DYNEGY INC.
Form 10-Q
August 07, 2014
Table of Contents

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

FORM 10-Q

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

For the quarterly period ended June 30, 2014

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

For the transition period from ________ to ________

Commission file number: 001-33443

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

State of Incorporation	I.R.S. Employer Identification No.
Delaware	20-5653152
601 Travis, Suite 1400 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

Large accelerated filer ý	Accelerated filer o
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 ¨ No x

Indicate by check mark whether the registrant filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes x No ¨

Table of Contents

Indicate the number of shares outstanding of our class of common stock, as of the latest practicable date: Common stock, $0.01 par value per share, 100,365,160 shares outstanding as of August 1, 2014.

TABLE OF CONTENTS

Table of Contents

DEFINITIONS

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

AER	New Ameren Energy Resources, LLC
Ameren	Ameren Corporation
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BACT	Best Available Control Technology
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	The California Independent System Operator
CARB	California Air Resources Board
CCA	California Carbon Allowances
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CO_2	Carbon Dioxide
CPUC	California Public Utility Commission
CSAPR	Cross-State Air Pollution Rule
DH	Dynegy Holdings, LLC (formerly known as Dynegy Holdings Inc.)
DMG	Dynegy Midwest Generation, LLC
DNE	Dynegy Northeast Generation, Inc.
DPC	Dynegy Power, LLC
DYPM	Dynegy Power Marketing, LLC
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EEI	Electric Energy, Inc.
EGU	Electric Generating Units
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles of the United States of America
GHG	Greenhouse Gas
GW	Gigawatts
HAPs	Hazardous Air Pollutants, as defined by the Clean Air Act
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
IGC	Illinova Generating Company
IGCC	Integrated Gasification Combined Cycle
IMA	In-market Asset Availability
IPCB	Illinois Pollution Control Board
IPGC or Genco	Illinois Power Generating Company (formerly known as Ameren Energy Generating Company)
IPH	Illinois Power Holdings, LLC

Table of Contents

IPM	Illinois Power Marketing Company (formerly known as Ameren Energy Marketing Company)
IPR	Illinois Power Resources, LLC (formerly known as New Ameren Energy Resources, LLC)
IPRG	Illinois Power Resources Generating, LLC (formerly known as New AERG, LLC)
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LC	Letter of Credit
LGE	Louisville Gas and Electric Company
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Pricing
LPG	Liquefied Petroleum Gas
LSE	Load Serving Entity
MATS	Mercury and Air Toxic Standards
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	One Million British Thermal Units
MPS	Multi-Pollutant Standards
Moody’s	Moody’s Investors Service Inc.
MW	Megawatts
MWh	Megawatt Hour
NOL	Net Operating Loss
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
NYISO	New York Independent System Operator
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PPE	Ponderosa Pine Energy, LLC
PRIDE	Producing Results through Innovation by Dynegy Employees
PSD	Prevention of Significant Deterioration
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPM	Reliability Pricing Model
S&P	Standard & Poor’s Ratings Services
SCE	Southern California Edison
SEC	U.S. Securities and Exchange Commission
SO2	Sulfur Dioxide
TVA	Tennessee Valley Authority
VaR	Value at Risk

Table of Contents

PART I. FINANCIAL INFORMATION
Item 1—FINANCIAL STATEMENTS
DYNEGY INC.
CONSOLIDATED BALANCE SHEETS
(unaudited) (in millions, except share data)

	June 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$948	$843
Accounts receivable, net of allowance for doubtful accounts of $2 and zero, respectively	367	420
Inventory	206	181
Assets from risk management activities	10	25
Intangible assets	60	108
Prepayments and other current assets	108	108
Total Current Assets	1,699	1,685
Property, Plant and Equipment	3,586	3,527
Accumulated depreciation	(326)	(212)
Property, Plant and Equipment, Net	3,260	3,315
Other Assets		
Assets from risk management activities	11	11
Intangible assets	50	68
Deferred income taxes	65	100
Other long-term assets	103	112
Total Assets	$5,188	$5,291

See the notes to consolidated financial statements.

