconsolidated investments		(15)	1
Proceeds from asset sales, net			652
Maturities of short-term investments	475	317	
Purchases of short-term investments	(284)	(508)	
Decrease (increase) in restricted cash	88	(3)	190
Other investing, net	12	8	20
Net cash provided by (used in) investing activities	(254)	(534)	251
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings, net of financing costs	2,020	(6)	328
Repayments of borrowings	(1,624)	(63)	(890)
Debt extinguishment costs	(21)		(46)
Net proceeds from issuance of capital stock	3		
Other financing, net	1		
Net cash provided by (used in) financing activities	379	(69)	(608)

Net increase (decrease) in cash and cash equivalents	105	(180)	(222)
Cash and cash equivalents, beginning of period	291	471	693
Cash and cash equivalents, end of period	$ 396	$ 291	$ 471

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(in millions)

	Common Stock	Additional Paid-In Capital	Subscriptions Receivable	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Treasury Stock	Total Controlling Interests	Noncontrolling Interests	Total
December 31, 2008	$ 3	$ 6,490	$ (2)	$ (215)	$ (1,690)	$ (71)	$ 4,515	$ (30)	$ 4,485
Net loss					(1,247)		(1,247)	(15)	(1,262)
Other comprehensive income, net of tax				65			65	122	187
401(k) plan and profit sharing stock		5					5		5
Board of directors stock compensation		(1)					(1)		(1)
Retirement of Class B common stock (Note 24)	(2)	(441)					(443)		(443)
Options and restricted stock granted		8					8		8
December 31, 2009	$ 1	$ 6,061	$ (2)	$ (150)	$ (2,937)	$ (71)	$ 2,902	$ 77	$ 2,979
Deconsolidation of Plum Point (See Note 16)				77	(25)		52	(77)	(25)
Net loss					(234)		(234)		(234)
Other comprehensive income, net of tax				20			20		20
401(k) plan and profit sharing stock		6					6		6
December 31, 2010	$ 1	$ 6,067	$ (2)	$ (53)	$ (3,196)	$ (71)	$ 2,746	$	$ 2,746
Net loss					(1,645)		(1,645)		(1,645)
Other comprehensive income, net of tax									
Options and restricted stock granted		6				1	7		7
401(k) plan and profit sharing stock		4					4		4
December 31, 2011	$ 1	$ 6,077	$ (2)	$ (53)	$ (4,841)	$ (70)	$ 1,112	$	$ 1,112

See the notes to the consolidated financial statements.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Operations

We are a holding company 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 segments in our consolidated financial statements: (i) the Coal segment ("Coal"); (ii) the Gas segment ("Gas") and (iii) the Dynegy Northeast segment ("DNE"). Prior to 2011, we reported results for the following segments: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Our consolidated financial results also reflect corporate-level expenses such as interest and depreciation and amortization. General and administrative expenses are allocated to each reportable segment. Accordingly, we have recast the corresponding items of segment information for all prior periods.

With the commencement of the Chapter 11 Cases (as defined below), Dynegy Holdings, LLC ("DH") and its direct and indirect subsidiaries were deconsolidated effective November 7, 2011. Financial statements presented after November 7, 2011 reflect our investment in, and the results of operations of, DH and its wholly-owned subsidiaries under the equity method of accounting. For further discussion, please read Note 3 Chapter 11 Cases Accounting Impact.

Chapter 11 Filing by Certain Subsidiaries. On November 7, 2011, DH and four of its wholly-owned subsidiaries, Dynegy Northeast Generation, Inc., Hudson Power, L.L.C., Dynegy Danskammer, L.L.C. and Dynegy Roseton, L.L.C. (collectively, the "Debtor Entities") filed voluntary petitions (the "Chapter 11 Cases") for relief under Chapter 11 of Title 11 of the United States Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of New York, Poughkeepsie Division (the "Bankruptcy Court"). The Chapter 11 Cases were assigned to the Honorable Cecelia G. Morris and are being jointly administered for procedural purposes only. Dynegy and its subsidiaries, other than the five Debtor Entities, did not file voluntary petitions for relief and are not debtors under Chapter 11 of the Bankruptcy Code and, consequently, continue to operate their business in the ordinary course.

Reorganization. On August 5, 2011, we completed an internal reorganization (the "Reorganization") to eliminate our regional organizational structure and create separate coal-fired power generation and natural gas-fired power generation units as a result of which, (i) substantially all of our indirect wholly-owned coal-fired power generation facilities are held by Dynegy Midwest Generation, LLC ("DMG"), (ii) substantially all of our indirect wholly-owned natural gas- fueled power generation facilities are held by Dynegy Power, LLC ("DPC"), and (iii) 100 percent of our indirect ownership interests in Dynegy Northeast Generation, Inc., the entity that indirectly holds the equity interest in Dynegy Roseton, L.L.C. and Dynegy Danskammer, L.L.C. are held by DH. As noted above, following such reorganization, Dynegy's operations were reorganized into three segments: (i) Coal, (ii) Gas, and (iii) DNE.

On August 5, 2011, DPC and its parent Dynegy Gas Investments Holdings, LLC ("DGIH"), each an indirect subsidiary of DH, entered into a $1.1 billion, five-year senior secured term loan facility (the "DPC Credit Agreement"). The same day, DMG and its parent Dynegy Coal Investments Holdings, LLC, each then also an indirect subsidiary of DH, entered into a $600 million, five-year senior secured term loan facility (the "DMG Credit Agreement" and together with the DPC Credit Agreement, the "New Credit Agreements"). Proceeds from these New Credit Agreements enabled DH to repay its outstanding indebtedness under DH's Fifth Amended and Restated Credit Agreement, and are available to DPC and DMG to be used for general working capital and general corporate purposes. Please read Note 19 Debt DMG Credit Agreement and DH Debt Obligations DPC Credit

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 1 Organization and Operations (Continued)

Agreement for further discussion. Our remaining assets (including our leasehold interests in the Danskammer and Roseton facilities) are not a part of either DPC or DMG.

DMG Transfer. On September 1, 2011, Dynegy and Dynegy Gas Investments, LLC ("DGIN"), a subsidiary of DH, entered into a Membership Interest Purchase Agreement whereby DGIN transferred 100 percent of its outstanding membership interests of Dynegy Coal HoldCo, LLC ("Coal HoldCo"), a Delaware limited liability company which through DMG owns Dynegy's portfolio of primarily coal-fired generation facilities, to Dynegy (the "DMG Transfer"). In exchange for Coal HoldCo, Dynegy agreed to make certain specified payments (aggregating approximately $2.1 billion through October 15, 2026) to DGIN over time which coincide in timing and amount to the payments of principal and interest that DH is obligated to make with respect to a portion of certain of DH's senior unsecured notes and debentures (the "Undertaking Agreement"). DGIN assigned its rights to receive payments under the Undertaking Agreement to DH in exchange for a promissory note (the "Promissory Note") in the amount of $1.25 billion that matures in 2027 (the "Assignment"). As a condition to Dynegy's consent to the Assignment, the Undertaking Agreement was amended and restated to be between DH and Dynegy and to provide for the reduction of Dynegy's obligations if the outstanding principal amount of DH's senior unsecured notes and debentures decreases as a result of any exchange offer, tender offer or other purchase or repayment by Dynegy or its subsidiaries (other than DH and its subsidiaries, unless Dynegy guarantees the debt securities of DH or such subsidiary in connection with such exchange offer, tender offer or other purchase or repayment); provided that such principal amount is retired, cancelled or otherwise forgiven. Upon the Effective Date, Dynegy and DH will cancel the Undertaking Agreement and Dynegy's obligations under the Undertaking Agreement will be fully satisfied and extinguished.

There was no initial impact on our consolidated financial position, results of operations or cash flows related to the DMG Transfer as the transaction was between us and our wholly-owned subsidiaries. However, as a result of the deconsolidation of DH for accounting purposes (as further discussed in Note 3 Chapter 11 Cases), the Undertaking payable to DH is reflected as a long-term obligation with an affiliate on our consolidated balance sheet and the interest expense associated with the Undertaking is reflected in interest expense on our consolidated statement of operations. For further discussion, please read Note 20 Related Party Transactions Undertaking Agreement.

Basis of Presentation. We previously disclosed in our 2010 Form 10-K our plans to continue as a going concern, due primarily to concerns regarding lower power prices and potential noncompliance with financial covenants contained in DH's former Fifth Amended and Restated Credit Agreement. During 2011, while lower power prices continued, we have accomplished certain significant milestones which have improved our liquidity projections and allowed us to continue as a going concern. These milestones include:

- DMG and DPC entered into the New Credit Agreements on August 5, 2011 which resulted in the repayment in full and termination of commitments under DH's former Fifth Amended and Restated Credit Agreement.

- We initiated a new cost and performance improvement initiative, known as PRIDE, which is designed to drive recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 1 Organization and Operations (Continued)

The Debtor Entities filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code allowing for the restructuring of our long-term debt and lease obligations. As a result, we deconsolidated DH and its subsidiaries as we concluded, under applicable accounting standards, we no longer have a controlling financial interest in DH and its wholly-owned subsidiaries. Effective with the deconsolidation and write down of our investment in DH, we no longer included DH and its subsidiaries' assets or liabilities in our liquidity analysis with respect to Dynegy Inc.'s accompanying financial statements. If the Plan is approved by the bankruptcy court, we will re-assess consolidation of DH and its subsidiaries at that time.

We believe we have the ability to continue as a going concern through at least 2012; however, the ultimate outcome of the Chapter 11 Cases and the impact to us is uncertain at this time. Please read Note 3 Chapter 11 Cases, Note 20 Related Party Transactions Transactions with DH Accounts payable, affiliates and Note 23 Commitments and Contingencies for further discussion.

Note 2 Summary of Significant Accounting Policies

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

Principles of Consolidation. The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries and VIEs for which we are the primary beneficiary. Intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to prior-period amounts to conform with current-period presentation.

Effective November 7, 2011 with the commencement of the Chapter 11 Cases, Dynegy deconsolidated its investment in DH. Please read Note 3 Chapter 11 Cases Accounting Impact and Note 16 Variable Interest Entities DH for further discussion.

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

Restricted Cash and Investments. Restricted cash and investments represent cash that is not readily available for general purpose cash needs. Restricted cash and investments are classified as a current or long-term asset based on the timing and nature of when or how the cash is expected to be used or when the restrictions are expected to lapse. We include all changes in restricted cash and investments in investing cash flows on the consolidated statements of cash flows. Please read Note 19 Debt Restricted Cash and Investments for further discussion.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

Accounts Receivable and Allowance for Doubtful Accounts. We record accounts receivable at the net realizable value when the product or service is delivered to the customer. We establish provisions for losses on accounts receivable if it becomes probable we will not collect all or part of outstanding balances. We review collectability and establish or adjust our allowance as necessary. We primarily use a percent of balance methodology and methodologies involving historical levels of write-offs. The specific identification method is also used in certain circumstances.

Unconsolidated Investments. Effective November 7, 2011, we began using the equity method of accounting for our wholly-owned subsidiary, DH, as a result of the Chapter 11 Cases. Please read Note 3 Chapter 11 Cases Accounting Impact and Note 16 Variable Interest Entities DH for further discussion. In addition, we use the equity method of accounting for investments in affiliates over which we exercise significant influence, generally occurring in ownership interests of 20 percent to 50 percent, and also occurring in lesser ownership percentages due to voting rights or other factors and VIEs where we are not the primary beneficiary. Our share of net income (loss) from these affiliates is reflected in the consolidated statements of operations as earnings (losses) from unconsolidated investments. Any excess of our investment in affiliates, as compared to our share of the underlying equity that is not recognized as goodwill, that represents identifiable other intangible assets, is amortized over the estimated economic service lives of the underlying assets, or, in the instances where the useful lives cannot be determined, the excess is assessed each reporting period for impairment or to determine if the useful life can be estimated. All investments in unconsolidated affiliates are periodically assessed for other-than-temporary declines in value, with write-downs recognized in earnings from unconsolidated investments in the consolidated statements of operations.

Please read Note 8 Impairment and Restructuring Charges for a discussion of impairment charges we recognized in 2010 related to our investment in Plum Point and Note 5 Dispositions, Contract Terminations and Discontinued Operations for a discussion of losses recognized related to the sale of our investment in the Sandy Creek Project.

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.

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) in the consolidated statements of 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 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 consolidated statements of operations and any remaining impairment is recognized

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

in Other comprehensive 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 December 31, 2010, we held $191 million of available for sale securities with maturity dates within one year. Of this amount, $85 million was included in the Broker margin account on our consolidated balance sheets as of December 31, 2010.

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. At December 31, 2011, we did not hold any short-term investments.

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

We may opportunistically sell emissions allowances, subject to certain regulatory limitations and restrictions contained in our Consent Decree, or hold them in inventory until they are needed. In the past, we have sold emission allowances that relate to future periods. To the extent the proceeds received from the sale of such allowances exceed our cost, we defer the associated gain until the period to which the allowance relates, as we may be required to purchase emissions allowances in future periods. As of December 31, 2011, we had aggregate deferred gains of $7 million, which was included in Other long-term liabilities in our consolidated balance sheets. As of December 31, 2010, we had aggregate deferred gains of $9 million, which was included in Accrued liabilities and other current liabilities and Other long-term liabilities in our consolidated balance sheets. We recognized zero, $3 million and $22 million in revenue for the years ended December 31, 2011, 2010 and 2009, respectively, related to sales of emissions credits.

Property, Plant and Equipment. Property, plant and equipment, which consists principally of power generating facilities, including capitalized interest, is recorded at historical cost. Expenditures for major replacements, renewals and major maintenance are capitalized and depreciated over the expected maintenance cycle. We consider major maintenance to be expenditures incurred on a cyclical basis to maintain and prolong the efficient operation of our assets. Expenditures for repairs and minor renewals to maintain assets in operating condition are expensed. Depreciation is provided using the straight-line method over the estimated economic service lives of the assets, ranging from 3 to 40 years.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

Composite depreciation rates (which we refer to as composite rates) are applied to functional groups of assets having similar economic characteristics. The estimated economic service lives of our functional asset groups are as follows:

Asset Group	Range of Years
Power generation facilities	7 to 40
Buildings and improvements	10 to 39
Office and miscellaneous equipment	3 to 20

Gains and losses on sales of individual assets or asset groups are reflected in Gain (loss) on sale of assets, net, in the consolidated statements of operations. We assess the carrying value of our property, plant and equipment to determine if an impairment is indicated when a triggering event occurs. If an impairment is indicated, the amount of the impairment loss recognized would be determined by the amount by which the book value exceeds the estimated fair value of the assets. The estimated fair value may include estimates based upon discounted cash-flow projections, recent comparable market transactions or quoted prices to determine if an impairment loss is required. For assets identified as held for sale, the book value is compared to the estimated sales price less costs to sell.

Please read Note 8 Impairment and Restructuring Charges for a discussion of impairment charges we recognized in 2011, 2010 and 2009.

In accordance with our policy, we review fixed assets for known facts that potentially would impact their estimated useful lives. Based on events occurring in September 2010, we determined that it was not economical to continue to operate our Vermilion facility for the remainder of its estimated useful life. As a result, effective September 1, 2010, we changed our estimate of the useful life of this facility to better reflect the estimated periods during which we expected the asset would remain in service. The facility's previously estimated remaining useful life of 15 years was adjusted to reflect an expected retirement date of April 30, 2011. At December 31, 2010, we further adjusted the estimated useful life of the facility based on an expected retirement date of March 31, 2011. The effect of these changes in estimate was to increase depreciation expense by approximately $56 million ($34 million net of tax), or $0.28 per share (basic and diluted), for the year ended December 31, 2010. The Vermilion facility was permanently retired in 2011.

Goodwill and Other Intangible Assets. Goodwill represents, at the time of an acquisition, the amount of purchase price paid in excess of the fair value of net assets acquired. We previously assessed the carrying value of our goodwill for impairment on an annual basis on November 1st, and when events warranted an assessment. Our evaluation was based, in part, on our estimate of future cash flows, recent market comparable transactions, and earnings multiples of similarly situated public companies. The estimation of fair value is highly subjective, inherently imprecise and can change materially from period to period based on, among other things, an assessment of market conditions, projected cash flows and discount rates. Please read Note 17 Goodwill for further discussion of our impairment analysis. Our goodwill balance was fully impaired at March 31, 2009.

Intangible assets represent the fair value of assets, apart from goodwill, that arise from contractual rights or other legal rights. We record only those intangible assets that are distinctly separable from goodwill and can be sold, transferred, licensed, rented, or otherwise exchanged in the open market.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

Additionally, we recognize as intangible assets those assets that can be exchanged in combination with other rights, contracts, assets or liabilities.

We initially record and measure intangible assets based on the fair value of those rights transferred in the transaction in which the asset was acquired. Those measurements are based on quoted market prices for the asset, if available, or measurement techniques based on the best information available such as a present value of future cash flows. Present value measurement techniques involve judgments and estimates made by management about prices, cash flows, discount factors and other variables, and the actual value realized from those assets could vary materially from these judgments and estimates. We amortize our definite-lived intangible assets based on the useful life of the respective asset as measured by the life of the underlying contract or contracts. Intangible assets that are not subject to amortization are subjected to impairment testing on an annual basis or when a triggering event occurs, and an impairment loss is recognized if the carrying amount of an intangible asset exceeds its fair value.

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

	Year Ended December 31,		
	2011	2010	2009
	(in millions)		
Beginning of year	$ 120	$ 120	$ 127
Accretion expense	7	10	13
Divestiture of assets			(6)
Deconsolidation of DH (1)	(71)		
Revision of previous estimate (2)	(14)	(10)	(14)
End of year	$ 42	$ 120	$ 120

(1) As a result of the deconsolidation of DH, the ARO obligations related to our Gas and DNE segments are no longer reflected as liabilities on our consolidated balance sheet but are instead considered in our investment in DH. Please read Note 3 Chapter 11 Cases Accounting Impact for further discussion.

(2) During 2011, we revised our ARO obligation downward by $14 million based on revised cost estimates related to remediation of asbestos. During 2010, we revised our ARO obligation downward by $5 million based on revisions to the timing of the remediation obligations within our Coal fleet and by $5 million at the Danskammer facility based on revised cost estimates. In addition, we revised our ARO obligation downward by

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

$14 million in 2009 based on revised estimates of the cost to dismantle the South Bay facility.

We may have additional potential retirement obligations for dismantlement of power generation facilities. Our current intent is to maintain these facilities in a manner such that they will be operated indefinitely. As a result, we cannot estimate any potential retirement obligations associated with these assets. Liabilities will be recorded at the time we are able to estimate these AROs.

Contingencies, Commitments, Guarantees and Indemnifications. We are involved in numerous lawsuits, claims, proceedings and tax-related audits in the normal course of our operations. We record a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an ongoing basis to ensure that we have appropriate reserves recorded on our consolidated balance sheets. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant. Our estimates and judgment could change based on new information, changes in laws or regulations, changes in management's plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from these estimates and judgments.

Liabilities for environmental contingencies are recorded when an environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability.

These assumptions involve the judgments and estimates of management, and any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

We disclose and account for various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification is entered into, an estimated fair value of the underlying guarantee or indemnification is recorded. Some guarantees and indemnifications could have significant financial impact under certain circumstances; however, management also considers the probability of such circumstances occurring when estimating the fair value. Actual results may materially differ from the estimated fair value of such guarantees and indemnifications.

Revenue Recognition. We earn revenue from our facilities in three primary ways: (i) the sale of both fuel and energy through both physical and financial transactions to optimize the financial performance of our generating facilities; (ii) sale of capacity; and (iii) sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative. Please read " Derivative Instruments Generation" for further discussion of the accounting for these types of transactions.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

Derivative Instruments Generation. We enter into commodity contracts that meet the definition of a derivative. These contracts are often entered into to mitigate or eliminate market and financial risks associated with our generation business. These contracts include forward contracts, which commit us to sell commodities in the future; futures contracts, which are generally exchange-traded standard commitments to purchase or sell a commodity; option contracts, which convey the right to buy or sell a commodity; and swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined quantity. There are three different ways to account for these types of contracts: (i) as an accrual contract, if the criteria for the "normal purchase normal sale" exception are met and documented; (ii) as a cash flow or fair value hedge, if the specified criteria are met and documented; or (iii) as a mark-to-market contract with changes in fair value recognized in current period earnings. All derivative commodity contracts that do not qualify for the normal purchase normal sale exception are recorded at fair value in risk management assets and liabilities on the consolidated balance sheets. If the derivative commodity contract has been designated as a cash flow hedge, the changes in fair value are recognized in earnings concurrent with the hedged item. Changes in the fair value of derivative commodity contracts that are not designated as cash flow hedges are recorded currently in earnings.

We execute a significant volume of transactions through futures clearing managers. Our daily cash payments (receipts) to (from) our futures clearing managers consist of three parts: (i) fair value of open positions (exclusive of options) ("Daily Cash Settlements"); (ii) initial margin requirements of open positions ("Initial Margin"); and (iii) fair value related to options ("Options," and collectively with Daily Cash Settlements and 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 Collateral, as applicable, on a gross basis.

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

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

Fair Value Measurements. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, we utilize a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of our financial assets and liabilities measured and reported at fair value. Where appropriate, our estimate of fair value reflects the impact of our credit risk, our counterparties' credit risk and bid-ask spreads. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observability of those inputs. The inputs used to measure fair value have been placed in a hierarchy based on priority.

The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

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

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

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to our needs as well as financial transmission rights. At each balance sheet date, we perform an analysis of all instruments and include in Level 3 all of those whose fair value is based on significant unobservable inputs.

The determination of the fair values incorporates various factors. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities. Valuation adjustments are generally based on capital market implied ratings evidence when assessing the credit standing of our counterparties and when applicable, adjusted based on management's estimates of assumptions market participants would use in determining fair value.

Assets and liabilities from risk management activities may include exchange-traded derivative contracts and OTC derivative contracts. Some exchange-traded derivatives are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets. In such cases, these exchange-traded derivatives are classified within Level 2. OTC derivative trading instruments include swaps, forwards, options and complex structures that are valued at fair value. In certain instances, these instruments may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that

Note 2 Summary of Significant Accounting Policies (Continued)

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.

In determining fair value for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis, we use discounted cash-flow projections, recent comparable market transactions, if available, or quoted prices. We consider assumptions that third parties would make in estimating fair value, including the highest and best use of the asset. These fair values are categorized in Level 3.

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

Income Taxes. We use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

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

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

We do not believe we will produce sufficient future taxable income, nor are there tax planning strategies available to realize the tax benefits from, net deferred tax assets not otherwise realized by reversing temporary differences. Therefore, a valuation allowance was recorded as of December 31, 2011. Any change in the valuation allowance would impact our income tax benefit (expense) and net income (loss) in the period in which the change occurs.

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

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

Please read Note 21 Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions and changes in our valuation allowance.

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

Employee Stock Options. We use the fair-value based method of accounting for stock-based employee compensation and we used the prospective method of transition for stock options granted. Under the prospective method of transition, all stock options granted after January 1, 2003 were accounted for on a fair value basis. Options granted prior to January 1, 2003 continued to be accounted for using the intrinsic value method. Accordingly, for options granted prior to January 1, 2003, compensation expense was not reflected for employee stock options unless they were granted at an exercise price lower than market value on the grant date.

