DYNEGY INC.
Form 10-K
March 08, 2012

Table of Contents

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.

DYNEGY INC.
FORM 10-K
TABLE OF CONTENTS

Table of Contents

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

Table of Contents

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

Table of Contents

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

Table of Contents

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.

Table of Contents

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*				

(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.

Table of Contents

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

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

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

12

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

Table of Contents

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

Table of Contents

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

Table of Contents

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

Table of Contents

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

Table of Contents

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

Table of Contents

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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

Table of Contents

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

Table of Contents

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

Table of Contents

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,

Table of Contents

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

Table of Contents

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.

Table of Contents

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;

31

- 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

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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;

- 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.

38

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,

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

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.

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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)

Table of Contents

	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).

Table of Contents

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

Table of Contents

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;

Table of Contents

- 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.

Table of Contents

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

Table of Contents

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,

Table of Contents

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

Table of Contents

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

Table of Contents

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.

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 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.

Table of Contents

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.

Table of Contents

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,

Table of Contents

$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.

Table of Contents

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

Table of Contents

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.

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
		Expiration by Period (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

Table of Contents

because we believe it is meaningful to investors. 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)		
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 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

Table of Contents

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.

Table of Contents

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

Table of Contents

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)%

Table of Contents

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)

Table of Contents

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

(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)

Table of Contents

	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.

Table of Contents

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.

Table of Contents

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 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

Table of Contents

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)				