Table of Contents

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

	June 30, 2014	December 31, 2013
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$305	$329
Accrued interest	13	13
Deferred income taxes	65	100
Intangible liabilities	57	62
Accrued liabilities and other current liabilities	166	139
Liabilities from risk management activities	110	65
Debt, current portion	37	13
Total Current Liabilities	753	721
Debt, long-term portion	1,971	1,979
Other Liabilities		
Liabilities from risk management activities	40	33
Asset retirement obligations	160	173
Other long-term liabilities	212	178
Total Liabilities	3,136	3,084
Commitments and Contingencies (Note 10)		
Stockholders' Equity		
Common stock, $0.01 par value, 420,000,000 shares authorized at June 30, 2014 and December 31, 2013; 100,363,958 shares and 100,202,036 shares issued and outstanding at June 30, 2014 and December 31, 2013, respectively	1	1
Additional paid-in capital	2,623	2,614
Accumulated other comprehensive income, net of tax	54	58
Accumulated deficit	(627)	(463)
Total Dynegy Stockholders' Equity	2,051	2,210
Noncontrolling interest	1	(3)
Total Equity	2,052	2,207
Total Liabilities and Equity	$5,188	$5,291

See the notes to consolidated financial statements.

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$521	$301	$1,283	$619
Cost of sales, excluding depreciation expense	(365)	(253)	(917)	(537)
Gross margin	156	48	366	82
Operating and maintenance expense	(136)	(85)	(246)	(156)
Depreciation expense	(57)	(49)	(124)	(103)
Gain on sale of assets, net	14	1	14	2
General and administrative expense	(29)	(25)	(55)	(47)
Acquisition and integration costs	(2)	(1)	(8)	(4)
Operating loss	(54)	(111)	(53)	(226)
Earnings from unconsolidated investments	10	—	10	—
Interest expense	(42)	(16)	(72)	(45)
Loss on extinguishment of debt	—	(12)	—	(11)
Other income and expense, net	(39)	(11)	(45)	(10)
Loss from continuing operations before income taxes	(125)	(150)	(160)	(292)
Income tax benefit	3	—	1	—
Loss from continuing operations	(122)	(150)	(159)	(292)
Income from discontinued operations, net of tax (Note 3)	—	5	—	5
Net loss	(122)	(145)	(159)	(287)
Less: Net income attributable to noncontrolling interest	1	—	5	—
Net loss attributable to Dynegy Inc.	$(123)	$(145)	$(164)	$(287)
Loss Per Share (Note 14):				
Basic loss per share attributable to Dynegy Inc.:				
Loss from continuing operations	$(1.23)	$(1.50)	$(1.64)	$(2.92)
Income from discontinued operations	—	0.05	—	0.05
Basic loss per share attributable to Dynegy Inc.	$(1.23)	$(1.45)	$(1.64)	$(2.87)
Diluted loss per share attributable to Dynegy Inc.:				
Loss from continuing operations	$(1.23)	$(1.50)	$(1.64)	$(2.92)
Income from discontinued operations	—	0.05	—	0.05
Diluted loss per share attributable to Dynegy Inc.	$(1.23)	$(1.45)	$(1.64)	$(2.87)
Basic shares outstanding	100	100	100	100
Diluted shares outstanding	101	100	101	100

See the notes to consolidated financial statements.

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net loss	$(122)	$(145)	$(159)	$(287)
Other comprehensive loss before reclassifications:				
Actuarial loss (net of tax of zero, zero, zero and zero, respectively)	—	—	(3)	—
Amounts reclassified from accumulated other comprehensive income (loss):				
Reclassification of curtailment gain included in net loss (net of tax of zero, zero, zero and zero, respectively)	—	(7)	—	(7)
Amortization of unrecognized prior service cost and actuarial loss (net of tax of zero, zero, zero and zero, respectively)	(1)	—	(2)	—
Other comprehensive loss, net of tax	(1)	(7)	(5)	(7)
Comprehensive loss	(123)	(152)	(164)	(294)
Less: Comprehensive income attributable to noncontrolling interest	1	—	4	—
Total comprehensive loss attributable to Dynegy Inc.	$(124)	$(152)	$(168)	$(294)

See the notes to consolidated financial statements.