We use the short-cut method to calculate the beginning balance of the APIC pool of the excess tax benefit, and to determine the subsequent impact on the APIC pool and consolidated statements of cash flows of the tax effects of employee stock-based compensation awards that were outstanding upon our adoption of authoritative guidance for the accounting for tax effects of share-based payment awards. Utilizing the short-cut method, we have determined that we have a "Pool of Windfall" tax benefits that can be utilized to offset future shortfalls that may be incurred.

Please read Note 24 Capital Stock for further discussion of our share-based compensation and expense recognized for the years ended December 31, 2011, 2010 and 2009.

Noncontrolling Interests. Net loss applicable to noncontrolling interests on the consolidated income statements included third party investments in PPEA Holding in 2009 when we consolidated PPEA Holding. Please read Note 6 Noncontrolling Interests for further discussion.

Variable Interest Entities. We evaluate our interests in VIEs to determine if we are considered the primary beneficiary and should therefore consolidate the VIE. The primary beneficiary of a VIE is the party that both: (i) has the power to direct the activities of a VIE 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 VIE. Please read Note 16 Variable Interest Entities for further discussion.

Accounting Principles Not Yet Adopted

Fair Value Measurement Disclosures. In May 2011, the FASB issued Accounting Standards Update ("ASU") No. 2011-04 Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU No. 2011-04"). This authoritative guidance changes the wording used to describe the requirements in GAAP for measuring fair value and for disclosing information about fair value measurements. ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The implementation of this guidance will not have a significant impact on our financial condition, results of operations or cash flows.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2 Summary of Significant Accounting Policies (Continued)

Presentation of Comprehensive Income. In June 2011, the FASB issued ASU 2011-05 Comprehensive Income (Topic 220): Presentation of Comprehensive Income ("ASU No. 2011-05"). The FASB's objective in issuing this guidance is to improve the comparability, consistency, and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. ASU No. 2011-05 eliminates the option of presenting components of other comprehensive income as part of the statement of changes in stockholders' equity. The standard requires that all nonowner changes in stockholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We do not expect the implementation of this guidance to have a significant impact on our financial condition, results of operations or cash flows.

Note 3 Chapter 11 Cases

On November 7, 2011, the Debtor Entities commenced the Chapter 11 Cases. Neither Dynegy nor any of its direct or indirect subsidiaries, other than the five Debtor Entities, sought relief under Chapter 11 of the Bankruptcy Code, and none of those entities are debtors under Chapter 11 of the Bankruptcy Code. The Chapter 11 Cases were assigned to the Honorable Cecelia G. Morris, and are being jointly administered for procedural purposes only under the caption *In re: Dynegy Holdings, LLC, et. al.* Case No. 11-38111. The Debtor Entities have remained in possession of their property and continue to operate their businesses as "debtors in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

The normal day-to-day operations of the coal-fired power generation facilities held by DMG and the gas-fired power generation facilities held by DPC have continued without interruption. The commencement of the Chapter 11 Cases did not constitute a default under either of the New Credit Agreements.

In connection with the Chapter 11 Cases, DH, as lender, and the other Debtor Entities, as borrowers, entered into a $15 million intercompany revolving loan agreement, on an unsecured priority basis, that is available to the borrowers to fulfill working capital and other administrative funding needs during the Chapter 11 Cases.

On November 7, 2011, the Debtor Entities filed a motion with the Bankruptcy Court for authorization to reject the leases of the Roseton and Danskammer power generation facilities. On December 20, 2011, the Bankruptcy Court entered a stipulated order approving the rejection of such leases, as amended by a stipulated order entered by the Bankruptcy Court on December 28, 2011, which approved the rejection of such leases subject to, among other things, continued litigation over and determination in the Adversary Proceeding (defined below) of, (a) the effective date of the leases rejection, which is to be no later than December 2, 2011, and (b) the amount of the Lease Indenture Trustee's damages claim arising from the rejection. The Debtor Entities have remained in physical possession of and have continued to operate the leased facilities to the extent necessary to comply with applicable federal and state regulatory requirements until operational control of the facilities is permitted to be transitioned.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3 Chapter 11 Cases (Continued)

Lease Indenture Trustee Contested Matters and Adversary Proceedings. On November 11, 2011, U.S. Bank National Association, in its capacity as Successor Lease Indenture Trustee (the "Lease Indenture Trustee") under the Indentures of Trust, Mortgage, Assignment of Leases and Rents and Security Agreement related to each facility commenced an adversary proceeding against Dynegy Danskammer, L.L.C., Dynegy Roseton, L.L.C and DH (Adversary Proceeding No. 11-09083) (the "Adversary Proceeding") seeking, among other things, a declaration that: (i) the Roseton and Danskammer leases are not leases of real property; (ii) the leases are financings, not leases; and (iii) notwithstanding the lease rejection claims, claims arising from DH's guaranty of certain lease obligations are not subject to a cap pursuant to section 502(b)(6) of the Bankruptcy Code. On January 6, 2012, the Lease Indenture Trustee filed an amended complaint in which it added an additional claim for relief, seeking, among other things, a determination of the allowed amount of the Lease Indenture Trustee's claims against Dynegy Danskammer, L.L.C., Dynegy Roseton, L.L.C., and DH

On January 25, 2012, Dynegy Danskammer, L.L.C., Dynegy Roseton, L.L.C., and DH filed their answer and counterclaims to the amended complaint of the Lease Indenture Trustee asserting, among other things, that the leases are true leases and that such documents are leases of real property subject to section 502(b)(6) of the Bankruptcy Code. Pursuant to a scheduling order entered on January 30, 2012, the Bankruptcy Court has set a deadline of May 8, 2012 for filing summary judgment motions and June 11, 2012 for the commencement of a trial to the extent one is necessary.

On February 21, 2012, the Lease Indenture Trustee filed an answer to the counterclaims filed by Dynegy Danskammer, Dynegy Roseton and DH, and on February 27, 2012, the Lease Indenture Trustee filed a motion for judgment on the pleadings with respect to one issue: whether or not the Lease Indenture Trustee's claims are subject to the damages cap set forth in section 502(b)(6) of the Bankruptcy Code based on the Lease Indenture Trustee's contention that the facility leases concern personal, rather than real, property. The current date to respond to the Lease Indenture Trustee's motion is March 8, 2012, and the Lease Indenture Trustee has noticed a hearing on the motion for March 21, 2012.

On February 29, 2012, Dynegy Danskammer, Dynegy Roseton and DH filed their own motion for judgment on the pleadings, seeking rulings from the Court that: (i) the Lease Indenture Trustee's first claim for relief should be dismissed because the facilities are real property under New York law; (ii) the Lease Indenture Trustee's second claim for relief should be dismissed because the Lease Indenture Trustee cannot invoke the equitable remedy of recharacterization on the grounds that its effort to recharacterize the facility leases as financings is barred by the applicable Lease Indentures, and because recharacterization would be inequitable and contrary to the policies embodied in section 502(b)(6) of the Bankruptcy Code; (iii) the Lease Indenture Trustee's third and fourth claims for relief should be dismissed because section 502(b)(6) of the Bankruptcy Code applies to claims against guarantors of leases such as DH under the lease guarantees, and (iv) the Lease Indenture Trustee's fifth claim for relief should be dismissed to the extent it seeks to recover more than the $550.4 million (plus any allowable pre-petition interest) amount due to the Pass-Through Certificate Holders for whom the Lease Indenture Trustee acts under the Lease Indentures. The current date to respond to the motion for judgment on the pleadings filed by Dynegy Danskammer, Dynegy Roeseton and DH is March 8, 2012, and a hearing has been noticed on the motion for March 21, 2012.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3 Chapter 11 Cases (Continued)

On November 11, 2011, the Lease Indenture Trustee also filed a motion with the Bankruptcy Court seeking the appointment of an examiner. On December 29, 2011, the Bankruptcy Court entered an order directing the appointment of the examiner, which order provides, among other things, that the examiner will investigate (i) the Debtor Entities' conduct in connection with the prepetition 2011 restructuring and reorganization of the Debtor Entities and their non-Debtor affiliates, (ii) any possible fraudulent conveyances, and (iii) whether DH is capable of confirming a Chapter 11 plan.

Pursuant to the order approving the appointment of the examiner, the examiner's investigation is to run for a 60-day period beginning on the date of the appointment (subject to possible extension), at the end of which the examiner must file with the Court and provide to certain parties in interest a written report of his investigation, subject to certain restrictions. An examiner was appointed on January 12, 2012. We anticipate that the examiner will issue a written report describing his findings on or about March 9, 2012.

Restructuring Support Agreements. Prior to the commencement of the Chapter 11 Cases, DH and Dynegy reached an agreement with certain holders of more than $1.4 billion of DH's unsecured senior notes and debentures regarding a potential consensual restructuring (the "Restructuring") of over $4.0 billion of obligations owed by DH. The principal terms of the Restructuring were evidenced by a restructuring support agreement and related term sheet, dated November 7, 2011, which was amended and restated on December 26, 2011 (as amended and restated, the "Noteholder Restructuring Support Agreement"), and entered into by and among Dynegy, DH and the holders of approximately $1.8 billion of DH's unsecured senior notes and debentures and subordinated debentures (the "Consenting Noteholders").

Pursuant to the Noteholder Restructuring Support Agreement, the Consenting Noteholders agreed, among other things, subject to the terms and conditions contained in the Noteholder Restructuring Support Agreement, to (i) vote their claims under DH's unsecured senior notes and debentures and subordinated debentures in favor of the Restructuring and not withdraw or revoke such vote, except as permitted under the Noteholder Restructuring Support Agreement, (ii) not object to the Restructuring; (iii) not initiate legal proceedings inconsistent with or that would prevent, frustrate, or delay the Restructuring; (iv) not solicit, support, formulate, entertain, encourage or engage in discussions or negotiations, or enter into any agreements relating to, any alternative restructuring; and (v) not solicit, encourage, or direct any person or entity, including the indenture trustee under the indenture for the Senior Notes or the indenture for the Subordinated Notes, to undertake any such action. Additionally, the Consenting Noteholders agreed not to transfer or assign their claims, except to parties who also agree to be bound by the Noteholder Restructuring Support Agreement, subject to certain exceptions. Subject to fiduciary duties, Dynegy and DH agree to use their reasonable best efforts to (i) support and complete the Restructuring, (ii) take all necessary and appropriate actions in furtherance of the Restructuring and the transactions related thereto, (iii) complete the Restructuring and all transactions related thereto within the time-frames outlined in the Noteholder Restructuring Support Agreement, (iv) obtain all required governmental, regulatory and/or third-party approvals for the Restructuring and (v) take no actions inconsistent with the Noteholder Restructuring Support Agreement or the confirmation and consummation of the Plan (as defined below).

The Noteholder Restructuring Support Agreement provides that it may be terminated by DH, Dynegy, or a majority of the Consenting Noteholders if (among other things): (i) the Bankruptcy Court has not entered an order approving the disclosure statement related to the Plan (as defined below) by March 15, 2012; (ii) the Bankruptcy Court has not entered an order confirming the Plan by June 15,

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3 Chapter 11 Cases (Continued)

2012; or (iii) the Plan has not become effective by August 1, 2012. Further, certain noteholders may terminate their obligations in their individual capacity if: (i) any examiner finds that any member of DH's board of directors was more likely than not to have committed acts of fraud, willful misconduct, breach of fiduciary duty or any other act which would likely make them unable to satisfy certain standards set out in the Bankruptcy Code; (ii) any modification is made to any Plan Related Document (as defined in the Noteholder Restructuring Support Agreement) that is inconsistent in any material respect with the Plan Related Documents approved by each of the Noteholders as of December 26, 2011; or (iii) the Bankruptcy court has not entered an order approving the Disclosure Statement by March 15, 2012.

In addition, on December 13, 2011, we entered into a binding term sheet with Resources Capital Management Corporation and certain of its affiliates and subsidiaries ("PSEG"), to settle and resolve all issues in lieu of further litigation, regarding, among other things, the Roseton and Danskammer leases and all of the parties' rights and claims arising under the related lease documents, including certain tax indemnity agreements, pursuant to which settlement, PSEG agreed to support the confirmation of the Debtor Entities' plan of reorganization, bringing the aggregate amount of claims agreeing to support the plan up to approximately $1.9 billion.

Plan of Reorganization. On December 1, 2011, Dynegy and DH, as co-plan proponents, filed a proposed Chapter 11 plan of reorganization and a related disclosure statement for DH with the Bankruptcy Court. On January 19, 2012, they filed a proposed amended plan and related disclosure statement and recently filed a second amended plan (the "Plan") and related disclosure statement (the "Disclosure Statement") with the Bankruptcy Court. The Plan addresses claims against and interests in DH only and does not address claims against and interests in the other Debtor Entities.

The proposed Plan sets forth the material terms of the Restructuring pursuant to which unsecured claims of DH, including its outstanding Senior Notes, will be cancelled and exchanged for a combination of (i) $1.015 billion aggregate principal amount of our new secured notes ("New Secured Notes") (or a cash payment in lieu thereof), (ii) $2.1 billion of mandatorily convertible preferred stock of Dynegy (the "Preferred Stock") and (iii) $400 million cash (plus an amount equal to all interest that would have accrued on the New Secured Notes from the filing date of the Chapter 11 Cases). Our existing Dynegy common stock will remain outstanding. Further, pursuant to the proposed Plan, it is a condition to the effective date of such plan (the "Effective Date") that the rejection damages arising from the rejection of the leases of the Roseton and Danskammer power generation facilities are determined in an amount not to exceed $300 million (or $190 million net of the claim of PSEG, which has already been allowed by the Bankruptcy Court in the amount of $110 million), subject only to a potential waiver.

The New Secured Notes will pay cash interest at an 11 percent annual rate and have a seven year maturity. The New Secured Notes will have customary negative covenants restricting asset transfers, mergers, dividends, incurrence of debt and liens, restricted payments, sale and leaseback transactions, dividend and other payment restrictions and change of control (in each case, with certain agreed upon exceptions). The New Secured Notes will be secured by a first priority security interest in (subject to certain exceptions and permitted liens): (i) the assets of certain of our direct and indirect wholly-owned subsidiaries (including a first priority security interest in and lien on a $55 million debt service account) and (ii) the equity interests in certain of our direct and indirect subsidiaries.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3 Chapter 11 Cases (Continued)

The aggregate principal amount of New Secured Notes and the cash component of the Restructuring payments are subject to certain adjustments as more fully set forth in the Plan. For example, the principal amount of New Secured Notes to be issued will be reduced (and the cash component increased) by specified amounts of excess cash at DH and its subsidiaries (other than the bankruptcy-remote entities that own Dynegy's coal and natural gas fired power generation businesses) and may also be increased or decreased based on the amount of the aggregate claims arising from the rejection of the Roseton and Danskammer leases. Additionally, Dynegy may, in lieu of issuing any New Secured Notes, provide for a cash payment equal to the aggregate principal amount of New Secured Notes; provided that such cash payment is funded by debt on terms that, taken as a whole (and subject to certain exceptions), are no less favorable to Dynegy than the terms of the New Secured Notes.

The Preferred Stock will be Redeemable Convertible Preferred Shares, par value $0.01 per share, issued by Dynegy and will accrue dividends, commencing on November 7, 2011, at an annual rate of 4 percent through December 31, 2013, 8 percent from January 1, 2014 through December 31, 2014, and 12 percent thereafter, compounding quarterly as set forth in the Designation of the Preferred Stock attached to the Plan (the "Stock Designation"). Dividends will not be paid in cash, but will accrue. The Preferred Stock will not be convertible at the option of the holder; but will automatically convert on December 31, 2015 or upon the occurrence of a Dynegy bankruptcy event. Based upon the capital structure of Dynegy anticipated to be in effect as of the Plan Effective Date, the Preferred Stock would be convertible into 97 percent of Dynegy's fully-diluted common stock (other than equity issued as compensation) on the terms set forth in the Stock Designation. The Preferred Stock may be redeemed by Dynegy in whole or in part, subject to certain limitations, as set forth in the Stock Designation, at an aggregate price (assuming redemption of all Preferred Stock outstanding as of the Effective Date) equal to: (i) $1.95 billion if redeemed prior to May 8, 2013; (ii) $2.0 billion if redeemed on or after May 8, 2013 through December 31, 2013; and (iii) $2.1 billion if redeemed on or after January 1, 2014 through the mandatory conversion date, in each case, plus accrued and unpaid dividends; provided, that if Dynegy redeems less than all of the shares of Preferred Stock, the amounts set forth in clauses (i) and (ii) will be replaced with $2.1 billion. Dynegy may only redeem less than all of the shares of Preferred Stock with the proceeds of a firm commitment, underwritten issuance of certain permitted stock that is entered into prior to December 31, 2014. The approval of holders of Preferred Stock will be required for certain actions by Dynegy including: making certain changes to the fundamental rights of the Preferred Stock; making certain changes to Dynegy's certificate of incorporation or bylaws that are adverse to the Preferred Stock; incurring certain indebtedness disposing of certain assets; making certain investments; and engaging in certain merger or acquisition transactions. Dynegy and its Subsidiaries are restricted from entering into certain affiliate transactions subject to obtaining certain approval, and, for certain affiliate transactions, obtaining a fairness opinion. Dynegy may, without the consent of the holders of shares of Preferred Stock, issue and sell shares of certain permitted stock, subject to certain restrictions set forth in the Stock Designation and to the right of first offer of the holders of shares of Preferred Stock.

Pursuant to the proposed Plan, the holders of DH's Subordinated Notes would be entitled to participate in the Restructuring as unsecured note holders, but their recovery would be subject to enforcement of their contractual subordination to the Senior Notes. Alternatively, the subordinated note holders will be offered the opportunity to participate, without subordination, in the restructuring as unsecured note holders at $0.35 for every dollar of claims.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3 Chapter 11 Cases (Continued)

Accounting Impact. In conjunction with the commencement of the Chapter 11 Cases, we evaluated whether we should continue to consolidate DH and its wholly-owned subsidiaries, including the other Debtor Entities as well as the DH subsidiaries included in our Gas segment. We concluded that, as a result of the commencement of the Chapter 11 Cases, under applicable accounting standards, we no longer have a controlling financial interest in DH and its wholly-owned subsidiaries, and therefore, DH and its consolidated subsidiaries should no longer be consolidated in our consolidated financial statements as of November 7, 2011.

In performing this analysis, we concluded that the activities that most significantly impact DH's economic performance are (i) the financing and restructuring of the pre-petition obligations of the Debtor Entities and (ii) the management of the natural gas-fired generation facilities that are operated by DH's non-debtor subsidiaries. The activities associated with the financing and restructuring of DH's pre-petition obligations are ultimately subject to confirmation of the Plan by the Bankruptcy Court. Furthermore, while we continue to manage the ordinary course operations of the natural-gas fired generation facilities included in the Gas segment, to the extent any ordinary course activities could have a significant impact on the operations of the Gas segment, the Bankruptcy Court would generally have to approve such activities. Additionally, significant decisions regarding the natural gas-fired generation business that are outside the normal course of business would also be subject to the approval of the Bankruptcy Court.

Therefore, despite our continued 100 percent ownership of DH, we concluded, under the applicable accounting guidance, that as a result of the bankruptcy we do not have the ability to make decisions that most significantly impact the economic performance of DH. As such, based on the applicable accounting guidance, we no longer have a controlling financial interest in DH as of November 7, 2011. Accordingly, we have deconsolidated DH and its consolidated subsidiaries from our consolidated financial statements as of the date of the filing of the Chapter 11 Cases.

In order to deconsolidate DH and its consolidated subsidiaries, the carrying values of the assets and liabilities of DH and its consolidated subsidiaries were removed from our consolidated balance sheets as of November 7, 2011. Accordingly, we recorded our investment in DH at its estimated fair value of zero as of November 7, 2011. 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 relevant to our investment at that time. Our assessment of fair value considered estimates of the value of DH's equity in the Gas segment and DH's rights related to the Undertaking Agreement, as well as estimates of the fair value of DH's debt and lease obligations. Additionally, our analysis considered the inherent uncertainty in value resulting from the Chapter 11 Cases. Such valuation was determined as of November 7, 2011 and should not be relied on for a determination of value at any other period in time given, among other things, significant variability in commodity prices underlying the valuation analysis.

Consistent with historical practice, our estimate of the fair value of DH's equity in the Gas segment was determined using the income approach based on an unlevered discounted cash flows methodology. This methodology estimates the value of an asset or business by calculating the present value of expected future cash flows using a market participant's expected weighted average cost of capital (discount rate). The Gas segment's estimated future operating results were based on discrete financial forecasts developed by management for planning purposes. To complete the fair value of DH's equity in the Gas segment, we then subtracted the net debt (debt less cash on hand) of the Gas

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3 Chapter 11 Cases (Continued)

segment from the value of the business determined using the unlevered discounted cash flows methodology. The results of our fair value assessment using the income approach were corroborated using market information about recent sales transactions.

Our estimate of the fair value of DH's interest in the Undertaking Agreement, which is supported by the future cash flows that Dynegy receives from its Coal segment, was determined using the income approach, using estimates of the underlying assets' cash flows based on a weighting of unlevered and levered discounted cash flows methodologies. The unlevered discounted cash flows methodology was applied using similar procedures as described above to value DH's equity in the Gas segment. In the levered discounted cash flows methodology, again, the future operating results were based on discrete financial forecasts developed by management for planning purposes but with the inclusion of the Coal segment term loan interest and principal payments. This methodology estimates the fair value of the future cash flows from the Coal segment by calculating the present value of expected future cash flows using a discount rate that reflects a market participant's expected equity discount rate.

We have estimated the fair value of the allowed claims at DH arising from the lease rejection to be $300 million (or $190 million net of the claim of PSEG which has already been allowed by the Bankruptcy Court in the amount of $110 million). Our estimate of the fair value of the obligations arising from the rejection of the Roseton and Danskammer leases considered various scenarios and projected outcomes including, among other things, our view that the Lease Indenture Trustee's allowed claim should be capped pursuant to Section 502(b)(6) of the Bankruptcy Code which governs claims arising from the rejection of leases of nonresidential real property. As discussed above, the Lease Indenture Trustee is seeking allowance of the lease claims in the amount of approximately $900 million, however we believe that such lease claims (exclusive of PSEG's $110 million allowed claim) are in fact significantly lower given the application of any one or more of the following factors, among others: (i) the claims are, as stated, subject to the cap established in section 502(b)(6) of the Code, (ii) the Lease Indenture Trustee cannot recover in excess of approximately $550 million, including any recoveries they may receive as a result of their primary claims against the two lessee entities, (iii) the Lease Indenture Trustee has significant other sources of recovery on its lease rejection damages claim and (iv) certain aspects of its claim have already been resolved by the Court and released by the relevant counterparties. The Plan Proponents have estimated the lease claims (exclusive of the TIA Claim) at $190 million to reflect our belief that the aggregate amount of such allowed claims (including PSEG's $110 million allowed claim) will not exceed $300 million, which is the maximum amount in which such claims may be allowed for the Plan to become effective (subject only to the potential waiver of such condition precedent to consummation of the Plan by the Plan Proponents to allow such claims in an amount up to $400 million (or $290 million net of PSEG's $110 million allowed claim) or the Plan Proponents and the Consenting Noteholders, collectively, to allow such claims in an amount in excess of $400 million (or $290 million net of PSEG's $110 million allowed claim). However, as indicated herein, the allowed amounts of the lease claims are the subject of litigation, the outcome of which is inherently uncertain, and therefore may be significantly higher or lower.

After considering the estimated fair values of the Gas segment's future cash flows and related debt, the fair value of the Undertaking Agreement and the estimated fair value of the rejection damage claims, we considered whether there was sufficient value to repay DH's outstanding unsecured debt obligations. It was determined that there was not sufficient value to repay DH's unsecured debt obligations, therefore, we believe that it is a reasonable assumption that a third party market participant would not assign any residual value to the equity of DH, particularly considering the

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3 Chapter 11 Cases (Continued)

inherent uncertainty in value resulting from the Chapter 11 Cases, inclusive of the rejection damage claims litigation. Accordingly, we have reflected our investment in DH at its estimated fair value of zero as of November 7, 2011 and recorded a loss of $1,657 million, which reflects the difference between (i) the estimated fair value of our retained 100 percent noncontrolling investment in DH at the date of deconsolidation, and (ii) the carrying amount of DH's consolidated assets and liabilities. The loss is included in Loss on deconsolidation in our consolidated statements of operations.

Subsequent to the deconsolidation of DH, we are accounting for our investment in DH using the equity method of accounting because we continue to exercise significant influence over the operations of DH. Please read Note 15 Unconsolidated Investments and Note 16 Variable Interest Entities for further discussion. Our management team continues to make the ongoing day-to-day operating decisions related to DH, including the operations of its Gas segment and there are various service agreements between us and various DH subsidiaries. Furthermore, the Plan has been proposed jointly by Dynegy and DH and the same management team will be soliciting acceptance of the Plan. Based on these facts, we believe we exert significant influence over DH and the equity method of accounting is appropriate.

Note 4 Merger Agreements

On August 13, 2010, we entered into a merger agreement with an affiliate of The Blackstone Group L.P. (as amended, the "Blackstone Merger Agreement"), pursuant to which we would be acquired and our stockholders would receive $4.50 per share in cash. On November 16, 2010, the agreement was amended to increase the merger consideration to $5.00 per share in cash. The Blackstone Merger Agreement was not approved by our stockholders at the special stockholders' meeting on November 23, 2010 and was subsequently terminated by the parties in accordance with the terms of the agreement. The Blackstone Merger Agreement requires us to pay Blackstone a termination fee in the amount of $16 million in the event that within 18 months of November 23, 2010, we consummate an alternative transaction having an aggregate value of more than $4.50 per share.

On November 23, 2010, we commenced the solicitation of transaction proposals from a broad group of potentially interested parties, including Icahn Enterprises L.P. ("Icahn") and other potential strategic and financial buyers. As a result of those efforts, on December 15, 2010, our Board of Directors unanimously approved a merger agreement between us and an affiliate of Icahn (as amended, the "Icahn Merger Agreement"). In connection with the Icahn Merger Agreement, Icahn launched a cash tender offer on December 22, 2010 for all of the issued and outstanding shares of our common stock at $5.50 per share (the "Tender Offer"). On January 25, 2011, we announced that we had not received any other bona fide acquisition proposals. At the expiration of the Tender Offer on February 18, 2011, an insufficient number of shares had been tendered in response to the Tender Offer, and as a result the Icahn Merger Agreement automatically terminated. In connection with the termination, and as required by the Icahn Merger Agreement, we paid $5 million to Icahn with respect to expenses incurred by Icahn related to the Icahn Merger Agreement. Further, we may be required to pay additional fees of $11 million in the event that within 18 months of February 18, 2011, we consummate an alternative transaction having an aggregate value of more than $5.50 per share.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5 Dispositions, Contract Terminations and Discontinued Operations

Dispositions and Contract Terminations

LS Power Transactions. On November 30, 2009, we sold certain assets and investments to LS Power. We consummated the sale with LS Power in two parts (the "LS Power Transactions"), with the issuance of notes by DH, on December 1, 2009, and the remainder of the transactions closing on November 30, 2009. At closing, we received $936 million in cash, net of closing costs. Of the proceeds, $547 million related to the disposition of assets, including our interest in the Sandy Creek project. We also received $175 million from the release of restricted cash on our consolidated balance sheets that was used to support our funding commitment to the Sandy Creek Project and $214 million for the issuance of $235 million notes payable at the close of the transaction. In addition, we received 245 million shares of our Class B common stock from LS Power. In exchange, we sold to LS Power five peaking and three combined-cycle generation assets, as well as our remaining interest in the Sandy Creek Project, and DH issued the notes to an affiliate of LS Power. Please read Note 20 Related Party Transactions Transactions with LS Power for further discussion.

The remaining 95 million shares of our Class B common stock held by LS Power were converted into the same number of shares of our Class A common stock.

In connection with the LS Power Transactions, Dynegy and LS Power entered into a new shareholder agreement (the "New Shareholder Agreement"), which, among other things, generally restricts LS Power from increasing its ownership for up to 30 months. Dynegy and LS Power have also terminated the original shareholder agreement, dated September 14, 2006, which provided LS Power with special approval rights, board representation and certain other rights associated with its former Class B shares. The New Shareholder Agreement expires in accordance with its terms in June 2012.

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

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

We recorded pre-tax impairment charges of $326 million, inclusive of costs to sell, related to the assets included in the LS Power Transactions that did not meet the criteria for classification as discontinued operations for the year ended December 31, 2009. The charges are included in Impairment and other charges in our consolidated statements of operations. Please read Note 8 Impairment and Restructuring Charges for further discussion of these impairments.

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

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Note 5 Dispositions, Contract Terminations and Discontinued Operations (Continued)

PPEA Holding Company LLC. On November 10, 2010, we completed the sale of our interest in PPEA Holding to one of the other investors in PPEA Holding. We recognized a loss of approximately $28 million on the sale, which is included in Losses from unconsolidated investments in our consolidated statements of operations. This loss represents $28 million of losses reclassified from Accumulated other comprehensive loss. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion.

Discontinued Operations

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

The Arizona power generation facilities, as well as our Bluegrass facility, met the criteria of held for sale during the third quarter 2009. At that time, we discontinued depreciation and amortization of the Arizona power generation facilities' and Bluegrass' property, plant and equipment. Depreciation and amortization expense related to the Arizona power generation facilities totaled approximately $14 million for the year ended December 31, 2009. Depreciation and amortization expense related to the Bluegrass facility totaled approximately $1 million for the year ended December 31, 2009. We recorded an impairment charge of $235 million related to the Arizona power generation facilities during the third quarter 2009. We previously recorded impairment charges of $5 million and $18 million related to the Bluegrass facility during the first and second quarters of 2009, respectively. Please read Note 8 Impairment and Restructuring Charges for further discussion of these impairments. The results of Bluegrass' and the Arizona power generation facilities' operations are reported in discontinued operations for all periods presented in our Gas segment.

Heard County. On April 30, 2009, we completed the sale of our interest in the Heard County power generation facility for approximately $105 million. Heard County was classified as held for sale during the first quarter 2009. At that time, we discontinued depreciation and amortization of Heard County's property, plant and equipment. Depreciation and amortization expense related to Heard County totaled approximately less than $1 million for the year ended December 31, 2009. The results of Heard County's operations are included in discontinued operations for all periods presented in our Gas segment.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5 Dispositions, Contract Terminations and Discontinued Operations (Continued)

Summary. The following table summarizes information related to our discontinued operations:

	Total (in millions)	
2010		
Revenues	$	
Income from operations before taxes		1
Income from operations after taxes		1
2009		
Revenues	$	116
Loss from operations before taxes (1)		(249)
Loss from operations after taxes		(165)
Loss on sale before taxes		(94)
Loss on sale after taxes		(57)

(1) Includes $23 million and $235 million of impairment charges related to our Bluegrass power generation facility and our Arizona power generation facilities, respectively, which are included in the Gas segment.

Note 6 Noncontrolling Interests

We account for noncontrolling interests in accordance with FASB ASC 810, Consolidation, 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 income (loss) attributable to our stockholders:

	Twelve Months Ended December 31, 2009 (in millions)	
Loss from continuing operations	$	(1,025)
Loss from discontinued operations, net of tax benefit of $121		(222)
Net loss	$	(1,247)

As a result of the deconsolidation and subsequent sale of our interest in PPEA Holding, effective January 1, 2010, there are no longer any noncontrolling interests in any of our consolidated subsidiaries, and as a result, no reconciliation is needed for the twelve months ended December 31, 2010 and 2011.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 6 Noncontrolling Interests (Continued)

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

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

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7 Investments

The amortized cost basis, unrealized gains and losses and fair values of investments in available for sale investments as of December 31, 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	$ 45	$	$	$ 45
Certificates of Deposit	20			20
Corporate Securities	6			6
U.S. Treasury and Government Securities (1)	120			120
Total Dynegy	$ 191	$	$	$ 191

(1) Includes $85 million in Broker margin account on our consolidated balance sheets in support of transactions with our futures clearing manager.

During the twelve months ended December 31, 2011 and 2010, we received proceeds of $475 million and $317 million, respectively, 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 twelve months ended December 31, 2011 and 2010.

We did not have any investments as of December 31, 2011.

Note 8 Impairment and Restructuring Charges

2010 Impairment Charges

Casco Bay Impairment. In August 2010, in connection with the Blackstone Merger Agreement, we determined it was more likely than not that our Moss Landing, Morro Bay, Oakland and Casco Bay facilities would be disposed of before the end of their previously estimated useful lives, as Blackstone had entered into a separate agreement to sell these facilities to a third party upon the closing of the Blackstone Merger Agreement. Based on the terms of the Blackstone Merger Agreement and our impairment analysis of the impact of such agreement on the recoverability of the carrying value of our long-lived assets, we recorded a pre-tax impairment charge of $134 million ($81 million after-tax) during the three months ended September 30, 2010 to reduce the carrying value of our Casco Bay facility and related assets to its fair value. This charge is included in Impairment and other charges in our consolidated statements of operations in the Gas segment.

In performing the impairment analysis, we concluded that the assets Blackstone planned to sell to a third party did not meet the criteria of "held for sale," as the agreement to sell these assets was a contractual arrangement between Blackstone and the third party. Dynegy management had not committed to any plan to dispose of these assets prior to the end of their previously estimated useful lives. As such, we assessed the recoverability of the carrying value of these certain assets using expected cash flows from the proceeds from the potential sale of these assets, probability weighted with the expected cash flow from continuing to hold and use the assets. We performed this analysis considering a range of likelihoods that management considered reasonable regarding whether the sale of these assets would be completed. In any of the scenarios within this range of the probabilities we considered

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8 Impairment and Restructuring Charges (Continued)

reasonable, the expected undiscounted cash flows from the Moss Landing, Morro Bay and Oakland facilities were sufficient to recover their carrying values, while the expected undiscounted cash flows from the Casco Bay facility were not. Therefore, we recorded an impairment charge to reduce the carrying value of the Casco Bay facility and related assets to its estimated fair value. We determined the fair value of the facility based on assumptions that reflect our best estimate of third party market participants' considerations, and corroborated these assumptions based upon the terms of the proposed sale of the facilities. The Blackstone Merger Agreement ultimately did not receive stockholder approval, and at December 31, 2010, we no longer considered it more likely than not that these facilities will be disposed of before the end of their currently estimated useful lives.

Other. In the first quarter of 2010, as a result of uncertainty and risk surrounding PPEA's financing structure, we recorded a pre-tax impairment charge of approximately $37 million to reduce the carrying value of our investment in PPEA Holding to zero. In the fourth quarter 2010, we sold our interest in this investment. Please read Note 15 Unconsolidated Investments for additional information.

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

2009 Impairment Charges

The following summarizes pre-tax impairment charges recorded during 2009 and the line item in which they appear in our consolidated statements of operations:

	Impairment and other charges	Income (loss) from discontinued operations	Total
	(in millions)		
Bluegrass	$	$ (5)	$ (5)
Assets included in the LS Power Transactions	(326)	(253)	(579)
Roseton and Danskammer	(212)		(212)
Total impairment charges	$ (538)	$ (258)	$ (796)

Bluegrass. During the first quarter 2009, we performed a goodwill impairment test due to changes in market conditions that would more likely than not reduce the fair values of our reporting units below their carrying amounts. Please read Note 17 Goodwill for further discussion. This decline in value also triggered testing of the recoverability of our long-lived assets. We performed an impairment analysis and recorded a pre-tax impairment charge of $5 million ($3 million after tax). This charge, which related to the Bluegrass power generation facility, is included in Income (loss) on discontinued operations in our consolidated statements of operations. We determined the fair value of the Bluegrass

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8 Impairment and Restructuring Charges (Continued)

facility using assumptions that reflected our best estimate of third party market participants' considerations.

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

In performing the June 30, 2009 impairment analysis, we used an 80 percent likelihood at June 30, 2009 of reaching an agreement for sale of the assets, and certain assumptions about the terms of such a sale. Upon reaching the agreement with LS Power, the assets qualified as held for sale, and additional impairment charges were recorded, as discussed below.

On August 9, 2009, we entered into the purchase and sale agreement with LS Power. At that time, the operating assets included in that agreement met the criteria of held for sale. Accordingly, we updated our impairment analysis reflecting the estimated fair value for the consideration to be received from LS Power inclusive of costs to sell. As a result, we recognized pre-tax impairment charges of $382 million for the three month period ended September 30, 2009. The $147 million charge is included in Impairment and other charges in our consolidated statements of operations. The $235 million charge is included in Income (loss) on discontinued operations in our consolidated statements of operations.

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

Please refer to Note 5 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further discussion.

Roseton and Danskammer. In updating our impairment analysis for assets that were being considered for sale as discussed above, we noted that the aggregate carrying value of the assets included in the proposed transaction exceeded the aggregate fair value of the consideration to be

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8 Impairment and Restructuring Charges (Continued)

received. In addition, we noted a continued weakening in forward capacity and forward power prices in certain of the markets in which we operate. This indicated a possible decline in the value of power generation assets in all three of our reportable segments. Therefore, at June 30, 2009, we updated our March 31, 2009 impairment analysis for our remaining power generation facilities not currently under consideration for sale. As a result of changes in market conditions in the second quarter 2009 within the Northeast region of the United States, we recorded a pre-tax impairment charge of $208 million ($129 million after-tax) related to the Roseton and Danskammer power generation facilities. This charge is included in Impairment and other charges in our consolidated statements of operations. We determined the fair value of these facilities using assumptions that reflect our best estimate of third party market participants' considerations. This involved using the present value technique, incorporating our best estimate of third party market participants' assumptions about the best use of assets, future power and fuel costs and the costs of complying with environmental regulations. Based on a continuation of expected cash flow losses for these assets in 2009, we recorded additional pre-tax impairment charges of $4 million ($3 million after-tax) in 2009.

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

Restructuring Charges

In the fourth quarter 2010, we established a plan to align our corporate cost structure with the current challenging commodity price environment. As a result of this plan, we eliminated approximately 135 positions, and we paid approximately $8 million of severance benefits to affected employees in 2011. We eliminated an additional 40 positions in connection with the closure of our Vermilion facility in 2011, and paid $1 million of severance benefits in connection with the facility's closure. We recognized pre-tax charges of $12 million in 2010 in connection with these restructuring activities and with the closure of our South Bay facility. These charges are included in Impairment and other charges in our consolidated statements of operations and were based on contractual obligations under our existing benefit plans.

During 2011, we continued to align our corporate structure and recognized pre-tax charges of approximately $4 million in connection with the additional restructuring activities. Approximately 45 positions were eliminated and we expect to pay out in 2012 approximately $1 million of severance benefits to affected employees.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8 Impairment and Restructuring Charges (Continued)

The following table summarizes activity related to liabilities associated with costs related to severance and retention benefits:

	Year Ended December 31,		
	2011	2010	2009 (1)
	(in millions)		
Beginning of year	$ 15	$ 12	$ 2
Expense (2)	6	12	11
Payments	(18)	(9)	(1)
Deconsolidation of DH (3)	(2)		
End of year	$ 1	$ 15	$ 12

(1) Amounts primarily relate to severance and retention benefits associated with employees at the Plum Point and South Bay facilities.

(2) 2011 expense includes $2 million in retention benefits.

(3) DH was deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

Note 9 Risk Management Activities, Derivatives and Financial Instruments

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

Our commodity risk management strategy gives us the flexibility to sell energy and capacity through a combination of spot market sales and near-term contractual arrangements (generally over a rolling 1 to 3 year time frame). Our commodity risk management goal is to protect cash flow in the near-term while keeping the ability to capture value longer-term. Increasing collateral requirements and our liquidity position could impact our ability to effectively employ our risk management strategy.

Many of our contractual arrangements are derivative instruments and must be accounted for at fair value. We also manage commodity price risk by entering into capacity forward sales arrangements, tolling arrangements, RMR contracts, fixed price coal purchases and other arrangements that do not receive fair value accounting treatment because these arrangements do not meet the definition of a derivative or are designated as "normal purchase normal sales." As a result, the gains and losses with respect to these arrangements are not reflected in the consolidated statements of operations until the settlement dates.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9 Risk Management Activities, Derivatives and Financial Instruments (Continued)

Quantitative Disclosures Related to Financial Instruments and Derivatives

The following disclosures and tables present information concerning the impact of derivative instruments on our consolidated balance sheets and statements of operations. In the table below, commodity contracts primarily consist of derivative contracts related to our power generation business that we have not designated as accounting hedges, that are entered into for purposes of economically hedging future fuel requirements and sales commitments and securing commodity prices. Interest rate contracts primarily consist of derivative contracts related to managing our interest rate risk. As of December 31, 2011, our commodity derivatives were comprised of both long and short positions; a long position is a contract to purchase a commodity, while a short position is a contract to sell a commodity. As of December 31, 2011, we had net long/(short) commodity derivative contracts outstanding and notional interest rate swaps outstanding in the following quantities:

Contract Type	Hedge Designation	Quantity (in millions)	Unit of Measure	Net Fair Value (in millions)
Commodity derivative contracts:				
Electric energy (1)	Not designated	(18)	MW	$ 2
Electric energy, affiliates	Not designated	(2)	MW	$ 5
Interest rate contracts:				
Interest rate swaps	Not designated	312	Dollars	$ (3)
Interest rate caps	Not designated	500	Dollars	$ 1

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

Derivatives on the Balance Sheet. The following table presents the fair value and balance sheet classification of derivatives in the consolidated balance sheets as of December 31, 2011 and 2010,

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9 Risk Management Activities, Derivatives and Financial Instruments (Continued)

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	December 31, 2011	December 31, 2010
		(in millions)	
Derivatives designated as hedging instruments:			
Derivative Assets:			
Interest rate contracts	Assets from risk management activities	$	$ 1
Derivative Liabilities:			
Interest rate contracts	Liabilities from risk management activities		
Total derivatives designated as hedging instruments, net			1
Derivatives not designated as hedging instruments:			
Derivative Assets:			
Commodity contracts	Assets from risk management activities	65	1,265
Commodity contracts, affiliates	Assets from risk management activities, affiliates	7	
Interest rate contracts	Assets from risk management activities	1	5
Derivative Liabilities:			
Commodity contracts	Liabilities from risk management activities	(63)	(1,231)
Commodity contracts, affiliates	Liabilities from risk management activities, affiliates	(2)	
Interest rate contracts	Liabilities from risk management activities	(3)	(6)
Total derivatives not designated as hedging instruments, net		5	33
Total derivatives, net		$ 5	$ 34

Impact of Derivatives on the Consolidated Statements of Operations

The following discussion and table presents the location and amount of gains and losses on derivative instruments in our consolidated statements of operations segregated between designated, qualifying hedging instruments and those that are not, by type of contract.

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

Our former investee, PPEA, which we consolidated through December 31, 2009, had certain interest rate swap agreements which were designated as cash flow hedges. Therefore, the effective portion of the changes in value prior to July 28, 2009 was reflected in other comprehensive income (loss). On July 28, 2009, we determined the interest rate swap agreements no longer qualified for cash flow hedge accounting because the hedged forecasted transaction (that is, the future interest payments arising from the PPEA Credit Agreement Facility) was no longer probable of occurring. We performed a final effectiveness test as of July 28, 2009 and no ineffectiveness was recorded. Effective January 1, 2010, we deconsolidated our investment in PPEA Holding, and we sold our interest in this entity in the fourth quarter of 2010. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion of our association with PPEA. The amounts previously deferred in Accumulated other comprehensive income (loss) were recognized in earnings upon our sale of our investment in PPEA Holding in the fourth quarter of 2010, resulting in a loss of $28 million, included in Losses from unconsolidated investments on our consolidated statement of operations.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9 Risk Management Activities, Derivatives and Financial Instruments (Continued)

During the twelve month periods ended December 31, 2011, 2010 and 2009, there was no ineffectiveness from changes in fair value of derivative positions and no amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows in any of the periods. No amounts were reclassified to earnings in connection with forecasted transactions that were considered probable of not occurring.

We recognized a gain of $166 million in Other comprehensive loss on the effective portion of interest rate swap contracts designated as cash flow hedges for the year ended December 31, 2009. 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 income since that date.

Fair Value Hedges. We also enter into derivative instruments that qualify, and that we may elect to designate, as fair value hedges. We previously used interest rate swaps to convert a portion of our non-prepayable fixed-rate debt into floating-rate debt. These derivatives and the corresponding hedged debt matured April 1, 2011. During the twelve month periods ended December 31, 2011, 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. In addition, there were no gains or losses related to the recognition of firm commitments that no longer qualified as fair value hedges.

The impact of interest rate swap contracts designated as fair value hedges and the related hedged item on our consolidated statements of operations for the twelve months ended December 31, 2011, 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 consolidated statements of operations (herein referred to as "mark-to-market accounting treatment"). As a result, these mark-to-market gains and losses are not reflected in the consolidated statements of operations in the same period as the underlying activity for which the derivative instruments serve as economic hedges.

For the twelve months ended December 31, 2011, our revenues included approximately $162 million of mark-to-market losses related to commodity derivative activity compared to approximately $21 million of mark-to-market gains and approximately $180 million of mark-to-market losses in the periods ended December 31, 2010 and 2009, respectively.

The impact of derivative financial instruments that have not been designated as hedges on our consolidated statements of operations for the twelve month periods ended December 31, 2011, 2010 and 2009 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions or interest payments associated with these financial

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9 Risk Management Activities, Derivatives and Financial Instruments (Continued)

instruments. Therefore, this presentation is not indicative of the economic results we expect to realize when the underlying physical transactions settle and interest payments are made.

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of All Gain (Loss) Recognized in Income on Derivatives for the Twelve Months Ended December 31, 2011	2010	2009
		(in millions)		
Commodity contracts	Revenues	$ (124)	$ 185	$ 337
Commodity contract with affiliates	Revenues	(19)		
Interest rate contracts	Interest expense	(3)		(12)

Note 10 Fair Value Measurements

The following tables set forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value as of December 31, 2011 Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$	$ 64	$ 1	$ 65
Electricity derivatives, affiliates		2	5	7
Natural gas derivatives				
Other derivatives				
Total assets from commodity risk management activities	$	$ 66	$ 6	$ 72
Assets from interest rate swaps			1	1
Total	$	$ 66	$ 7	$ 73
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$	$ (62)	$ (1)	$ (63)
Electricity derivatives, affiliates		(1)	(1)	(2)
Natural gas derivatives				
Heat rate derivatives				
Other derivatives				
Total liabilities from commodity risk management activities	$	$ (63)	$ (2)	$ (65)
Liabilities from interest rate swaps			(3)	(3)
Total	$	$ (63)	$ (5)	$ (68)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Fair Value Measurements (Continued)

	Fair Value as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$	$ 526	$ 77	$ 603
Natural gas derivatives		613	5	618
Other derivatives		44		44
Total assets from commodity risk management activities	$	$ 1,183	$ 82	$ 1,265
Assets from interest rate swaps		6		6
Short-term investments:				
Commercial paper		45		45
Certificates of deposit		20		20
Corporate securities		6		6
U.S. Treasury and government securities (1)		120		120
Total short-term investments	$	$ 191	$	$ 191
Total	$	$ 1,380	$ 82	$ 1,462
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$	$ (311)	$ (28)	$ (339)
Natural gas derivatives		(825)		(825)
Heat rate derivatives			(31)	(31)
Other derivatives		(36)		(36)
Total liabilities from commodity risk management activities	$	$ (1,172)	$ (59)	$ (1,231)
Liabilities from interest rate swaps		(6)		(6)
Total	$	$ (1,178)	$ (59)	$ (1,237)

(1) Includes $85 million in Broker margin account on our consolidated balance sheets in support of transactions with our futures clearing manager.

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

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Fair Value Measurements (Continued)

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.

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

	Twelve Months Ended December 31, 2011				
	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Interest Rate Swaps	Total
	(in millions)				
Balance at December 31, 2010	$ 49	$ 5	$ (31)	$	$ 23
Realized and unrealized gains, net of affiliates	13	(4)	(3)	(1)	5
Settlements	(30)	(1)	17		(14)
Deconsolidation of DH	(28)		17	(1)	(12)
Balance at December 31, 2011	$ 4	$	$	$ (2)	$ 2
Unrealized gains (losses) relating to instruments (net of affiliates) still held as of December 31, 2011	$ 3	$	$	$ (2)	$ 1

	Twelve Months Ended December 31, 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 (See Note 16)				50	50
Realized and unrealized gains, net	77		7		84
Purchases	1		2		3
Issuances	(12)		(22)		(34)
Settlements	(23)		(35)		(58)
Balance at December 31, 2010	$ 49	$ 5	$ (31)	$	$ 23
Unrealized gains (losses) relating to instruments still held as of December 31, 2010	$ 64	$	$ (9)	$	$ 55

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Fair Value Measurements (Continued)

	Twelve Months Ended December 31, 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	24	(1)	35	(5)	53
Purchases	49				49
Issuances	(44)		(10)		(54)
Settlements	(30)	(1)	(54)	5	(80)
Transfer into Level 3				(50)	(50)
Balance at December 31, 2009	$ 6	$ 5	$ 17	$ (50)	$ (22)
Unrealized gains (losses) relating to instruments still held as of December 31, 2009	$ 2	$ (1)	$ 5	$ (6)	$

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

Transfers in and/or out of Level 3 represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. Transfers in and/or out of Level 3 are valued at the end of the period. As of December 31, 2009, PPEA held interest rate swaps with a contractual net liability of approximately $80 million. The fair value of these liabilities was estimated to be approximately $50 million due to a valuation adjustment for the deterioration of PPEA's credit worthiness pursuant to fair value accounting standards. As a result of the significance of the credit valuation adjustment, these interest rate swaps were reflected in Level 3 at December 31, 2009.

On January 1, 2010, we adopted ASU No. 2009-17. The adoption of ASU No. 2009-17 resulted in a deconsolidation of our investment in PPEA Holding which was accounted for as an equity method investment until the sale of our interest on November 10, 2010. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion.

We had approximately $10 million and $80 million of Collateral as of December 31, 2011 and 2010, respectively, included in Broker margin account on our consolidated balance sheets. Substantially all of our derivative positions with our derivative counterparties are supported by letters of credit, cash and short-term investment collateral postings or first priority liens on certain of our assets. We do not consider the letters of credit in our valuation of our derivative liabilities unless they are cash collateralized, as they are third-party credit enhancements.

Nonfinancial Assets and Liabilities. The following tables set 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. 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,

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Fair Value Measurements (Continued)

and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

On November 7, 2011, we recorded a loss of the deconsolidation of DH. As a result of the Chapter 11 Cases, we were required to deconsolidate our investment in DH and adjust the carrying amount of our investment in DH to its fair value, which was determined to be zero. 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 November 7, 2011 is considered a Level 3 measurement. Please read Note 3 Chapter 11 Cases Accounting Impact for further discussion of the fair value methodology.

	Fair Value Measurements as of December 31, 2010				
	Level 1	Level 2	Level 3	Total	Total Losses
			(in millions)		
Assets held and used	$	$	$ 275	$ 275	$ (136)
Equity method investment					(37)
Total	$	$	$ 275	$ 275	$ (173)

During the twelve months ended December 31, 2010, long-lived assets held and used were written down to their fair value of $275 million, resulting in pre-tax impairment charges of $136 million, which is included in Impairment and other charges on our consolidated statements of operations. Please read Note 8 Impairment and Restructuring Charges 2010 Impairment Charges for further discussion.

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. 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 period from April 1, 2010 through November 10, 2010, the date we sold our investment in PPEA Holding, we did not recognize our share of losses from our investment in PPEA Holding as we had no further obligation to provide support. Please read Note 8 Impairment and Restructuring Charges 2010 Impairment Charges Other and Note 16 Variable Interest Entities PPEA Holding Company, LLC for further discussion.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Fair Value Measurements (Continued)

	Fair Value Measurements as of December 31, 2009				
	Level 1	Level 2	Level 3	Total	Total Losses
			(in millions)		
Assets/Liabilities:					
Goodwill	$	$	$	$	$ (433)
Assets and liabilities associated with assets related to the LS Power Transactions					(584)
Assets held and used					(212)
Total	$	$	$	$	$ (1,229)

During the first quarter 2009, goodwill with a carrying amount of $433 million was written down to its implied fair value of zero, resulting in an impairment charge of $433 million, which is included in Goodwill impairment on our consolidated statements of operations. Please read Note 17 Goodwill for further discussion and disclosures addressing the description of the inputs and information used to develop the inputs as well as the valuation techniques used to measure the goodwill impairment.

During 2009, long-lived assets held and used were written down to their fair value of zero, resulting in an impairment charge of $212 million, which is included in Impairment and other charges on our consolidated statements of operations. In addition, during the twelve months ended December 31, 2009, net assets/liabilities related to the LS Power Transactions were written down to their fair value of $1,258 million, less costs to sell of $25 million, resulting in an impairment charge of $584 million at September 30, 2009. Of this amount, $326 million is included in Impairment and other charges and $258 million is included in Income (loss) on discontinued operations on our consolidated statements of operations. Please read Note 8 Impairment and Restructuring Charges 2009 Impairment Charges 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 current financial assets and liabilities (cash, accounts receivable, short-term investments and accounts payable) not presented in the table below, approximate fair values due to the short-term maturities of these instruments. The $870 million non-current Accounts payable, affiliate balance with DH does not have a fair value as there are no defined settlement terms. Please read Note 20 Related Party Transactions Transactions with DH Accounts payable, affiliate for further discussion. Unless otherwise noted, the fair value of debt as reflected in the table has been calculated

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Fair Value Measurements (Continued)

based on the average of certain available broker quotes for the periods ending December 31, 2011 and December 31, 2010, respectively.

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Interest rate derivatives designated as fair value accounting hedges (1)	$	$	$ 1	$ 1
Interest rate derivatives not designated as accounting hedges (1)	(2)	(2)	(1)	(1)
Commodity-based derivative contracts not designated as accounting hedges, net of affiliates (1)	7	7	34	34
Term Loan B, due 2013 (2)			(68)	(67)
Term Facility, floating rate due 2013 (2)			(850)	(845)
Undertaking payable to DH (3)	(1,250)	(728)		
DMG Credit Agreement due 2016 (4)	(588)	(603)		
DH Senior Notes and Debentures (5):				
6.875 percent due 2011 (6)			(80)	(79)
8.75 percent due 2012			(89)	(87)
7.5 percent due 2015 (7)			(768)	(592)
8.375 percent due 2016 (8)			(1,043)	(777)
7.125 percent due 2018			(172)	(116)
7.75 percent due 2019			(1,100)	(728)
7.625 percent due 2026			(171)	(107)
DH Subordinated Debentures payable to affiliates, 8.316 percent, due 2027 (9)			(200)	(83)
Sithe Senior Notes, 9.0 percent due 2013 (10)			(233)	(233)
Other (11)			191	191

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

(2) Payment in full was made in August 2011.

(3) The fair value of $728 million for the Undertaking payable to DH represents the $750 million fair value of the Undertaking prepared in connection with the determination of the fair value of our investment in DH as of November 7, 2011 less the $22 million payment made in December 2011. An updated estimate of fair value was not performed at December 31, 2011 because management believed that it was not practicable given the thorough valuation prepared within two months of the balance sheet date. The fair value of the Undertaking payable to DH can be impacted by variability in commodity pricing underlying the valuation analysis and changes in strategy, among other things. Please read Note 3 Chapter 11 Cases for a discussion of the valuation of the Undertaking.

(4) Includes unamortized discounts of $11 million at December 31, 2011.

(5) Unless otherwise noted, the senior notes and debentures were deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Fair Value Measurements (Continued)

(6) Payment in full was made in April 2011, which was the maturity date of this debt.

(7) Includes unamortized discounts of $17 million at December 31, 2010.

(8) Includes unamortized discounts of $4 million at December 31, 2010.

(9) These subordinated debentures were deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

(10) Payment in full was made in September 2011. Please read Note 19 Debt DH Debt Obligations Sithe Senior Notes for further discussion. Includes unamortized premiums of $8 million at December 31, 2010.

(11) Other represents short-term investments, including $85 million of short-term investments included in the Broker margin account, at December 31, 2010.

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

At December 31, 2011, our credit exposure as it relates to the mark-to-market portion of our risk management portfolio totaled $6 million. We seek to reduce our credit exposure by executing agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to further reduce credit risk with certain counterparties by obtaining third party guarantees or collateral as well as the right of termination in the event of default.

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

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

We include cash collateral deposited with counterparties in Broker margin account on our consolidated balance sheets. As of December 31, 2011, we had $10 million posted with these counterparties. We include cash collateral received from counterparties in Accrued liabilities and other current liabilities on our consolidated balance sheets. As of December 31, 2011, we were not holding any collateral received from counterparties.

We have historically used short-term investments to collateralize a portion of our collateral requirements. Our previous broker required that we post approximately 103 percent of any collateral requirement collateralized with short-term investments. Accordingly, our Broker margin account included approximately $3 million related to this requirement at December 31, 2010. Additionally, we posted $7 million of short-term investments which were not utilized as collateral at December 31, 2010. There were no short-term investments in our Broker margin account at December 31, 2011.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11 Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, is included in our stockholders' equity on the consolidated balance sheets, respectively, as follows:

	Year Ended December 31,	
	2011	2010
	(in millions)	
Cash flow hedging activities, net	$ (1)	$ 3
Unrecognized prior service cost and actuarial loss	(52)	(56)
Accumulated other comprehensive loss, net of tax	$ (53)	$ (53)

Note 12 Cash Flow Information

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

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Interest paid (net of amount capitalized)	$ 222	$ 343	$ 400
Taxes paid, net	$ (2)	$ 7	$ 4
Other non-cash investing and financing activity:			
Non-cash capital expenditures (1)	$ 3	$ 1	$ 32
Non-cash capital stock acquisition (2)			443
Other affiliate activity with DH (3)	(1)		

(1) These expenditures related primarily to our interest in the Plum Point Project for the year ended December 31, 2009 and capital expenditures related to the Consent Decree for all years presented. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion of our former interest in the Plum Point Project and Note 23 Commitment and Contingencies for further discussion of the Consent Decree.

(2) Represents the reacquisition of 245 million shares of our Class B common stock valued at $1.81 per share (before giving effect to the reverse stock split of outstanding common stock at a reverse ratio of 1-for-5 completed on May 25, 2010). Please read Note 5 Dispositions Contract Terminations and Discontinued Operations Dispositions LS Power Transactions for further discussion.

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

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 13 Inventory

A summary of our inventories is as follows:

	December 31, 2011	December 31, 2010
	(in millions)	
Materials and supplies	$ 20	$ 64
Coal	36	47
Fuel oil	1	8
Emissions allowances		2
Total	$ 57	$ 121

During the twelve months ended December 31, 2011, 2010 and 2009, we recorded lower of cost or market adjustments of $3 million, $3 million and $18 million, respectively. These charges are included in Cost of sales on our consolidated statements of operations.

Note 14 Property, Plant and Equipment

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

	December 31, 2011	December 31, 2010
	(in millions)	
Generation assets:		
Coal	$ 4,878	$ 4,720
Gas (1)		3,482
DNE (1)		274
IT systems and other		117
	4,878	8,593
Accumulated depreciation (1)	(1,544)	(2,320)
	$ 3,334	$ 6,273

(1) Amounts related to the Gas and DNE segments, as well as IT systems and other, were deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

Total interest costs incurred were $330 million, $348 million and $396 million for the years ended December 31, 2011, 2010, and 2009, respectively. Interest capitalized related to costs of construction projects in process totaled $18 million, $15 million and $24 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Note 15 Unconsolidated Investments

Equity Method Investments

Equity method investments consist of investments in affiliates that we do not control, but where we have significant influence over operations.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15 Unconsolidated Investments (Continued)

Cash distributions received from our equity investments during 2011, 2010 and 2009 were zero, zero and $2 million, respectively. We did not have any undistributed earnings from our equity investments included in accumulated deficit at December 31, 2011, 2010 and 2009.

DH. Effective November 7, 2011, as a result of the commencement of the Chapter 11 Cases, we deconsolidated our investment in DH, a wholly-owned subsidiary, and commenced accounting for our investment in DH using the equity method of accounting. Please read Note 3 Chapter 11 Cases Accounting Impact for further discussion. DH, through its subsidiaries, owns the power generation facilities included in our Gas and DNE segments and also owns the entities that provide services to the Gas, DNE and Coal segments. Please read Note 20 Related Party Transactions for further discussion.

Black Mountain. DH holds a 50 percent ownership interest in Black Mountain, an 85 MW power generation facility in Las Vegas, Nevada. At December 31, 2011 and 2010, the value of this investment was zero. Under a third party power purchase agreement through 2023 for 100 percent of the output of the facility, Black Mountain will receive payments that escalate at a fixed rate over time.

PPEA Holding Company LLC. Until the sale of our interest on November 10, 2010, we owned 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. On January 1, 2010, we adopted ASU No. 2009-17. The adoption of ASU No. 2009-17 resulted in a deconsolidation of our investment in PPEA Holding which was accounted for as an equity method investment until we sold our interest on November 10, 2010. We made a contribution of $15 million during the year ended December 31, 2010 due to a contractual obligation. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion.

Due to the uncertainty and risk surrounding PPEA's financing structure as a result of events that occurred in early 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 consolidated statements of operations. The impairment was a Level 3 non-recurring fair value measurement and reflected our best estimate of third party market participants' considerations including probabilities related to restructuring of the project debt and potential insolvency. Please read Note 10 Fair Value Measurements for further discussion.

On November 10, 2010, we completed the sale of our interest in PPEA Holding to one of the other investors in PPEA Holding. We recognized a loss of approximately $28 million on the sale, which is included in Losses from unconsolidated investments in our consolidated statements of operations. This loss represents $28 million of losses related to interest rate swaps that were previously deferred in Accumulated other comprehensive loss.

Sandy Creek Project. On November 30, 2009, we sold our interests in SCH and SC Services to LS Power. We recorded a loss of $84 million on the sale. Please read Note 5 Dispositions Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further discussion.

DLS Power Development. We previously held a 50 percent ownership interest in DLS Power Holdings and DLS Power Development LLC. The purpose of DLS Power Development was to provide services to DLS Power Holdings and the project subsidiaries related to power project development and

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15 Unconsolidated Investments (Continued)

to evaluate and pursue potential new development projects. Effective January 1, 2009, we entered into an agreement with LS Power Associates, L.P. to dissolve DLS Power Holdings and DLS Power Development LLC. Under the terms of the dissolution, we acquired exclusive rights, ownership and developmental control of substantially all repowering or expansion opportunities related to our existing portfolio of operating assets. LS Power received approximately $19 million in cash from us on January 2, 2009, and acquired full ownership and developmental rights associated with various "greenfield" power generation and transmission development projects not related to our existing operating portfolio of assets. Please read Note 16 Variable Interest Entities DLS Power Holdings and DLS Power Development for further information.

Summarized Financial Information. The following table presents summarized financial information for our wholly-owned unconsolidated investment in DH as of and for the period from November 8, 2011 through December 31, 2011 (in millions):

Current assets	$ 3,569
Non-current assets	4,698
Current liabilities	3,001
Liabilities subject to compromise	4,012
Non-current liabilities	1,216
Revenues	50
Operating loss	(76)
Net loss	(773)

We did not record any losses from our unconsolidated investment in DH for the year ended December 31, 2011 because to do so would have reduced our investment below zero and we do not have an obligation to fund such losses.

Losses from unconsolidated investments for the year ended December 31, 2010 were $62 million, which includes an impairment loss of $37 million, and a loss on the sale of $28 million. These charges were 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. From April 1, 2010 through November 10, 2010, 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 March 31, 2010, and we did not have an obligation to provide further financial support. Please read Note 16 Variable Interest Entities for further discussion.

Losses from unconsolidated investments for the year ended December 31, 2009 were $71 million, which includes $73 million from SCH offset by income of $1 million from Sandy Creek Services, LLC ("SC Services") and $1 million from DLS Power Holdings. In addition to the $7 million noted above, our losses of $73 million from our investment in SCH include a $84 million loss on sale of unconsolidated investment offset by the elimination of $4 million in commitment fees payable to Dynegy that was expensed by SCH. The loss on the sale includes the recognition of $40 million of losses on interest rate swaps that were previously deferred in Accumulated other comprehensive loss on our consolidated balance sheets. Please read Note 16 Variable Interest Entities Sandy Creek Project for further discussion.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 16 Variable Interest Entities

Dynegy Holdings, LLC. Effective November 7, 2011, DH, our wholly-owned subsidiary was deconsolidated. As of December 31, 2011, we did not have any carrying amounts related to our investment in DH included in our consolidated balance sheet. Our maximum exposure to loss related to our investment in DH is limited to our guarantee related to two charter agreements entered into by a DH subsidiary. Please read Note 3 Chapter 11 Cases, Note 15 Unconsolidated Investments and Note 23 Commitments and Contingencies for further discussion. Also, please read Note 20 Related Party Transactions Transactions with DH for a discussion of transactions with DH and its subsidiaries.

Hydroelectric Generation Facilities. On January 31, 2005, we completed the acquisition of ExRes, the parent company of Sithe Energies, Inc. ExRes also owned through its subsidiaries four hydroelectric generation facilities in Pennsylvania. The entities owning these facilities met the definition of VIEs. In accordance with the purchase agreement, Exelon Corporation ("Exelon") had the sole and exclusive right to direct our efforts to decommission, sell, or otherwise dispose of the hydroelectric facilities owned through the VIEs. Exelon was obligated to reimburse us for all costs, liabilities, and obligations of the entities owning these hydroelectric generation facilities, and to indemnify us with respect to the past and present assets and operations of the entities. As a result, we were not the primary beneficiary of the entities and did not consolidate them. During December 2009, we sold two of these facilities and we sold the remaining two units during the third quarter 2010 to a third party as directed by Exelon. We did not record a gain or loss upon completion of the transactions as we did not consolidate these entities and we have no continuing involvement in these entities.

PPEA Holding Company LLC. Until the sale of our interest on November 10, 2010, we owned 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. On September 1, 2010, the Plum Point Power Station commenced commercial operation. PPEA financed its share of construction costs through debt financing. Our obligation to PPEA Holding was limited to our funding commitment of approximately $15 million, which was paid in May 2010. On November 10, 2010, we completed the sale of our interest in PPEA Holding to one of the other investors in PPEA Holding. We recognized a loss of $28 million on the sale, which is included in Losses from unconsolidated investments in our consolidated statements of operations. This loss represents $28 million of losses reclassified from Accumulated other comprehensive loss.

Due to the uncertainty and risk surrounding PPEA's financing structure as a result of events that occurred in early 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 consolidated statements of operations. The impairment was a Level 3 non-recurring fair value measurement and reflected our best estimate of third party market participants' considerations including probabilities related to restructuring of the project debt and potential insolvency. Please read Note 10 Fair Value Measurements for further discussion.

On January 1, 2010, we adopted ASU No. 2009-17. As a result of applying this guidance, we determined that we were not the primary beneficiary of PPEA Holding because we lacked the power to direct the activities that most significantly impact PPEA Holding's economic performance. The activities that most significantly impacted PPEA Holding's economic performance were changes to the costs to construct and operate the facility, modifications to the off-take agreements, and/or changes in the financing structure. As PPEA Holding's LLC Agreement required that those activities be approved by

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 16 Variable Interest Entities (Continued)

all members, the power to direct those activities was shared with the other owners of PPEA Holding and the participants in the 665 MW coal-fired power generation facility (the "Plum Point Project"). Prior to January 1, 2010, we 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). This was recorded as an increase in Accumulated deficit on our consolidated balance sheets as of January 1, 2010. This pre-tax charge reflected the difference in the assets, liabilities and equity (including Other comprehensive loss) that we 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 reflected 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 reflected the risk associated with PPEA Holding's financing arrangement at that date. Please read Note 10 Fair Value Measurements for further discussion about the assumptions used to determine the fair value of our investment as of January 1, 2010. Our consolidated statement of operations included an operating loss of $1 million and a net loss of $7 million related to our investment in PPEA Holding for the twelve months ending December 31, 2009

DLS Power Holdings and DLS Power Development. On April 2, 2007, in connection with the LS Power Merger, we acquired a 50 percent interest in DLS Power Holdings and DLS Power Development. These entities were dissolved effective January 1, 2009. DLS Power Holdings and DLS Power Development met the definition of VIEs, as they required additional subordinated financial support from their owners to conduct normal on-going operations. We determined that we were not the primary beneficiary of the entities because LS Power, a related party, was more closely associated with the entities as they were the managing partner of the entities, owned approximately 40 percent of our outstanding common stock and had three seats on our Board of Directors. Therefore, we did not consolidate the entities.

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

Sandy Creek Project. In connection with our acquisition of a 50 percent interest in DLS Power Holdings, as further discussed above, we acquired a 50 percent interest in SCH, which owns all of SCEA. SCEA owns an undivided interest in the Sandy Creek Project. In August 2007, SCH became a

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Note 16 Variable Interest Entities (Continued)

stand-alone entity separate from DLS Power Holdings, and its wholly-owned subsidiaries, including SCEA, entered into various financing agreements to construct its portion of the Sandy Creek Project.

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

On November 30, 2009, we sold our interests in SCH and SC Services to LS Power. We recorded a loss of $84 million on the sale of these investments in the fourth quarter of 2009. Please read Note 5 Dispositions Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further discussion.

Note 17 Goodwill

Assets and liabilities of companies acquired in purchase transactions are recorded at fair value at the date of acquisition. Goodwill represents the excess purchase price over the fair value of net assets acquired, plus any identifiable intangibles. We previously reviewed goodwill for potential impairment as of November 1st of each year or more frequently if events or circumstances occurred that would more likely than not reduce the fair value of a reporting unit below its carrying amount. During the first quarter 2009, there were several events and circumstances which, when considered in the aggregate, indicated such a reduction in the fair value of our reporting units.

- The first quarter 2009 was characterized by a steep decline in forward commodity prices. Forward market prices for natural gas decreased by 27 percent and 17 percent, respectively, for the calendar years 2009 and 2010, significantly impacting the current market and corresponding forward market prices for power;

- During the first quarter 2009, acquisition activity related to power generation facilities was very low, indicating a lack of demand for such transactions;

- Dynegy's market capitalization continued to decline through the first quarter 2009, with Dynegy's stock price falling from an average of $12.55 (as adjusted for the 1-for-5 reverse stock split of Dynegy's common stock that became effective on May 25, 2010) per share in the fourth quarter 2008 to an average of $8.65 per share (as adjusted for the 1-for-5 reverse stock split of Dynegy's common stock that became effective on May 25, 2010) in the first quarter 2009 and a closing price of $7.05 at March 31, 2009 (as adjusted for the 1-for-5 reverse stock split of Dynegy's common stock that became effective on May 25, 2010); and

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

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

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Note 17 Goodwill (Continued)

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

Consistent with historical practice, on November 1, 2008, we determined the fair value of our reporting units using the income approach based on a discounted cash flows model. This approach used forward-looking projections of our estimated future operating results based on discrete financial forecasts developed by management for planning purposes. Cash flows beyond the discrete forecasts were estimated using a terminal value calculation, which incorporated historical and forecasted financial trends and considered long-term earnings growth rates based on growth rates observed in the power sector. In performing our impairment test at November 1, 2008, the results of our fair value assessment using the income approach were corroborated using market information about recent sales transactions for comparable assets within the regions in which we operate.

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

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

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

For each of the reporting units included in our analysis, fair value assessed using the income approach exceeded the fair value assessed using this market-based approach. However, given that Dynegy's market capitalization had continued to remain below its book equity for more than nine months and given the absence of recent asset sales transaction activity to reasonably corroborate the results of our income approach valuation, we determined that there had been a shift in the manner in which market participants were valuing our business, and believed that the market-based approach had become more relevant for estimating the fair value of our reporting units as of March 31, 2009. We therefore concluded that it was appropriate to place equal weight on the market-based approach (rather than relying primarily on the income approach) for the purpose of determining fair value in

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17 Goodwill (Continued)

step one of the impairment analysis. Based on the results of our analysis discussed above, our reporting units did not pass the first step as of March 31, 2009.

Having determined that the carrying values of the reporting units exceeded their fair values, we performed the second step of the analysis. This second step compared the implied fair value of each reporting unit's goodwill with the carrying amount of such goodwill. We performed a hypothetical allocation of the fair value of the reporting units determined in step one to all of the assets and liabilities of the unit, including any unrecognized intangible assets. After making these hypothetical allocations, we determined no residual value remained that could be allocated to goodwill. As a result, we recorded a $433 million impairment of goodwill to reduce the carrying amount of goodwill to zero.

Note 18 Intangible Assets

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

	LS Power	Sithe	Rocky Road	Total
		(in millions)		
December 31, 2008	$ 209	$ 284	$ 4	$ 497
Additions (1)	15			15
Impairments (2)	(5)			(5)
LS Power Transactions (3)	(5)			(5)
Amortization expense	(11)	(49)	(4)	(64)
December 31, 2009	$ 203	$ 235	$	$ 438
Plum Point Deconsolidation (4)	(193)			(193)
Amortization expense	(7)	(49)		(56)
December 31, 2010	$ 3	$ 186	$	$ 189
DH Deconsolidation (5)	(3)	(145)		(148)
Amortization expense		(41)		(41)
December 31, 2011	$	$	$	$

(1) Represents certain intangible assets we retained upon the dissolution of DLS Power Holdings and DLS Power Development partnerships. Please read Note 16 Variable Interest Entities DLS Power Holdings and DLS Power Development for further discussion of the dissolution.

(2) Represents the impairment of an intangible asset at our Bridgeport power generation facility.

(3) Represents the sale of certain intangibles to LS Power in November 2009. Please read Note 5 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further discussion of the LS Power Transactions.

(4) On January 1, 2010, we adopted ASU No. 2009-17 which resulted in a deconsolidation of our investment in PPEA Holding. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion.

(5) Amounts were deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 18 Intangible Assets (Continued)

LS Power. In April 2007, in connection with the purchase of certain power generation facilities and related contracts from LS Power, we recorded intangible assets of $224 million. $192 million related to the value of PPEA's interest in the Plum Point Project as a result of the construction contracts, debt agreements and related power purchase agreements. This balance was subsequently deconsolidated on January 1, 2010. The remaining $32 million primarily related to power tolling agreements that were amortized over their respective contract terms of 6 months to 7 years. Prior to the DH deconsolidation on November 7, 2011, the amortization expense was being recognized in Revenue in our consolidated statements of operations where we record the revenues received from the contract.

Sithe. Pursuant to our acquisition of Sithe Energies in February 2005, we recorded intangible assets of $657 million. This consisted primarily of a $488 million intangible asset related to a firm capacity sales agreement between Sithe Independence Power Partners and Con Edison, a subsidiary of Consolidated Edison, Inc. That contract provides Independence the right to sell 740 MW of capacity until 2014 at fixed prices that are currently above the prevailing market price of capacity for the New York Rest of State market. This asset will be amortized on a straight-line basis over the remaining life of the contract through October 2014. Prior to the DH deconsolidation on November 7, 2011, the amortization expense was being recognized in Revenue in our consolidated statements of operations where we record the revenues received from the contract.

Rocky Road. Pursuant to our acquisition of NRG's 50 percent ownership interest in the Rocky Road power plant, we recorded an intangible asset in the amount of $29 million. The amortization expense associated with this asset was recognized in Revenue in our consolidated statements of operations where we record the revenues received from the contract. This asset was fully amortized in 2009.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19 Debt

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

	December 31,			
	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Term Loan B, due 2013 (1)	$	$	$ 68	$ 67
Term Facility, floating rate due 2013 (1)			850	845
Undertaking payable to DH (2)	1,250	728		
DMG Credit Agreement, due 2016	599	603		
DH Senior Notes and Debentures (3):				
6.875 percent due 2011 (4)			80	79
8.75 percent due 2012			89	87
7.5 percent due 2015			785	592
8.375 percent due 2016			1,047	777
7.125 percent due 2018			172	116
7.75 percent due 2019			1,100	728
7.625 percent due 2026			171	107
DH Subordinated Debentures payable to affiliates, 8.316 percent, due 2027 (5)			200	83
Sithe Senior Notes, 9.0 percent due 2013 (6)			225	233
	1,849		4,787	
Unamortized premium (discount) on debt, net	(11)		(13)	
	1,838		4,774	
Less: Amounts due within one year, including non-cash amortization of basis adjustments	4		148	
Total Long-Term Debt	$ 1,834		$ 4,626	

(1) Payment in full was made in August 2011.

(2) The fair value of $728 million for the Undertaking payable to DH represents the $750 million fair value of the Undertaking prepared in connection with the determination of the fair value of our investment in DH as of November 7, 2011 less the $22 million payment made in December 2011. An updated estimate of fair value was not performed at December 31, 2011 because management believed that it was not practicable given the thorough valuation prepared within two months of the balance sheet date. The fair value of the Undertaking payable to DH can be impacted by variability in commodity pricing underlying the valuation analysis and changes in strategy, among other things. Please read Note 20 Related Party Transactions Transactions with DH DMG Transfer and Undertaking Agreement for further discussion.

(3) Unless otherwise noted, the senior notes and debentures were deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

(4) Payment in full was made in April 2011, which was the maturity date of this debt.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19 Debt (Continued)

(5) The subordinated debentures were deconsolidated effective November 7, 2011. Please read Note 3 Chapter 11 Cases for further discussion.

(6) Payment in full was made in September 2011. See further discussion below.

Aggregate maturities of the principal amounts of all long-term indebtedness as of December 31, 2011 are as follows: 2013 $4 million, 2014 $4 million, 2015 $3 million, 2016 $573 million and thereafter $1,250 million.

DMG Credit Agreement

In August 2011, DMG entered into a $600 million senior secured term loan facility (the "DMG Credit Agreement"). The DMG Credit Agreement is a senior secured term loan facility with an aggregate principal amount of $600 million, which was borrowed in a single drawing on the closing date. Amounts borrowed under the DMG Credit Agreement that are repaid or prepaid may not be re-borrowed. The DMG Credit Agreement will mature on August 5, 2016 and will amortize in equal quarterly installments in aggregate annual amounts equal to 1.00 percent of the original principal amount of the DMG Credit Agreement with the balance payable on the fifth anniversary of the closing date.

The proceeds of the borrowing under the DMG Credit Agreement were used by DMG to (i) fund cash collateralized letters of credit and provide cash collateral for existing and future collateral requirements, (ii) make a $200 million restricted payment to a parent holding company of DMG, (iii) pay related transaction fees and expenses and (iv) fund additional cash to the balance sheet to provide the DMG asset portfolio with cash to be used for general working capital and general corporate purposes.

All obligations of DMG under (i) the DMG Credit Agreement (the "DMG Borrower Obligations") and (ii) at the election of DMG, hedging/cash management arrangements are unconditionally guaranteed jointly and severally on a senior secured basis (the "DMG Guarantees") by each existing and subsequently acquired or organized direct or indirect material domestic subsidiary of DMG (the "DMG Guarantors"), in each case, as otherwise permitted by applicable law, regulation and contractual provision and to the extent such guarantee would not result in adverse tax consequences as reasonably determined by DMG. None of DMG's parent companies are obligated to repay the DMG Borrower Obligations.

The DMG Borrower Obligations, the DMG Guarantees and any hedging/cash management arrangements are secured by first priority liens on and security interests in 100 percent of the capital stock of DMG and substantially all of the present and after-acquired assets of DMG and each DMG Guarantor. Accordingly, such assets are only available for the creditors of Dynegy Coal Investments Holdings, LLC ("DCIH") and its subsidiaries. DMG has restricted consolidated net assets of approximately $2,664 million as of December 31, 2011.

Interest Costs. The DMG Credit Agreement bears interest, at DMG's option, at either (a) 7.75 percent per annum plus LIBOR, subject to a LIBOR floor of 1.50 percent, with respect to any Eurodollar term loan or (b) 6.75 percent per annum plus the alternate base rate with respect to any ABR term loan. DMG may elect from time to time to convert all or a portion of the term loan from

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19 Debt (Continued)

any ABR Borrowing into a Eurodollar Borrowing or vice versa. With some exceptions, the DMG Credit Agreement is non-callable for the first two years and is subject to a prepayment premium.

On October 19, 2011, we entered into a variety of transactions to hedge interest rate risks associated with the DMG Credit Agreement. We entered into LIBOR interest rate caps at 2 percent with a notional value of $500 million through October 31, 2013. We also entered into LIBOR interest rate swaps with a notional value of $313 million commencing on November 1, 2013 through August 5, 2016. These instruments, which meet the definition of a derivative, have not been designated as accounting hedges and are accounted for at fair value.

Prepayment Provisions. The DMG Credit Agreement contains mandatory prepayment provisions. The outstanding loan under the DMG Credit Agreement is to be prepaid with (a) 100 percent of the net cash proceeds of all asset sales by DMG and its subsidiaries, subject to the right of DMG to reinvest such proceeds if such proceeds are reinvested (or committed to be reinvested) within 12 months and, if so committed to be reinvested, reinvested within six months after such initial 12 month period, (b) 50 percent of the net cash proceeds of issuance of equity securities of DMG and its subsidiaries (except to the extent used (x) to prepay the Loans, (y) for capital expenditures and (z) for permitted acquisitions), (c) commencing with the first full fiscal year of DMG to occur after the closing date, 100 percent of excess cash flow; provided that (i) excess cash flow shall be determined after reduction for amounts used for capital expenditures, and restricted payments and (ii) any voluntary prepayments of the term loans shall be credited against excess cash flow prepayment obligations and (d) 100 percent of the net cash proceeds of issuances, offerings or placements of debt obligations of DMG and its subsidiaries (other than all permitted debt).

Covenants and Events of Default. The DMG Credit Agreement contains customary events of default and affirmative and negative covenants including, subject to certain specified exceptions, limitations on amendments to constitutive documents, liens, capital expenditures, acquisitions, subsidiaries and joint ventures, investments, the incurrence of debt, fundamental changes, asset sales, sale-leaseback transactions, hedging arrangements, restricted payments, changes in nature of business, transactions with affiliates, burdensome agreements, amendments of debt and other material agreements, accounting changes and prepayment of indebtedness or repurchases of equity interests.

The DMG Credit Agreement contains a requirement that DMG shall establish and maintain a segregated account (the "DMG Collateral Posting Account") into which a specified collateral posting amount shall be deposited. DMG may withdraw amounts from the DMG Collateral Posting Account: (i) for the purpose of meeting collateral posting requirements of DMG and the DMG Guarantors; (ii) to prepay the term loan under the DMG Credit Agreement; (iii) to repay certain other permitted indebtedness; and (iv) to the extent any excess amounts are determined to be in the DMG Collateral Posting Account.

The DMG Credit Agreement limits distributions to $90 million per year provided the borrower and its subsidiaries would possess at least $50 million of unrestricted cash and short-term investments on the date of such proposed distribution.

Letter of Credit Facility

In August 2011, DMG entered into a $100 million fully cash collateralized Letter of Credit Reimbursement and Collateral Agreement pursuant to which letters of credit will be issued at DMG's request provided that DMG deposits in an account an amount of cash sufficient to cover the face value of such requested letter of credit plus an additional percentage thereof.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19 Debt (Continued)

Restricted Cash and Investments

The following table depicts our restricted cash and investments:

	December 31, 2011	December 31, 2010
	(in millions)	
DMG LC facility (1)	$ 103	$
DMG Collateral Posting Account (2)	69	
DH Former Credit facility (3)		850
Sithe Energy (4)		40
GEN Finance (5)		50
Total restricted cash and investments	$ 172	$ 940

(1) Includes cash posted to support the letter of credit reimbursement and collateral agreements described above. Please read "Letter of Credit Facility" above for further discussion. Amounts are classified as non-current restricted cash to match the term of the related facility.

(2) Amounts are restricted and may be used for future collateral posting requirements or released per the terms of the DMG Credit Agreement.

(3) Included cash posted to support the letter of credit component of DH's former Fifth Amended and Restated Credit Agreement. The amount was used in the third quarter 2011 to repay the term facility under DH's former Fifth Amended and Restated Credit Agreement.

(4) Included amounts related to the terms of the indenture governing the Sithe Senior Notes. These agreements were terminated as a result of the successful Sithe Tender Offer and the restricted cash was reclassified to cash and cash equivalents during the third quarter 2011.

(5) Included amounts restricted under the terms of a security and deposit agreement associated with a collateral agreement and commodity hedges entered into by GEN Finance. These agreements were terminated and the $50 million held in restricted cash was reclassified to cash and cash equivalents during the first quarter 2011.

DH Debt Obligations

The following is a summary of the debt obligations of DH and its consolidated subsidiaries. DH was deconsolidated effective November 7, 2011 and subsequently accounted for using the equity method of accounting. The deconsolidation of DH resulted in the deconsolidation of approximately $4.6 billion of debt, including $1.1 billion related to DPC. We have included the following disclosure because activity related to the following debt instruments is included in our consolidated financial statements through November 7, 2011.

DPC Credit Agreement. In August 2011, DPC entered into a $1,100 million senior secured term loan facility (the "DPC Credit Agreement"). The DPC Credit Agreement is a senior secured term loan facility with an aggregate principal amount of $1,100 million, which was borrowed in a single drawing

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19 Debt (Continued)

on the closing date. Amounts borrowed under the DPC Credit Agreement that are repaid or prepaid may not be re-borrowed. The DPC Credit Agreement will mature on August 5, 2016 and will amortize in equal quarterly installments in aggregate annual amounts equal to 1.00 percent of the original principal amount of the DPC Credit Agreement with the balance payable on the fifth anniversary of the closing date.

The proceeds of the borrowing under the DPC Credit Agreement were used by DPC to (i) repay an intercompany obligation of a DPC subsidiary to DH and to repay certain outstanding indebtedness under DH's Fifth Amended and Restated Credit Agreement, (ii) fund cash collateralized letters of credit and provide cash collateral for existing and future collateral requirements, (iii) repay approximately $192 million of debt relating to Sithe Energies, Inc. (the intermediate project holding company that indirectly holds the Independence facility in New York), (iv) make a $200 million restricted payment to a parent holding company of DPC, (v) pay related transaction fees and expenses and (vi) fund additional cash to the balance sheet to provide the DPC asset portfolio with liquidity for general working capital and liquidity purposes.

The DPC Credit Agreement limits distributions to $135 million per year provided the borrower and its subsidiaries possess at least $50 million of unrestricted cash and short-term investments on the date of such proposed distribution.

The DPC Credit Agreement bears interest, at DPC's option, at either (a) 7.75 percent per annum plus LIBOR, subject to a LIBOR floor of 1.50 percent, with respect to any Eurodollar term loan or (b) 6.75 percent per annum plus the alternate base rate with respect to any ABR term loan.

On October 19, 2011, DPC entered into a variety of transactions to hedge interest rate risks associated with the DPC Credit Agreement. DPC entered into LIBOR interest rate caps at 2 percent with a notional value of $900 million through October 31, 2013. DPC also entered into LIBOR interest rate swaps with a notional value of $788 million commencing on November 1, 2013 through August 5, 2016. The notional value of the swaps decreases over time, reaching $744 million at the end of the term. These instruments, which meet the definition of a derivative, have not been designated as accounting hedges and are accounted for at fair value.

Letter of Credit Facilities. In August 2011, DPC entered into a two fully cash collateralized Letter of Credit Reimbursement and Collateral Agreements aggregating $515 million pursuant to which letters of credit will be issued at DPC's request provided that DPC deposits in an account an amount of cash sufficient to cover the face value of such requested letter of credit plus an additional percentage thereof.

In August 2011, DH entered into a $26 million fully cash collateralized Letter of Credit Reimbursement and Collateral Agreement pursuant to which letters of credit will be issued at DH's request provided that DH deposits in an account an amount of cash sufficient to cover the face value of such requested letter of credit plus an additional percentage thereof.

Former Credit Facility. During the second quarter 2011, DH borrowed $400 million under its former Fifth Amended and Restated Credit Agreement. This borrowing was repaid on August 5, 2011 in connection with the closing of the New Credit Agreements entered into as part of the Reorganization. Please read Note 1 Organization and Operations Reorganization for further discussion. In addition, in August 2011, DH's former term facility of $850 million was repaid with

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19 Debt (Continued)

current restricted cash and the term loan of $68 million was repaid using proceeds from the DPC Credit Agreement.

Contingent LC Facility. On May 21, 2010, DH executed a new $150 million unsecured bilateral contingent letter of credit facility ("Contingent LC Facility") with Morgan Stanley Capital Group Inc. to provide DH 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 accrues on the unutilized portion of the facility at an annual rate of 0.60 percent and letter of credit availability fees 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 December 31, 2011. The Contingent LC Facility is a pre-petition obligation of DH and DH is not currently paying any facility or availability fees related to the Contingent LC Facility. DH's status as a Debtor Entity may further limit availability pursuant to certain conditions and default events specified in the Contingent LC Facility.

Senior Notes and Subordinated Debentures. In general, DH's senior notes are senior unsecured obligations and rank equal in right of payment to all of DH's existing and future senior unsecured indebtedness, and are senior to all of DH's existing and any of its future subordinated indebtedness. They are not redeemable at DH's option prior to maturity. Dynegy did not guarantee the senior notes, and the assets that DH owns do not secure the senior notes. None of DH's subsidiaries have guaranteed the notes and, as a result, all of the existing and future liabilities of DH's subsidiaries are effectively senior to the notes.

On December 1, 2009, as part of the LS Power Transactions, DH issued to an affiliate of LS Power $235 million aggregate principal amount of its 7.5 percent Senior Unsecured Notes due 2015 (the "Notes") for $214 million in proceeds. In connection with the closing of the LS Power Transactions, DH agreed to offer to exchange the Notes for a new issue of substantially identical notes registered under the Securities Act of 1933. The exchange offer closed on November 8, 2010.

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

In May 1997, NGC Corporation Capital Trust I ("Trust") issued, in a private transaction, $200 million aggregate liquidation amount of 8.316 percent Subordinated Capital Income Securities ("Trust Securities") representing preferred undivided beneficial interests in the assets of the Trust. The Trust invested the proceeds from the issuance of the Trust Securities in an equivalent amount of DH's 8.316 percent subordinated debentures (the "Subordinated Notes"). The sole assets of the Trust are the Subordinated Notes. The Trust Securities are subject to mandatory redemption in whole, but not in part, on June 1, 2027, upon payment of the Subordinated Notes at maturity, or in whole, but not in part, at any time, contemporaneously with the optional prepayment of the Subordinated Notes, as allowed by the associated indenture. The Subordinated Notes are redeemable, at DH's option, at specified redemption prices. The Subordinated Notes represent DH's unsecured obligations and rank subordinate and junior in right of payment to all of DH's senior indebtedness to the extent and in the

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19 Debt (Continued)

manner set forth in the associated indenture. DH has irrevocably and unconditionally guaranteed, on a subordinated basis, payment for the benefit of the holders of the Trust Securities the obligations of the Trust to the extent the Trust has funds legally available for distribution to the holders of the Trust Securities. Since the Trust is considered a VIE, and the holders of the Trust Securities absorb a majority of the Trust's expected losses, DH's obligation is represented by the Subordinated Notes payable to the deconsolidated Trust. DH may defer payment of interest on the Subordinated Notes as described in the indenture, and we deferred our $8 million June 2011 payment of interest. As of December 31, 2011 and 2010, the redemption amount associated with these securities totaled $200 million.

On September 15, 2011, we commenced offers to exchange (the "Exchange Offers") up to $1,250 million principal amount of the outstanding Senior Notes and Subordinated Notes of DH for new Dynegy 10 percent Senior Secured Notes due 2018 and cash. On November 3, 2011, we terminated the Exchange Offers. As a result of the termination, all of the previously tendered (and not validly withdrawn) Senior Notes and Subordinated Notes were not accepted for exchange and were promptly returned to the holders thereof.

On November 7, 2011, DH filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code. Please read Note 3 Chapter 11 Cases for further information.

Sithe Senior Notes. On August 26, 2011, Sithe/ Independence Funding Corporation ("Sithe") commenced a cash tender offer ("Sithe Tender Offer") to purchase Sithe's outstanding $192 million in principal amount of 9.0 percent Secured Bonds due 2013 ("Sithe Senior Notes"). Sithe also solicited consents to certain proposed amendments to the indenture governing the Sithe Senior Notes. At the expiration of the early consent period on September 9, 2011, Sithe entered into a supplemental indenture, which eliminated or modified substantially all of the restrictive covenants, certain events of default and certain other provisions. On September 12, 2011, Sithe accepted for purchase all Sithe Senior Notes validly tendered prior to the consent date and satisfied and discharged the indenture and remaining Sithe Senior Notes. Also on September 12, 2011, Sithe/Independence Power Partners, LP ("SIPP") filed with the New York State Public Service Commission (the "NYPSC"), and certain other parties, a verified petition for approval of financing, seeking NYPSC authorization for SIPP to grant liens/security interests in its assets and properties as collateral security for the DPC Credit Agreement (as defined above). On December 21, 2011, the NYPSC issued an order approving SIPP's request to guarantee, and pledge its collateral in support of, the DPC Credit Agreement. The order approved the proposed financing up to the maximum requested amount of $1.25 billion. Certain other approvals must also be received prior to SIPP granting a security interest.

On the final payment date, September 26, 2011, Sithe accepted to purchase substantially all of the Sithe Senior Notes that were tendered after the consent date. Sithe purchased the Sithe Senior Notes at a price of 108 percent of the principal amount plus consent fees. Total cash paid to purchase the Sithe Senior Notes, including fees and accrued interest, was $217 million, which was funded from proceeds from the DPC Credit Agreement. We recorded a charge of approximately $16 million associated with this transaction, of which $21 million is included in Debt extinguishment costs offset by the write-off of $5 million of premiums included in Interest expense on our consolidated statements of operations. As a result of the successful cash tender offer and consent solicitation, $43 million in restricted cash previously held at Sithe was returned to DPC when the transaction closed.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 20 Related Party Transactions

Transactions with DH

The following table summarizes the Accounts receivable, affiliates, and Accounts payable, affiliates, on our consolidated balance sheet as of December 31, 2011 and cash received (paid) during the period from November 8, 2011 through December 31, 2011 related to various agreements with DH and its consolidated subsidiaries, as discussed below:

	Accounts Receivable, Affiliates	Accounts Payable, Affiliates	Cash Received (Paid)
		(in millions)	
Service Agreements	$ 6	$ 4	$ 16
EMA Agreements	41	22	(1)
Total	$ 47	$ 26	$ 15

Service Agreements. We and certain of our subsidiaries (the "Providers") provide certain services (the "Services") to Dynegy Gas Investments Holdings, LLC ("DGIH"), DCIH, Dynegy Northeast Generation, Inc., their respective subsidiaries and certain of our subsidiaries (the "Recipients"). Service Agreements between us and each of DGIH, DCIH, Dynegy Northeast Generation, Inc. and certain other subsidiaries of Dynegy, which were entered into in connection with the Reorganization, govern the terms under which such Services are provided.

The Providers act as agents for the Recipients for the limited purpose of providing the Services set forth in the Service Agreement. The Providers may perform additional services at the request of the Recipients, and will be reimbursed for all costs and expenses related to such additional services. Prior to the beginning of each fiscal year in which Services are to be provided pursuant to the Service Agreement, the Providers and the Recipients must agree on a budget for the Services, outlining, among other items, the contemplated scope of the Services to be provided in the following fiscal year and the cost of providing each Service. The Recipients will pay the Providers an annual management fee as agreed in the budget, which shall include reimbursement of out-of pocket costs and expenses related to the provision of the Services and will provide reasonable assistance, such as information, services and materials, to the Providers. We recorded income from the Recipients which was offset by expenses incurred with a subsidiary of DH that provided the services. Therefore, there is no impact of the Services Agreement on our consolidated statement of operations for the year ended December 31, 2011.

Energy Management Agreements. Each of our subsidiaries that owns or operates one or more power plants (each an "Internal Customer") has entered into an Energy Management Agency Services Agreement (an "EMA") with Dynegy Power Marketing, LLC ("DPM"), an indirect wholly-owned subsidiary of DH. Pursuant to each EMA, DPM will provide power management services to the Internal Customers, consisting of marketing power and capacity, capturing pricing arbitrage, scheduling dispatch of power, communicating with ISOs or RTOs, purchasing replacement power, and reconciling and settling ISO or RTO invoices. In addition, through DPM's subsidiary, Dynegy Marketing and Trade, LLC, DPM will provide fuel management services, consisting of procuring the requisite quantities of fuel, assisting with storage and transportation, scheduling delivery of fuel, assisting Internal Customers with development and implementation of fuel procurement strategies, marketing and selling excess fuel and assisting with the evaluation of present and long-term fuel purchase and

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 20 Related Party Transactions (Continued)

transportation options. Through DPM's indirect subsidiary, Dynegy Coal Trading & Transportation, LLC, DPM will also provide fuel management services to one or more Internal Customers that require services related to coal. DPM will also assist the Internal Customer with risk management by entering into one or more risk management transactions, the purpose of which is to set the price or value of a commodity or to mitigate or offset changes in the price or value of a commodity. DPM may from time to time provide other services as the parties may agree. Our consolidated statement of operations includes Revenues of $96 million from sales to affiliates and Costs of sales includes $33 million in purchases from affiliates for the period from November 8, 2011 through December 31, 2011.

Tax Sharing Agreement. Under U.S. federal income tax law, we are responsible for the tax liabilities of our subsidiaries because we file consolidated income tax returns. These returns include the income and business activities of the ring-fenced entities (as further discussed below) and our other affiliates. To properly allocate taxes among us and each of our subsidiaries, we and certain of our subsidiaries have entered into a Tax Sharing Agreement under which we agree to prepare consolidated returns on behalf of ourselves and our subsidiaries and make all required payments to relevant revenue collection authorities as required by law. Additionally, DPC and DMG agree to make payments to us of the tax amounts for which DPC or DMG and their respective subsidiaries would have been liable if each group of such subsidiaries began business on the restructuring date (August 5, 2011) and were eligible to, and elected to, file a consolidated return on a stand-alone basis beginning on the restructuring date. Further, each of Dynegy GasCo Holdings, LLC, Dynegy Gas Holdco, LLC, Dynegy Gas Investments Holdings, LLC, Dynegy Coal Holdco, LLC, and Dynegy Coal Investments Holdings, LLC agrees to make payments to us of amounts representing the tax that each such subsidiary would have paid if each began business on the restructuring date and filed a separate corporate income tax return (excluding from income any subsidiary distributions) on a stand-alone basis beginning on the restructuring date.

Cash Management. The Reorganization created new companies, some of which are "bankruptcy remote." In addition, as part of the Reorganization, some companies within our portfolio were reorganized into ring-fenced companies. The special purpose bankruptcy remote entities entered into limited liability company operating agreements, which contain certain restrictions including not allowing the "bankruptcy remote" or "ring-fenced" companies to act as an agent for a non ring-fenced company. Furthermore, bankruptcy remote and ring-fenced companies are required to present themselves to the public as separate entities. They maintain separate books, records and bank accounts and separately appoint officers. Additionally, they pay liabilities from their own funds, they conduct business in their own names (other than any business relating to the trading activities of us and our subsidiaries), they observe a higher level of formalities, and they have restrictions on pledging their assets for the benefit of certain other persons.

Pursuant to our Cash Management Agreement, our ring-fenced entities maintain cash accounts separate from those of our non-ring-fenced entities. Cash collected by a ring-fenced entity is not swept into accounts held in the name of any non-ring-fenced entity and cash collected by a non-ring-fenced entity is not swept into accounts held in the name of any ring-fenced entity. The cash in deposit accounts owned by a ring-fenced entity is not used to pay the debts and/or operating expenses of any non-ring-fenced entity, and the cash in deposit accounts owned by a non-ring-fenced entity is not used to pay the debts and/or operating expenses of any ring-fenced entity. There were no material payments

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 20 Related Party Transactions (Continued)

during the period from November 8, 2011 through December 31, 2011 related to the Cash Management Agreement.

DMG Transfer and Undertaking Agreement. On September 1, 2011, Dynegy and DGIN completed the DMG Transfer. Please read Note 1 Organization and Operations DMG Transfer for further discussion. Our management and Board of Directors, as well as DGIN's board of managers, concluded that the fair value of the acquired equity stake in Coal HoldCo at the time of the transaction was approximately $1.25 billion, after taking into account all debt obligations of DMG, including in particular the DMG Credit Agreement. We provided this value to DGIN in exchange for Coal HoldCo through its obligation, pursuant to the Undertaking Agreement, to make certain specified payments over time which coincide in timing and amount with the payments of principal and interest that DH is obligated to make under a portion of its $1.1 billion of 7.75 percent senior unsecured notes due 2019 and its $175 million of 7.625 percent senior debentures due 2026. The unsecured Undertaking Agreement does not provide any rights or obligations with respect to any outstanding DH notes or debentures, including the notes and debentures due in 2019 and 2026. When our management and Board of Directors, as well as DGIN's board of managers, valued the acquired equity stake of Coal Holdco, they considered many factors, including a valuation range prepared by our financial advisor. Our financial advisor recently informed us that in preparing its valuation range of such equity stake, a mathematical error may have resulted in its valuation range being understated by $100 million. We are continuing to investigate and determine the implications, if any, of this new information.

Immediately after closing the DMG Transfer, DGIN assigned its right to receive payments under the Undertaking Agreement to DH in exchange for a promissory note (the "Promissory Note") in the amount of $1.25 billion that matures in 2027 (the "Assignment"). Our obligations under the Undertaking Agreement will be reduced if the outstanding principal amount of any of DH's $3.5 billion of outstanding notes and debentures is decreased as a result of any exchange offer, tender offer or other purchase or repayment by us or our subsidiaries (other than DH and its subsidiaries, unless we guarantee the debt securities of DH or such subsidiary in connection with such exchange offer, tender offer or other purchase or repayment); provided, that such principal amount is retired, cancelled or otherwise forgiven. Upon the Effective Date, Dynegy and DH will cancel the Undertaking Agreement and Dynegy's obligations under the Undertaking Agreement will be fully satisfied and extinguished.

Subsequent to the deconsolidation of DH, we recorded interest expense of $14 million related to the Undertaking, which is included in Interest expense on our consolidated statement of operations. In addition, we made payments totaling $22 million to DH in December 2011 related to the Undertaking Agreement. As of December 31, 2011, we had approximately $8 million in accrued interest related to the Undertaking, which is reflected in Accrued interest, affiliates on our consolidated balance sheet.

Note receivable, affiliate. On August 5, 2011, Coal HoldCo made a loan to DH of $10 million with a maturity of 3 years and an interest rate of 9.25 percent per annum. As a result of DH's bankruptcy filing, we determined it was probable that Coal HoldCo would not collect any amounts due associated with the note and the note was impaired. We recorded a charge of $10 million related to the impairment of the note, which is included in Other income and expense, net on our consolidated statement of operations.

Accounts payable, affiliate. We have historically recorded intercompany transactions in the ordinary course of business, including the reallocation of deferred taxes between legal entities in accordance with applicable IRS regulations. As a result of such transactions, we have recorded over time a payable to

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 20 Related Party Transactions (Continued)

DH and its affiliates in the aggregate amount of $846 million and $814 million at December 31, 2011 and 2010, respectively. This amount is classified within long-term liabilities as Accounts payable, affiliates as there are no defined payment terms, it is not evidenced by any promissory note and there has never been an intent for payment to occur. Historically, this amount has eliminated in consolidation; however, upon the deconsolidation of DH and its consolidated subsidiaries, the amount is reflected as a payable to affiliates on our December 31, 2011 consolidated balance sheet. The creditors' committee of DH contends that DH may possess a cause of action against us for payment of the intercompany receivable. By letter dated February 29, 2012, the creditors' committee made demand on DH to pursue a cause of action against us for payment of the intercompany receivable or, alternatively, requesting that DH agree that the creditors' committee may commence and prosecute such action (the "Demand Letter"). The creditors' committee contends that if DH declines to pursue such action, the creditors' committee will seek standing from the Bankruptcy Court to bring an action on behalf of DH's estate. We do not believe that a valid and enforceable right of payment of the intercompany amount exists and intend to oppose any efforts seeking payment of this amount.

DH Employee benefits. Our employees, and employees of DH, participate in the stock compensation, pension and other post-retirement benefit plans sponsored by us. Please read Note 25 Employee Compensation, Savings and Pension Plans for further discussion.

Transactions with LS Power

On November 30, 2009, we sold certain assets to LS Power, including our interest in two investments in joint ventures in which LS Power or its affiliates were also investors. Please read Note 5 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further discussion.

We had 50 percent ownership interests in SCEA and SC Services, and subsidiaries of LS Power held the remaining 50 percent interests. We recorded a loss of approximately $84 million related to this sale in the fourth quarter 2009. Please read Note 16 Variable Interest Entities Sandy Creek Project for further discussion.

We held two other investments in joint ventures in which LS Power or its affiliates were also investors a 50 percent ownership interest in DLS Power Holdings and DLS Power Development. In December 2008, Dynegy and LS Power Associates, L.P. agreed to dissolve the two companies' development joint venture.

Upon completion of the agreement with LS Power discussed above, assets related to repowering or expansion opportunities at the Bridgeport and Arizona power generating facilities were transferred to LS Power in connection with the sale of those facilities. Please read Note 16 Variable Interest Entities DLS Power Holdings and DLS Power Development for further information.

Other

December 2001 Equity Purchases. In December 2001, ten former members of our senior management purchased Class A common stock from us in a private placement pursuant to Section 4(2) of the Securities Act of 1933. These former officers received loans from us totaling approximately $25 million to purchase our common stock at a price of $19.75 per share (before giving effect to the reverse stock split of outstanding common stock at a reverse ratio of 1-for-5 completed on May 25,

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 20 Related Party Transactions (Continued)

2010), the same price as the net proceeds per share received by us from a concurrent public offering. The loans bear interest at 3.25 percent per annum and are full recourse to the borrowers. Such loans, whose balances totaled $2 million as of December 31, 2011 and 2010, respectively, are accounted for as subscriptions receivable within our stockholders' equity on the consolidated balance sheets.

Note 21 Income Taxes

Income Tax Benefit. We are subject to U.S. federal and state income taxes on our operations.

Our loss from continuing operations before income taxes was $2,277 million, $432 million and $1,355 million for the years ended December 31, 2011, 2010 and 2009, respectively, which was solely from domestic sources.

Our components of income tax benefit related to loss from continuing operations were as follows:

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Current tax expense	$	$ (1)	$ (3)
Deferred tax benefit	632	198	318
Income tax benefit	$ 632	$ 197	$ 315

Our income tax benefit related to loss from continuing operations for the years ended December 31, 2011, 2010 and 2009, was equivalent to effective rates of 28 percent, 46 percent and 23 percent, respectively. Differences between taxes computed at the U.S. federal statutory rate and our reported income tax benefit were as follows:

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
Expected tax benefit at U.S. statutory rate (35%)	$ 797	$ 151	$ 474
State taxes (1)	139	28	25
Permanent differences (2)	(2)	(1)	(175)
Valuation allowance (3)	(1,235)	(1)	(12)
IRS and state audits and settlements		18	8
Loss on deconsolidation of DH (4)	931		
Other	2	2	(5)
Income tax benefit	$ 632	$ 197	$ 315

(1) We incurred a state tax benefit for the year ended December 31, 2011 due to current year losses and an $8 million audit adjustment offset by a $3 million expense due to a change in Illinois tax law. We incurred a state tax benefit for the year ended December 31, 2010 due to current year losses that will reduce future state cash taxes as well as changes in our state sales profile and a change in California tax law. We incurred a state tax benefit for the year ended December 31, 2009 due to current year losses which will reduce future state cash taxes, changes in our state sale profile, and the exit from various states due to

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 21 Income Taxes (Continued)

the LS Power Transactions adjustments arising from measurement of temporary differences.

(2) Includes $151 million related to nondeductible goodwill impairment expense and $18 million related to nondeductible losses in connection with the LS Power transaction for the year ended December 31, 2009.

(3) We recorded a valuation allowance of $1,235 million during the year ended December 31, 2011 to reserve our net deferred tax assets.

(4) Upon deconsolidation of DH, we recorded a deferred tax asset for the difference between the carrying value of our investment in DH of zero and our outside tax basis in the stock of DH of $3,910 million.

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

	Year ended December 31,	
	2011	2010
	(in millions)	
Deferred tax assets:		
Current:		
Reserves (legal, environmental and other)	$ 1	$ 11
Miscellaneous book/tax recognition differences	11	3
Subtotal	12	14
Less: valuation allowance	(7)	(2)
Total current deferred tax assets	5	12
Non-current:		
Investment in unconsolidated subsidiaries	1,569	
NOL carryforwards	51	262
AMT credit carryforwards	271	271
Reserves (legal, environmental and other)		2
Other comprehensive income	33	34
Miscellaneous book/tax recognition differences	35	25
Subtotal	1,959	594
Less: valuation allowance	(1,250)	(20)
Total non-current deferred tax assets	709	574
Deferred tax liabilities:		
Non-current:		
Depreciation and other property differences	(701)	(1,215)
Power contract	(13)	
Total non-current deferred tax liabilities	(714)	(1,215)

Net deferred tax asset (liability)	$		$	(629)

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Note 21 Income Taxes (Continued)

NOL Carryforwards. At December 31, 2011, we had approximately $128 million of regular federal tax NOL carryforwards and $325 million of AMT NOL carryforwards. The federal and AMT NOL carryforwards will expire beginning in 2027 and 2024, respectively. As a result of the application of certain provisions of the Internal Revenue Code, we incurred an ownership change in May 2007 that placed an annual limitation on our ability to utilize certain tax carryforwards, including our NOL carryforwards. We do not expect that the ownership change will have any impact on our future tax liability. We do not believe we will produce sufficient future taxable income, nor are there tax planning strategies available, to utilize existing tax attributes, including the federal and AMT NOL carryforwards; therefore, a valuation allowance of $44 million has been recorded as of December 31, 2011, for the amount of tax benefits represented by Federal and AMT NOL carryforwards not otherwise realized by reversing temporary differences.

At December 31, 2011 and 2010, state NOL carryforwards totaled $127 million and $786 million, respectively.

AMT Credit Carryforwards. At December 31, 2011, we had approximately $271 million of AMT credit carryforwards. The AMT credit carryforwards do not expire. As a result of the application of certain provisions of the Internal Revenue Code, we incurred an ownership change on May 2007 that placed an annual limitation on our ability to utilize certain tax carryforwards, including our AMT credits. We do not expect that the ownership change will have any impact on our future tax liability. We do not believe we will produce sufficient future taxable income, nor are there tax planning strategies available, to utilize existing tax attributes, including the federal and AMT credit carryforwards; therefore, a valuation allowances of $271 million has been recorded as of December 31, 2011 for the amount of tax benefits represented by deferred tax assets not otherwise realized by reversing temporary differences.

Change in Valuation Allowance. Realization of our deferred tax assets is dependent upon, among other things, our ability to generate taxable income of the appropriate character in the future. At December 31, 2011, valuation allowances related to federal and state NOL carryforwards and credits have been established. Additionally, at December 31, 2011, our temporary differences were in a net deferred tax asset position. We do not believe we will produce sufficient future taxable income, nor are there tax planning strategies available, to realize the tax benefits of our net deferred tax asset associated with temporary differences. Accordingly, we have recorded a full valuation allowance against the temporary differences.

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

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 21 Income Taxes (Continued)

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

	Temporary Differences	Capital Loss Carryforwards	AMT Credit Carryforwards	Federal NOL Carryforwards and Credits	State NOL Carryforwards and Credits	Foreign NOL Carryforwards and Deferred Tax Assets	Total
				(in millions)			
Balance as of December 31, 2008	$	$ (10)	$	$	$ (23)	$ (4)	$ (37)
Changes in valuation allowance continuing operations					(12)		(12)
Other release		10				4	14
Balance as of December 31, 2009					(35)		(35)
Changes in valuation allowance continuing operations					1		1
Other release					12		12
Balance as of December 31, 2010					(22)		(22)
Changes in valuation allowance continuing operations	(935)		(271)	(44)	15		(1,235)
Balance as of December 31, 2011	$ (935)	$	$ (271)	$ (44)	$ (7)	$	$ (1,257)

Unrecognized Tax Benefits. We file a consolidated income tax return in the U.S. federal jurisdiction, and we file income tax returns in various states. We are no longer subject to U.S. federal income tax examinations for the years prior to 2007, and with few exceptions, we are no longer subject to state and local examinations prior to 2007. We are no longer subject to non-U.S. income tax examinations. Our federal income tax returns are routinely audited by the IRS, and provisions are routinely made in the financial statements in anticipation of the results of these audits. We finalized the IRS audit of 2008-2009 tax years in the third quarter 2011. As a result of the settlement of our 2008-2009 audit, adjustments to tax positions related to prior years, and various state settlements, we recorded, and included in our income tax expense, a benefit of $1 million, a benefit of $18 million and a benefit of $5 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 21 Income Taxes (Continued)

A reconciliation of our beginning and ending amounts of unrecognized tax benefits follows (in millions):

Balance at December 31, 2008	$	32
Additions based on tax positions related to the prior year		6
Reductions based on tax positions related to the prior year		(4)
Settlements		(9)
Balance at December 31, 2009	$	25
Additions based on tax positions related to the prior year		
Reductions based on tax positions related to the prior year		(1)
Settlements		(19)
Balance at December 31, 2010	$	5
Additions based on tax positions related to the prior year		
Reductions based on tax positions related to the prior year		
Settlements		(1)
Balance at December 31, 2011	$	4

As of December 31, 2011, 2010 and 2009, approximately $4 million, $5 million and $24 million, respectively, of unrecognized tax benefits would impact our effective tax rate if recognized.

The changes to our unrecognized tax benefits during the twelve months ended December 31, 2011 primarily resulted from changes in various federal and state audits and positions. The adjustments to our reserves for uncertain tax positions as a result of these changes had an insignificant impact on our net income.

During the years ended December 31, 2011, 2010 and 2009, we recognized less than $1 million in interest and penalties. We had approximately $2 million, $2 million and $2 million accrued for the payment of interest and penalties at December 31, 2011, 2010 and 2009, respectively.

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

Note 22 Loss Per Share

The reconciliation of basic loss per share from continuing operations to diluted loss per share from continuing operations of our common stock outstanding during the period is shown in the following table. Diluted loss per share represents the amount of losses for the period available to each share of our common stock outstanding during the period plus each share that would have been outstanding

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 22 Loss Per Share (Continued)

assuming the issuance of common shares for all dilutive potential common shares outstanding during the period.

	Year Ended December 31,		
	2011	2010	2009
	(in millions, except per share amounts)		
Loss from continuing operations	$ (1,645)	$ (235)	$ (1,040)
Less: Net loss attributable to the noncontrolling interests			(15)
Loss from continuing operations attributable to Dynegy Inc. for basic and diluted loss per share	$ (1,645)	$ (235)	$ (1,025)
Basic weighted-average shares (1)	122	120	164
Effect of dilutive securities stock options and restricted stock (1)		1	1
Diluted weighted-average shares (1)	122	121	165
Loss per share from continuing operations attributable to Dynegy Inc.:			
Basic (1)	$ (13.48)	$ (1.96)	$ (6.25)
Diluted (1)(2)	$ (13.48)	$ (1.96)	$ (6.25)

(1) On May 25, 2010, we 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 and all prior periods have been adjusted to reflect the reverse stock split. Please read Note 24 Capital Stock Common Stock for further discussion.

(2) When an entity has a net loss from continuing operations adjusted for preferred dividends, it is prohibited from including potential common shares in the computation of diluted per-share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for all periods presented.

Note 23 Commitments and Contingencies

Legal Proceedings

Set forth below is a summary of our material ongoing legal proceedings. Pursuant to the requirements of FASB ASC 450 and related guidance, we record accruals for estimated losses from contingencies when available information indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. In addition, we disclose matters for which management believes a material loss is reasonably possible. In all instances, management has assessed the matters below based on current information and made judgments concerning their potential outcome, giving consideration to the nature of the claim, the amount, if any, and nature of damages sought and the probability of success. Management regularly reviews all new information with respect to each such contingency and adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties including unfavorable rulings or developments, it is

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Note 23 Commitments and Contingencies (Continued)

possible that the ultimate resolution of our legal proceedings could involve amounts that are different from our currently recorded accruals and that such differences could be material.

In addition to the matters discussed below, we are party to other routine proceedings arising in the ordinary course of business or related to discontinued business operations. Any accruals or estimated losses related to these matters are not material. In management's judgment, the ultimate resolution of these matters will not have a material effect on our financial condition, results of operations or cash flows.

Bondholder Litigation. On September 21, 2011, an ad-hoc group of bondholders (the "Avenue Plaintiffs") of DH filed a complaint in the Supreme Court of the State of New York, County of New York, captioned *Avenue Investments, L.P. et al v. Dynegy Inc., Dynegy Holdings, LLC, Dynegy Gas Investments, LLC, Clint C. Freeland, Kevin T. Howell and Robert C. Flexon* (Index No. 652599/11) ("Avenue Investments Matter"). The Avenue Plaintiffs challenge the DMG Transfer. On September 27, 2011, the successor indenture trustees under the Roseton and Danskammer Indenture Agreements (the "Indenture Trustee Plaintiffs") filed a complaint in the Supreme Court of the State of New York, captioned *The Successor Lease Indenture Trustee et al v. Dynegy Inc., Dynegy Holdings, LLC, Dynegy Gas Investments, LLC, E. Hunter Harrison, Thomas W. Elward, Michael J. Embler, Robert C. Flexon, Vincent J. Intrieri, Samuel Merksamer, Felix Pardo, Clint C. Freeland, Kevin T. Howell John Doe 1, John Doe 2, John Doe 3, Etc.* (Index No. 652642/2011). The Indenture Trustee Plaintiffs similarly challenge the DMG Transfer. Plaintiffs in both actions allege, among other claims, breach of contract, breach of fiduciary duties, and violations of prohibitions on fraudulent transfers in connection with the DMG Transfer and also seek to have the DMG Transfer set aside, and request unspecified damages as well as attorneys' fees. We filed motions to dismiss the actions on October 31, 2011. On November 7, 2011, Dynegy, DH and the Consenting Noteholders (as defined in Note 3 Chapter 11 Cases) agreed to enter into a stipulation that suspends the prosecution of the Consenting Noteholders' claims in the Avenue Investments Matter.

On November 4, 2011, the owner-lessors of the Danskammer and Roseton facilities (the "Owner Lessor Plaintiffs") filed a lawsuit in NY state court, captioned *Resources Capital Management Corp., Roseton OL, LLC and Danskammer OL, LLC, v. Dynegy Inc., Dynegy Holdings, Inc., Dynegy Holdings, LLC, Dynegy Gas Investments, LLC, Thomas W. Elward, Michael J. Embler, Robert C. Flexon, E. Hunter Harrison, Vincent J. Intrieri, Samuel J. Merksamer, Felix Pardo, Clint. C. Freeland, Kevin T. Howell, Icahn Capital LP, and Seneca Capital Advisors, LLC*, alleging, among other claims, that the Reorganization, the DPC and DMG Credit Agreements, and the DMG Transfer constitute an integrated scheme involving fraudulent transfers, breach of contract, and breach of fiduciary duties, and seek a judgment to unwind all the transactions.

On November 21, 2011, the defendants filed in each action a Notice of Filing of Bankruptcy Petition and of the Automatic Stay, which provided, among other things, that (i) "pursuant to section 362(a) of the Bankruptcy Code, this lawsuit is stayed in its entirety, as to all claims and all defendants (the "Automatic Stay")," and (ii) "actions taken in violation of the Automatic Stay are void and may subject the person or entity taking such actions to the imposition of sanctions by the Bankruptcy Court. In addition, on November 21, 2011, the defendants filed two stipulations in the Avenue Litigation and a stipulation in the Trustee Litigation, pursuant to which the parties agreed, among other things, (i) to stay or take no action in the Lawsuits, including the pending motions to

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 23 Commitments and Contingencies (Continued)

dismiss, until further application, and (ii) to reserve all rights and/or arguments with respect to the scope or effect of the Automatic Stay. Please read Note 3 Chapter 11 Cases for further discussion.

We believe the plaintiffs' complaints in all three lawsuits lack merit and we will continue to oppose their claims vigorously.

Stockholder Litigation Relating to the Blackstone and Icahn Merger Agreements. In connection with the 2010 and 2011 terminations of the merger agreement with an affiliate of The Blackstone Group L.P. and the merger agreement with an affiliate of Icahn Enterprises L.P., respectively, numerous stockholder lawsuits and one stockholder derivative lawsuit previously filed in the District Courts of Harris County, Texas, the Southern District of Texas, and the Court of Chancery of the State of Delaware were dismissed. In July 2011, the Harris County District Court granted the motion of the plaintiff's lead class counsel for an award of attorney's fees and expenses in the amount of approximately $2 million. We have appealed the decision.

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. All of the remaining 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 on preemption of plaintiffs' state law claims, which were filed shortly thereafter. Plaintiffs concurrently moved to amend their complaints to add federal claims. In October 2010, the court denied plaintiffs' motion to amend.

On July 18, 2011, the Court granted defendants' motions for summary judgment, thereby dismissing all of plaintiffs' state law claims. Plaintiffs have appealed the decision to the Ninth Circuit Court of Appeals.

Plaintiff in one of the pending actions, *Multiut Corporation v. Dynegy Inc. et al*, had previously filed similar claims under federal law, which are not subject to the Court's July 18, 2011 order. Multiut Corporation is presently proceeding before the United States Bankruptcy Court for the Northern District of Illinois, Eastern Division having petitioned for Chapter 11 protection in May 2009. In April 2011, the bankruptcy court denied confirmation of Multiut's proposed plan of reorganization and entered an order converting the case under Chapter 7 of the bankruptcy code and appointed a Trustee to oversee the liquidation of Multiut's assets, one of which is Multiut's claim against us in the gas index litigation. We settled Multiut's claim with the Trustee and it was dismissed.

Illinova Generating Company Arbitration. In May 2007, our subsidiary Illinova Generating Company ("IGC") received an adverse award in an arbitration brought by Ponderosa Pine Energy, LLC ("PPE"). The award required IGC to pay PPE $17 million, which IGC paid in June 2007 under protest while simultaneously seeking to vacate the award in the District Court of Dallas County, Texas. In March 2010, the Dallas District Court vacated the award, finding that one of the arbitrators had exhibited evident partiality. PPE is appealing that decision to the Fifth District Court of Appeals in Dallas, Texas. Coincident with the appeal, IGC filed a claim against PPE seeking recovery of the $17 million plus interest. In September 2010, the Dallas District Court ordered PPE to deposit the $17 million principal in an interest-bearing escrow account jointly owned by IGC and PPE pending the

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 23 Commitments and Contingencies (Continued)

Dallas Court of Appeals decision, which has not yet been issued. As a result of the uncertainty surrounding the outcome of PPE's appeal, our receivable from PPE is fully reserved at December 31, 2011.

Other Commitments and Contingencies

In conducting our operations, we have routinely entered into long-term commodity purchase and sale commitments, as well as agreements that commit future cash flow to the lease or acquisition of assets used in our businesses. These commitments have been typically associated with commodity supply arrangements, capital projects, reservation charges associated with firm transmission, transportation, storage and leases for office space, equipment, plant sites, power generation assets and LPG vessel charters. The following describes the more significant commitments outstanding at December 31, 2011.

Coal Commitments. At December 31, 2011, we had contracts in place to supply coal to various of our generation facilities with minimum commitments of $441 million. Obligations related to the purchase of coal were $433 million through 2015, and obligations related to the transportation were $8 million through 2013.

Consent Decree. In 2005, we settled a lawsuit filed by the EPA and the United States Department of Justice in the U.S. District Court for the Southern District of Illinois that alleged violations of the Clean Air Act and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Baldwin generating station. A consent decree (the "Consent Decree") was finalized in July 2005. Among other provisions of the Consent Decree, we are required to not operate certain of our power generating facilities after specified dates unless certain emission control equipment is installed. As of December 31, 2011, only Baldwin Unit 2 has material Consent Decree work yet to be performed, which is scheduled to be completed by the end of 2012. We have spent approximately $872 million through December 31, 2011 related to these Consent Decree projects.

Blackstone Merger Agreement. On August 13, 2010, we entered into the Blackstone Merger Agreement with an affiliate of Blackstone, pursuant to which we would be acquired and our stockholders would receive $4.50 per share in cash. On November 16, 2010, the agreement was amended to increase the merger consideration to $5.00 per share in cash. The Blackstone Merger Agreement was not approved by our stockholders at a special stockholders' meeting on November 23, 2010 and was subsequently terminated by the parties in accordance with the terms of the agreement. The Blackstone Merger Agreement requires us to pay Blackstone a termination fee in the amount of approximately $16 million in the event that within 18 months of November 23, 2010, we consummate an alternative transaction having an aggregate value of more than $4.50 per share.

Icahn Merger Agreement. On December 15, 2010, our Board of Directors unanimously approved us entering into the Icahn Merger Agreement with an affiliate of Icahn. In connection with the Icahn Merger Agreement, Icahn launched the Tender Offer on December 22, 2010 for all of the issued and outstanding shares of common stock at $5.50 per share. At the expiration of the Tender Offer on February 18, 2011, an insufficient number of shares had been tendered in response to the Tender Offer, and as a result the Icahn Merger Agreement automatically terminated. In connection with the termination, we paid $5 million to Icahn with respect to expenses incurred by Icahn related to the Icahn Merger Agreement in February 2011, and may be required to pay additional fees of $11 million in the event that within 18 months of February 18, 2011, we consummate an alternative transaction having an aggregate value of more than $5.50 per share.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 23 Commitments and Contingencies (Continued)

Vermilion and Baldwin Groundwater. We have implemented groundwater monitoring plans for the Coal Combustion Residuals ("CCR") surface impoundment at our Baldwin facility and for two CCR surface impoundments at our Vermilion facility in response to a request by the Illinois EPA. Groundwater monitoring results indicate that these CCR surface impoundments impact onsite groundwater at these sites. We have agreed to submit to the Illinois EPA by April 1, 2012 a proposed corrective action plan for these CCR surface impoundments at the Vermilion facility. At this time we cannot reasonably estimate the costs of corrective action that ultimately may be required at Vermilion. At the request of the Illinois EPA, we have initiated an investigation at the Baldwin facility to determine if the facility's CCR surface impoundment impacts offsite groundwater. If offsite groundwater impacts are identified and remediation measures are necessary in the future, we may incur significant costs that could have a material adverse effect on our financial condition and cash flows. At this time we cannot reasonably estimate the costs of corrective action that ultimately may be required at Baldwin.

Other Minimum Commitments. Minimum commitments in connection with office space, equipment, plant sites and other leased assets at December 31, 2011, were as follows: 2012 $2 million, 2013 $3 million, 2014 $2 million, 2015 $2 million, 2016 $2 million and beyond $10 million.

Rental payments made under the terms of these arrangements totaled $11 million, $107 million and $154 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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 less than $1 million as of December 31, 2011.

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

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 23 Commitments and Contingencies (Continued)

claims related to the Riverside/Foothills Project for certain aspects of the project. Namely, LS Power has been indemnified for any disputes that arise as to ownership, transfer of bonds related to the project, and any failure by us to obtain approval for the transfer of the payment in-lieu of taxes program already in place. The indemnities related solely to the Riverside/Foothills Project are capped at a maximum of $180 million and extend until the earlier of the expiration of the tax agreement or December 26, 2026. At this time, we have incurred no significant expenses under these indemnities. Please read Note 5 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations LS Power Transactions for further discussion.

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 and ultimately remanded back to FERC for further review. On May 24, 2011 and May 26, 2011, FERC issued two orders in these dockets. The first order denied the request of the California Parties for consolidation of various dockets and denied their request for summary disposition on market manipulation issues. The second order addressed treatment of settled parties and the scope of hearing issues in the ongoing proceedings.

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 of less than $1 million for remediation of groundwater contamination at the Breckenridge Gas Processing Plant sold by DMSLP in 2001. The indemnification provided by DMSLP to the purchaser of the plant has a limit of $5 million.

Illinois Power Indemnities. We have 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 our liability under this indemnity, the amount of the indemnity is limited to 50 percent of any such losses. We have made certain payments in respect of these indemnities following regulatory action by the ICC, and have established reserves for further potential indemnity claims. Further events, which fall within the scope of the indemnity, may still occur. However, we are 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. We intend to contest any proposed regulatory actions.

VLGC Guarantee. A subsidiary of DH is party to two charter party agreements relating to VLGCs previously utilized in our former global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $18 million for 2012, and approximately $23 million in aggregate for the period from 2013 through lease expiration. The charter party rates payable under the

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 23 Commitments and Contingencies (Continued)

two charter party agreements float in accordance with market based rates for similar shipping services. The $18 million and $23 million amounts set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary term of one charter is through September 2013 while the primary term of the second charter is through September 2014. On January 1, 2003, both VLGCs were sub-chartered to a wholly-owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements. We have guaranteed the obligation of the DH subsidiary related to the charter agreements.

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 December 31, 2011, 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 24 Capital Stock

At December 31, 2011, we 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 December 31, 2011, there were no shares of preferred stock issued or outstanding.

Preferred Stock. We have authorized preferred stock consisting of 20,000,000 shares, $0.01 par value. Our preferred stock may be issued from time to time in one or more series, the shares of each series to have such designations and powers, preferences, rights, qualifications, limitations and restrictions thereof as specified by our Board of Directors.

Common Stock. At December 31, 2011, there were 123,585,877 shares of our common stock issued in the aggregate and 731,407 shares were held in treasury. During 2011 and 2010, no quarterly cash dividends were paid by us.

On May 25, 2010, we effected a reverse stock split of our outstanding common stock at a ratio of 1-for-5 and proportionately decreased the number of authorized shares of our capital stock. All prior periods have been adjusted to reflect the reverse stock split. As a result, our authorized capital decreased from 2,100,000,000 shares of common stock to 420,000,000 shares of common stock and our 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 2007, we established two classes of common shares, Class A and Class B. All of our outstanding Class B common stock was owned by the LS Power. On November 30, 2009, as part of the LS Power Transactions, we purchased 245 million shares of Dynegy's Class B common stock. The remaining 95 million shares of our Class B common stock then held by LS Power were converted to our Class A common shares. As a result of the LS Power Transactions, there are currently no outstanding Class B common shares.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 24 Capital Stock (Continued)

Common stock activity for the three years ended December 31, 2011 was as follows:

	Class A Common Stock		Class B Common Stock held by LS Power	
	Shares	Amount	Shares	Amount
	(in millions)			
December 31, 2008	101	$ 1	68	$ 1
401(k) plan and profit sharing	1			
LS Power Transactions:				
Conversion of LS Power Class B shares to Class A shares	19		(19)	
Retirement of Class B shares			(49)	(1)
December 31, 2009	121	$ 1		$
401(k) plan and profit sharing	1			
December 31, 2010	122	$ 1		$
Options exercised	1			
401(k) plan and profit sharing	1			
December 31, 2011	124	$ 1		$

Treasury Stock. During 2011, 2010 and 2009, common shares purchased into treasury totaled 103,393 shares, 70,337 shares and 44,019 shares, respectively. All of the purchases were related to shares withheld to satisfy income tax withholding requirements in connection with forfeitures of restricted stock awards.

As a result of the reverse stock split, the number of common stock shares held as treasury stock at May 25, 2010 decreased from 3,137,959 shares to 627,591 shares.

Stock Award Plans. We have four stock award plans, all of which provided for the issuance of authorized shares of our common stock. Restricted stock awards and option grants were issued under the plans. Each option granted is exercisable at a strike price, which ranges from $4.03 per share to $48.35 per share for options currently outstanding. A brief description of each plan is provided below:

Dynegy 2000 LTIP. This annual compensation plan, created for all employees upon Illinova's merger with us, provided for the issuance of 2,000,000 authorized shares through June 2009. Grants from this plan vest in equal annual installments over a three-year period, and options will expire ten years from the date of the grant.

Dynegy 2001 Non-Executive LTIP. This plan is a broad-based plan and provides for the issuance of 2,000,000 authorized shares through September 2011. Grants from this plan vest in equal annual installments over a three-year period, and options will expire no later than ten years from the date of the grant. This plan was frozen as to issuance of new awards.

Dynegy 2002 LTIP. This annual compensation plan provided for the issuance of 2,000,000 authorized shares through May 2012. Grants from this plan vest in equal annual installments over a three-year period, and options will expire no later than ten years from the date of the grant. Following the approval of the Dynegy 2010 LTIP, this plan was frozen as to issuance of new awards.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 24 Capital Stock (Continued)

Dynegy 2010 LTIP. This plan is a broad-based plan and provides for the issuance of 3,700,000 authorized shares through May 2020. Any performance-based stock awards, stock units and other "full-value awards" will generally be subject to a performance period of at least one year and if not performance-based generally subject to a restriction period of at least three years (ratable or cliff vesting). Any options granted under the plan will expire no later than ten years from the date of the grant.

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

Compensation expense related to options granted and restricted stock awarded totaled $6 million, $6 million and $11 million for the years ended December 31, 2011, 2010 and 2009, respectively. We recognize compensation expense ratably over the vesting period of the respective awards. Tax benefits for compensation expense related to options granted and restricted stock awarded totaled $2 million, $2 million and $4 million for the years ended December 31, 2011, 2010 and 2009, respectively. As of December 31, 2011, $10 million of total unrecognized compensation expense related to options granted and restricted stock awarded is expected to be recognized over a weighted-average period of 3.1 years. The total fair value of shares vested was $5 million, $14 million and $12 million for the years ended December 31, 2011, 2010 and 2009, respectively. We did not capitalize or use cash to settle any share-based compensation in the years ended December 31, 2011, 2010 or 2009, other than as described above.

Cash received from option exercises for the years ended December 31, 2011, 2010 and 2009 was $3 million, zero and zero, respectively, and the tax benefit realized for the additional tax deduction from share-based payment awards totaled zero for all years presented. The total intrinsic value of options exercised and released for the years ended December 31, 2011, 2010 and 2009 was $2 million, $2 million, and $1 million, respectively.

In 2010 and 2009, we granted stock-based compensation awards to certain of our employees that cliff vest after three years based partly on the achievement of certain targets for our stock price for February 2012 and 2013, respectively, and partly on the achievement of certain earnings targets. A net compensation expense (benefit) of $(6) million, $5 million and $(1) million was recorded during the years ended December 31, 2011, 2010 and 2009, respectively. The benefits in 2011 and 2009 were due to the change in fair value of our outstanding awards reflecting market conditions. The liability for these awards is accrued in Other long-term liabilities in our consolidated balance sheets.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 24 Capital Stock (Continued)

Stock option activity for the years ended December 31, 2011, 2010 and 2009 was as follows:

	Year Ended December 31,					
	2011		2010		2009	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(options in thousands)					
Outstanding at beginning of period	3,286	$ 23.04	2,808	$ 34.41	1,711	$ 60.12
Granted	3,795	$ 8.04	668	$ 7.20	1,267	$ 5.65
Exercised	(613)	$ 5.65	(11)	$ 5.65	(4)	$ 5.65
Forfeited	(222)	$ 6.68		$	(11)	$ 41.53
Expired	(494)	$ 61.06	(179)	$ 143.12	(155)	$ 83.50
Outstanding at end of period	5,752	$ 12.36	3,286	$ 23.04	2,808	$ 34.41
Vested and unvested expected to vest	5,752	$ 12.36	3,286	$ 23.04	2,808	$ 34.41
Exercisable at end of period	1,751	$ 22.44	1,700	$ 36.92	1,243	$ 61.48

	Year Ended December 31, 2011	
	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at end of period	7.28	$
Vested and unvested expected to vest	7.28	$
Exercisable at end of period	2.39	$

During the three-year period ended December 31, 2011, we did not grant any options at an exercise price less than the market price on the date of grant.

Options outstanding as of December 31, 2011 are summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options Outstanding at December 31, 2011	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number of Options Exercisable at December 31, 2011	Weighted Average Exercise Price
	(options in thousands)				
$4.03 - $5.65	477	5.33	$ 5.48	326	$ 5.65
$6.25	610	9.53	$ 6.25		$
$6.50	825	9.54	$ 6.50		$
$7.20	506	4.11	$ 7.20	401	$ 7.20
$8.00	990	9.54	$ 8.00		$
$8.85	18	1.10	$ 8.85	18	$ 8.85
$10.00	1,320	9.54	$ 10.00		$
$10.35 - $24.40	487	0.72	$ 24.13	487	$ 24.13
$37.40	223	3.21	$ 37.40	223	$ 37.40
$48.35	296	1.56	$ 48.35	296	$ 48.35

	5,752	1,751

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 24 Capital Stock (Continued)

On May 25, 2010, we effected a reverse stock split of our outstanding common stock at a ratio of 1-for-5 and proportionately decreased the number of authorized shares of our capital stock and all prior periods have been adjusted to reflect the reverse stock split.

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

	Year Ended December 31,		
	2011	**2010**	**2009**
Dividends			
Expected volatility (historical)	65.57%	62.45%	61.04%
Risk-free interest rate	2.187%	2.865%	2.834%
Expected option life	6 Years	6 Years	6 Years

The expected volatility was calculated based on a six-year historical volatility of our common stock price for the years ended December 31, 2011, 2010 and 2009, respectively. The risk-free interest rate was calculated based upon observed interest rates appropriate for the term of our employee stock options. Currently, we calculate the expected option life using the simplified methodology suggested by authoritative guidance issued by the SEC. For restricted stock awards, we consider the fair value to be the closing price of the stock on the grant date. We recognize the fair value of our share-based payments over the vesting periods of the awards, which is typically a three-year service period.

The weighted average grant-date fair value of options granted during the years ended December 31, 2011, 2010 and 2009 was $3.36, $4.25 and $3.30, respectively.

Restricted stock activity for the three years ended December 31, 2011 was as follows:

	Year Ended December 31,			
		2011 Weighted Average Grant Date Fair Value		
	2011		**2010**	**2009**
	(restricted stock shares in thousands)			
Outstanding at beginning of period	497	$ 14.62	352	509
Granted		$	378	
Vested	(318)	$ 18.63	(230)	(138)
Forfeited	(93)	$ 7.82	(3)	(19)
Outstanding at end of period	86	$ 7.20	497	352

All restricted stock awards to employees vest immediately upon the occurrence of a change in control in accordance with the terms of the applicable Change in Control Severance Pay Plan.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 25 Employee Compensation, Savings and Pension Plans

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

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

Phantom Stock Plan. In 2011, 2010 and 2009, we issued phantom stock units under our 2009 Phantom Stock Plan. Units awarded under this plan are long term incentive awards that grant the participant the right to receive a cash payment based on the fair market value of our stock on the vesting date of the award. Effective July 8, 2011, stock appreciation rights, which are awards that entitle the holder to a cash payment equal to the difference between the fair market value of a share of stock at the time of exercise and the award's exercise price, also may be awarded under the plan. As these awards must be settled in cash, we account for them as liabilities, with changes in the fair value of the liability recognized as expense in our consolidated statements of operations. Expense recognized in connection with these awards was $4 million, $7 million and $12 million for the years ended December 31, 2011, 2010 and 2009, respectively.

401(k) Savings Plans. For the years ended December 31, 2011, 2010 and 2009, our employees participated in four 401(k) savings plans, all of which meet the requirements of Section 401(k) of the Internal Revenue Code and are defined contribution plans subject to the provisions of ERISA. The following summarizes the plans:

Dynegy Inc. 401(k) Savings Plan. This plan and the related trust fund are established and maintained for the exclusive benefit of participating employees in the United States. Generally, all employees of designated Dynegy subsidiaries are eligible to participate in the plan. Employee pre-tax and Roth contributions to the plan are matched by the company at 100 percent, up to a maximum of five percent of base pay, subject to IRS limitations. Generally, vesting in company contributions is based on years of service with 50 percent vesting per full year of service. The Plan also allows for a discretionary contribution to eligible employee accounts for each plan year, subject to the sole discretion of the Compensation and Human Resources Committee of the Board of Directors. Matching and discretionary contributions, if any, are allocated in the form of units in the Dynegy common stock fund. However, effective as of the first payroll period on or after January 1, 2012, the matching contributions to the plan are being made in cash rather than our Common Stock and are no longer being automatically invested as units in the Dynegy common stock fund. Matching contributions may be invested according to the employee's investment discretion. During the years ended December 31, 2011, 2010 and 2009, we issued approximately 0.6 million, 0.4 million and 0.4 million shares, respectively, of our Class A common stock in the form of matching contributions to fund the plan. No discretionary contributions were made for any of the years in the three-year period ended December 31, 2011.

Dynegy Midwest Generation, LLC 401(K) Savings Plan (formerly the Illinois Power Company Incentive Savings Plan) and Dynegy Midwest Generation, LLC 401(K) Savings Plan for Employees Covered Under a Collective Bargaining Agreement (formerly the Illinois Power Company Incentive

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Savings Plan for Employees Covered Under A Collective Bargaining Agreement). We match 50 percent of employee pre-tax and Roth contributions to the plans, up to a maximum of six percent of base pay, subject to IRS limitations. However, for non-union employees participating in the Dynegy Midwest Generation, LLC 401(k) Savings Plan, benefits were frozen as of December 31, 2011, with all contributions stopping after that date. Effective January 1, 2012, such participants instead became eligible to participate in the Dynegy Inc. 401(k) Savings Plan (assuming all applicable eligibility criteria are met). Employees are immediately 100 percent vested in all contributions. The Plan also provides for an annual discretionary contribution to eligible employee accounts for a plan year, subject to the sole discretion of the Compensation and Human Resources Committee of the Board of Directors. Matching contributions and discretionary contributions, if any, to the plans are initially allocated in the form of units in the Dynegy common stock fund. However, effective as of the first payroll period on or after January 1, 2012, the matching contributions to the plan are being made in cash rather than our Common Stock and are no longer being automatically invested as units in the Dynegy common stock fund. Matching contributions may be invested according to the employee's investment discretion. During the years ended December 31, 2011, 2010 and 2009, we issued 0.2 million, 0.2 million and 0.1 million shares, respectively, of our Class A common stock in the form of matching contributions to the plans. No discretionary contributions were made for any of the years in the three-year period ended December 31, 2011.

Dynegy Northeast Generation, Inc. Savings Incentive Plan. Under this plan we match 50 percent of employee pre-tax contributions up to six percent of base pay for union employees and 50 percent of employee contributions up to eight percent of base pay for non-union employees, in each case subject to IRS limitations. However, for non-union employees participating in the Dynegy Northeast Generation, Inc. Savings Incentive Plan, benefits were frozen as of December 31, 2011, with all contributions stopping after that date. Effective January 1, 2012, such participants instead became eligible to participate in the Dynegy Inc. 401(k) Savings Plan (assuming all applicable eligibility criteria are met). Employees are immediately 100 percent vested in our contributions. Matching contributions to this plan are made in cash and invested according to the employee's investment discretion.

During the years ended December 31, 2011, 2010 and 2009, we recognized aggregate costs related to these employee compensation plans of $4 million, $5 million and $5 million, respectively.

Pension and Other Post-Retirement Benefits

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

Restoration Plans. In 2008, we adopted the Dynegy Inc. Restoration 401(k) Savings Plan, or the Restoration 401(k) Plan, and the Dynegy Inc. Restoration Pension Plan, or the Restoration Pension Plan, two nonqualified plans that supplement or restore benefits lost by certain of our highly compensated employees under the qualified plans as a result of Internal Revenue Code limitations that apply to the qualified plans. The Restoration 401(k) Plan is intended to supplement benefits under

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 25 Employee Compensation, Savings and Pension Plans (Continued)

certain of the 401(k) plans, and the Restoration Pension Plan is intended to supplement benefits under certain of the pension plans. Employees who are eligible employees under the related qualified plans and earn in excess of certain of the qualified plan limits are eligible to participate in the restoration plans. The definitions of plan pay under the restoration plans, as well as the vesting rules, mirror those under the related qualified plans. Benefits under the restoration plans are paid as a lump sum. However, effective for periods on and after January 1, 2012, participation in and benefit accruals under these plans were frozen.

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

	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(in millions)			
Projected benefit obligation, beginning of the year	$ 272	$ 242	$ 69	$ 65
Service cost	12	11	3	3
Interest cost	14	14	4	4
Actuarial (gain) loss	14	13	7	(1)
Benefits paid	(12)	(8)	(2)	(2)
Plan change	(9)			
Curtailment gain			(19)	
Deconsolidation of DH	(1)		(19)	
Projected benefit obligation, end of the year	$ 290	$ 272	$ 43	$ 69
Fair value of plan assets, beginning of the year	$ 221	$ 186	$	$
Actual return on plan assets	14	25		
Employer contributions	13	18	2	2
Benefits paid	(12)	(8)	(2)	(2)
Deconsolidation of DH	(1)			
Fair value of plan assets, end of the year	$ 235	$ 221	$	$
Funded status	$ (55)	$ (51)	$ (43)	$ (69)

The accumulated benefit obligation for all defined benefit pension plans was $274 million and $243 million at December 31, 2011 and 2010, respectively. The following summarizes information for our defined benefit pension plans, all of which have an accumulated benefit obligation in excess of plan assets at December 31, 2011:

	December 31,	
	2011	2010
	(in millions)	
Projected benefit obligation	$ 290	$ 272
Accumulated benefit obligation	274	243
Fair value of plan assets	235	221

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 25 Employee Compensation, Savings and Pension Plans (Continued)

Pre-tax amounts recognized in Accumulated other comprehensive loss consist of:

	Year Ended December 31,			
	2011		2010	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
	(in millions)			
Prior service cost	$ (6)	$ (1)	$ 4	$ (1)
Actuarial loss	92	1	80	9
Net losses recognized	$ 86	$	$ 84	$ 8

Amounts recognized in the consolidated balance sheets consist of:

	Year Ended December 31,			
	2011		2010	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
	(in millions)			
Current liabilities	$	$ (1)	$	$ (2)
Noncurrent liabilities	(56)	(41)	(51)	(67)
Net amount recognized	$ (56)	$ (42)	$ (51)	$ (69)

The estimated net actuarial loss and prior service cost that will be amortized from Accumulated other comprehensive loss into net periodic benefit cost during the year ended December 31, 2012 for the defined benefit pension plans are $6 million and less than $1 million, respectively. The estimated net actuarial loss and prior service cost that will be amortized from Accumulated other comprehensive loss into net periodic benefit cost during the year ended December 31, 2012 for other postretirement benefit plans are both zero. The amortization of prior service cost is determined using a straight line amortization of the cost over the average remaining service period of employees expected to receive benefits under the Plan.

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

	Pension Benefits			Other Benefits		
	2011	2010	2009	2011	2010	2009
	(in millions)					
Service cost benefits earned during period	$ 12	$ 11	$ 12	$ 3	$ 3	$ 3
Interest cost on projected benefit obligation	14	14	13	4	4	3
Expected return on plan assets	(17)	(16)	(14)			
Amortization of prior service costs	1					
Recognized net actuarial loss	5	5	4			1
Curtailment gain				(4)		
Total net periodic benefit cost	$ 15	$ 14	$ 15	$ 3	$ 7	$ 7

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 25 Employee Compensation, Savings and Pension Plans (Continued)

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

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2011	2010	2011	2010
Discount rate(1)	4.80%	5.49%	4.93%	5.61%
Rate of compensation increase	2.00% - 4.00%	4.00% - 5.00%	N/A	4.50%

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

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

	Pension Benefits			Other Benefits		
	Year Ended December 31,			Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
Discount rate	5.49%	5.86%	6.12%	5.61%	5.92%	5.93%
Expected return on plan assets	8.00%	8.00%	8.25%	N/A	N/A	N/A
Rate of compensation increase	3.00% - 4.00%	2.50% - 3.50%	3.00% - 4.50%	N/A	4.50%	4.50%

Our expected long-term rate of return on plan assets for the year ended December 31, 2012 will be 7 percent. This figure begins with a blend of asset class-level returns developed under a theoretical global capital asset pricing model methodology conducted by an outside consultant. In development of this figure, the historical relationships between equities and fixed income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long-term. Current market factors such as inflation and interest rates are also incorporated in the assumptions. This figure gives consideration towards the plan's use of active management and favorable past experience. It is also net of plan expenses.

The following summarizes our assumed health care cost trend rates:

	December 31,	
	2011	2010
Health care cost trend rate assumed for next year	8.00%	8.00%
Ultimate trend rate	4.50%	5.00%
Year that the rate reaches the ultimate trend rate	2019	2016

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 25 Employee Compensation, Savings and Pension Plans (Continued)

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

	Increase	Decrease
	(in millions)	
Aggregate impact on service cost and interest cost	$ 1	$ (1)
Impact on accumulated post-retirement benefit obligation	$ 7	$ (6)

Plan Assets. We employ a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. The intent of this strategy is to minimize plan expenses by outperforming plan liabilities over the long run. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks as well as growth, value, and small and large capitalizations. The target allocations for plan assets are thirty-five percent fixed income securities, forty percent U.S. equity securities, five percent non-U.S. equity securities, and twenty percent global equity securities.

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

The following table sets forth by level within the fair value hierarchy assets that were accounted for at fair value related to our pension plans. These assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
		(in millions)		
Equity securities:				
U.S. companies (1)	$	$ 97	$	$ 97
Non-U.S. companies (2)		10		10
International (3)		44		44
Fixed income securities (4)	43	41		84
Total	$ 43	$ 192	$	$ 235

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

(2) This category comprises a common collective trust not actively managed that tracks the MSCI All Country World Ex-U.S. Index.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 25 Employee Compensation, Savings and Pension Plans (Continued)

(3) This category comprises actively managed common collective trusts that hold U.S. and foreign equities. These trusts track the MSCI World Index.

(4) This category includes a mutual fund and a trust that invest primarily in investment grade corporate bonds.

Contributions and Payments. During the year ended December 31, 2011, we contributed approximately $12 million to our pension plans and $2 million to our other post-retirement benefit plans. In 2012, we expect to contribute approximately $20 million to our pension plans and zero to our other postretirement benefit plans.

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

	Pension Benefits	Other Benefits
	(in millions)	
2012	$ 14	$ 1
2013	14	1
2014	13	2
2015	13	2
2016	14	2
2017 - 2021	90	12

Note 26 Segment Information

As reflected in this report, we have changed our reportable segments. Prior to this report, we reported results for the following segments: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. Beginning with the third quarter 2011, as a result of the Reorganization, our reportable segments are: (i) Coal, (ii) Gas and (iii) DNE. Accordingly, we have recast the corresponding items of segment information for all prior periods. Our consolidated financial results also reflect corporate-level expenses such as interest and depreciation and amortization. General and administrative expenses are allocated to each reportable segment. Additionally, effective November 7, 2011, DH, including our Gas and DNE segments, was deconsolidated and we began accounting for our investment in DH using the equity method of accounting.

During 2011, one customer in Coal, one customer in Gas and one customer in DNE accounted for approximately 41 percent, 20 percent and 16 percent of our consolidated revenues, respectively. During 2010, one customer in Coal, one customer in Gas and one customer related to both DNE and Gas accounted for approximately 30 percent, 13 percent and 15 percent of our consolidated revenues, respectively. During 2009, one customer in Coal, one customer in Gas and one customer related to both DNE and Gas accounted for approximately 19 percent, 11 percent and 12 percent of our consolidated revenues, respectively.

Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the years ended December 31, 2011, 2010 and 2009 is presented below.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 26 Segment Information (Continued)

Segment Data as of and for the Year Ended December 31, 2011

(in millions)

	Coal	Gas	DNE	Other and Eliminations	Total
Total revenues	$ 658	$ 828	$ 101	$ (2)	$ 1,585
Depreciation and amortization	$ (206)	$ (114)	$	$ (5)	$ (325)
Impairment and other charges			(2)	(4)	(6)
General and administrative expense	(45)	(49)	(9)	(32)	(135)
Operating loss	$ (101)	$ (19)	$ (70)	$ (46)	$ (236)
Loss on deconsolidation				(1,657)	(1,657)
Other items, net	1	1		(8)	(6)
Interest expense					(357)
Debt extinguishment costs					(21)
Loss from continuing operations before income taxes					(2,277)
Income tax benefit					632
Net loss					$ (1,645)
Identifiable assets (domestic)	$ 4,079	$	$	$ 48	$ 4,127
Capital expenditures	$ (184)	$ (57)	$ (1)	$	$ (242)

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 26 Segment Information (Continued)

Segment Data as of and for the Year Ended December 31, 2010

(in millions)

	Coal	Gas	DNE	Other and Eliminations	Total
Total revenues	$ 836	$ 1,223	$ 264	$	$ 2,323
Depreciation and amortization	$ (256)	$ (135)	$ 5	$ (6)	$ (392)
Impairment and other charges	(4)	(136)	(2)	(6)	(148)
General and administrative expense	(52)	(69)	(15)	(27)	(163)
Operating income (loss)	$ (6)	$ 23	$ 11	$ (39)	$ (11)
Losses from unconsolidated investments				(62)	(62)
Other items, net		2		2	4
Interest expense					(363)
Loss from continuing operations before income taxes					(432)
Income tax benefit					197
Loss from continuing operations					$ (235)
Income from discontinued operations, net of income taxes					1
Net loss					$ (234)
Identifiable assets (domestic)	$ 4,375	$ 3,655	$ 549	$ 1,434	$ 10,013
Capital expenditures and investments in unconsolidated affiliates	$ (274)	$ (50)	$ (3)	$ (21)	$ (348)

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 26 Segment Information (Continued)

Segment Data as of and for the Year Ended December 31, 2009

(in millions)

	Coal	Gas	DNE	Other and Eliminations	Total
Total revenues	$ 940	$ 1,260	$ 273	$ (5)	$ 2,468
Depreciation and amortization	$ (161)	$ (148)	$ (8)	$ (18)	$ (335)
Goodwill impairments		(433)			(433)
Impairment and other charges	(42)	(284)	(212)		(538)
General and administrative expense	(49)	(96)	(13)	(1)	(159)
Operating income (loss)	$ 155	$ (752)	$ (217)	$ (20)	$ (834)
Losses from unconsolidated investments				(71)	(71)
Other items, net	2	2		7	11
Interest expense and debt extinguishment costs					(461)
Loss from continuing operations before income taxes					(1,355)
Income tax benefit					315
Loss from continuing operations					$ (1,040)
Loss from discontinued operations, net of income taxes					(222)
Net loss					$ (1,262)
Less: Net loss attributable to the noncontrolling interest					(15)
Net loss attributable to Dynegy Inc.					$ (1,247)
Identifiable assets ($24 million foreign)	$ 4,333	$ 3,875	$ 493	$ 2,252	$ 10,953
Capital expenditures	$ (398)	$ (91)	$ (8)	$ (115)	$ (612)

Note 27 Quarterly Financial Information (Unaudited)

The following is a summary of our unaudited quarterly financial information for the years ended December 31, 2011 and 2010:

	Quarter Ended			
	March 2011	June 2011	September 2011	December 2011
	(in millions, except per share data)			
Revenues	$ 505	$ 326	$ 516	$ 238
Operating income (loss)	(49)	(106)	5(1)	(86)
Net income (loss)	(77)	(116)	(75)(1)	(1,377)(2)
Net income (loss) per share	$ (0.64)	$ (0.95)	$ (0.61)(1)	$ (11.29)(2)

(1) Includes debt extinguishment costs of $21 million incurred in connection with the termination of the Sithe Senior Notes. Please read Note 19 Debt DH Debt Obligations Sithe Senior Notes for further discussion.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 27 Quarterly Financial Information (Unaudited) (Continued)

(2)
Includes a loss of $1,657 million related to the deconsolidation of DH. Please read Note 3 Chapter 11 Cases for further discussion.

	Quarter Ended			
	March 2010	June 2010	September 2010	December 2010
	(in millions, except per share data)			
Revenues	$ 858	$ 239	$ 775	$ 451
Operating income (loss)	331	(229)	50(2)	(163)
Net income (loss)	145(1)	(191)	(24)(2)	(164)(3)
Net income (loss) per share	$ 1.21(1)	$ (1.59)	$ (0.20)(2)	$ (1.36)(3)

(1)
Includes $37 million of impairment charges related to our equity investment in PPEA Holding, which is included in Earnings (losses) from unconsolidated investments.

(2)
Includes impairment charges of $134 million related to our Casco Bay facility and related assets. Please read Note 8 Impairment and Restructuring Charges for further discussion.

(3)
Includes a pre-tax charge of $28 million related to the sale of PPEA Holdings. This charge is included in Earnings (losses) from unconsolidated investments. Please read Note 16 Variable Interest Entities PPEA Holding Company LLC for further discussion.

Schedule I

DYNEGY INC.

CONDENSED BALANCE SHEETS OF THE REGISTRANT

(in millions)

	December 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	$ 37	$ 38
Accounts receivable		1
Accounts receivable affiliate	4	
Intercompany accounts receivable	77	
Short term investments		16
Deferred income taxes	5	12
Prepayments and other current assets	2	
Total Current Assets	125	67
Other Assets		
Investments in affiliates	5,481	6,208
Total Assets	$ 5,606	$ 6,275
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Other current liabilities	20	2
Total Current Liabilities	20	2
Undertaking payable affiliate	1,250	
Intercompany long-term debt	2,243	2,243
Deferred income taxes	5	641
Other long-term liabilities	97	
Other long-term liabilities affiliates	879	643
Total Liabilities	4,494	3,529
Commitments and Contingencies (Note 2)		
Stockholders' Equity		
Class A Common Stock, $0.01 par value, 420,000,000 shares authorized at December 31, 2011 and December 31, 2010, respectively	1	1
Additional paid-in capital	6,077	6,067
Subscriptions receivable	(2)	(2)
Accumulated other comprehensive loss, net of tax	(53)	(53)
Accumulated deficit	(4,841)	(3,196)
Treasury stock, at cost, 731,407 shares and 628,014 shares at December 31, 2010 and December 31, 2009, respectively	(70)	(71)
Total Stockholders' Equity	1,112	2,746

Total Liabilities and Stockholders' Equity	$	5,606	$	6,275

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

Schedule I

DYNEGY INC.

CONDENSED STATEMENTS OF OPERATIONS OF THE REGISTRANT

(in millions)

	Year Ended December 31,		
	2011	2010	2009
Operating loss	$ (22)	$ (5)	$
Loss on deconsolidation of DH	(1,657)		
Losses from unconsolidated investments	(598)	(426)	(1,684)
Other income and expense, net			1
Loss before income taxes	(2,277)	(431)	(1,683)
Income tax benefit	632	197	436
Net loss	$ (1,645)	$ (234)	$ (1,247)

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

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Schedule I

DYNEGY INC.

CONDENSED STATEMENTS OF CASH FLOWS OF THE REGISTRANT

(in millions)

	Year Ended December 31, 2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Operating cash flow, exclusive of intercompany transactions	$ (5)	$ (4)	$ (19)
Intercompany transactions	(13)	5	3
Net cash provided by (used in) operating activities	(18)	1	(16)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Unconsolidated investments			1
Short term investments	16	(15)	
Net cash provided by (used in) investing activities	16	(15)	1
CASH FLOWS FROM FINANCING ACTIVITIES:			
Dividends from affiliate			585
Redemption of capital stock			(540)
Proceeds from issuance of capital stock	1		
Net cash provided by financing activities	1		45
Net increase (decrease) in cash and cash equivalents	(1)	(14)	30
Cash and cash equivalents, beginning of period	38	52	22
Cash and cash equivalents, end of period	$ 37	$ 38	$ 52
SUPPLEMENTAL CASH FLOW INFORMATION			
Taxes paid (net of refunds)	(2)	7	4
SUPPLEMENTAL NONCASH FLOW INFORMATION			
Undertaking payable to DH	1,250		
Shares acquired through exchange of DH assets			97
Contribution of intangibles and related deferred income taxes to DH			36
Other affiliate activity	61	(37)	(48)

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

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Schedule I

DYNEGY INC.

NOTES TO REGISTRANT'S FINANCIAL STATEMENTS

Note 1 Background and Basis of Presentation

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

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

Note 2 Commitments and Contingencies

For a discussion of our commitments and contingencies, please read Note 23 Commitments and Contingencies of our consolidated financial statements.

Please read Note 19 Debt of our consolidated financial statements and Note 23 Commitments and Contingencies Guarantees and Indemnifications of our consolidated financial statements for a discussion of our guarantees.

Note 3 Related Party Transactions

For a discussion of our related party transactions, please read Note 20 Related Party Transactions of our consolidated financial statements.

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Schedule II

DYNEGY INC.

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2011, 2010 and 2009

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Additions/ (Deductions)	DH Deconsolidation(3)	Balance at End of Period
	(in millions)					
2011						
Allowance for doubtful accounts	$ 32	$	$	$ (1)	$ (12)	$ 19
Impairment of loan receivable from affiliate(1)		10				10
Deferred tax asset valuation allowance	22	1,235				1,257
2010						
Allowance for doubtful accounts(2)	$ 22	$	$	$ 10	$	$ 32
Deferred tax asset valuation allowance	35	(1)	(12)			22
2009						
Allowance for doubtful accounts	$ 22	$	$	$	$	$ 22
Deferred tax asset valuation allowance	37	12	(14)			35

(1) The impairment of loan receivable from affiliate increase by $10 million in connection with an August 2011 affiliate note between Coal HoldCo and DH. In connection with DH's bankruptcy filing, we determined it was probable that Coal HoldCo would not collect any amounts due associated with the note and the note was fully impai