Table of Contents

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

	Six Months Ended June 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(159)	$(287)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation expense	124	103
Loss on extinguishment of debt	—	11
Non-cash interest expense (benefit)	10	(3)
Amortization of intangibles	35	127
Risk management activities	71	34
Gain on sale of assets, net	(14)	(2)
Deferred income taxes	(1)	—
Change in value of common stock warrants	49	9
Other	19	5
Changes in working capital:		
Accounts receivable, net	63	3
Inventory	(18)	25
Prepayments and other current assets	14	(3)
Accounts payable and accrued liabilities	(28)	(21)
Affiliate transactions	—	(1)
Changes in non-current assets	(6)	(5)
Changes in non-current liabilities	4	(5)
Net cash provided by (used in) operating activities	163	(10)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(69)	(55)
Proceeds from asset sales, net	14	3
Decrease in restricted cash	—	335
Net cash provided by (used) in investing activities	(55)	283
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of financing costs	11	1,753
Repayments of borrowings, including debt extinguishment costs	(4)	(1,913)
Interest rate swap settlement payments	(9)	—
Other financing	(1)	—
Net cash used in financing activities	(3)	(160)
Net increase in cash and cash equivalents	105	113
Cash and cash equivalents, beginning of period	843	348
Cash and cash equivalents, end of period	$948	$461

See the notes to consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Note 1—Basis of Presentation and Organization

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to interim financial reporting as prescribed by the SEC. The year-end consolidated balance sheet data was derived from audited consolidated financial statements but does not include all disclosures required by GAAP. The unaudited consolidated financial statements contained in this report include all material adjustments of a normal recurring nature that, in the opinion of management, are necessary for a fair presentation of the results for the interim periods. Certain prior period amounts in our consolidated financial statements have been reclassified to conform to current year presentation. These interim financial statements should be read together with the consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 27, 2014, which we refer to as our "Form 10-K." Unless the context indicates otherwise, throughout this report, the terms "Dynegy," "the Company," "we," "us," "our," and "ours" are used to refer to Dynegy Inc. and direct and indirect 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 unaudited consolidated financial statements: (i) the Coal segment ("Coal"), (ii) the IPH segment ("IPH") and (iii) the Gas segment ("Gas"). Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). Please read Note 16—Segment Information for further discussion. All significant intercompany transactions have been eliminated.

Illinois Power Holdings, LLC ("IPH") and its direct and indirect subsidiaries are organized into ring-fenced groups in order to maintain corporate separateness from Dynegy and its other subsidiaries. Certain of the entities in the IPH segment, including Illinois Power Generating Company ("IPGC" or "Genco"), have an independent director whose consent is required for certain corporate actions, including material transactions with affiliates. Further, entities within the IPH segment present themselves to the public as separate entities. They maintain separate books, records and bank accounts and separately appoint officers. Furthermore, they pay liabilities from their own funds, conduct business in their own names and have restrictions on pledging their assets for the benefit of certain other persons. These provisions restrict our ability to move cash out of these entities without meeting certain requirements as set forth in the governing documents.

Note 2—Accounting Policies

The accounting policies followed by the Company are set forth in Note 2—Summary of Significant Accounting Policies of the Notes to Consolidated Financial Statements in our Form 10-K. There have been no significant changes to these policies during the six months ended June 30, 2014.

The preparation of consolidated financial statements in conformity with GAAP requires management to make informed estimates and judgments that affect our reported financial position and results of operations based on currently available information. Actual results could differ materially from our estimates. The results of operations for the interim periods presented in this Form 10-Q are not necessarily indicative of the results to be expected for the full year or any other interim period due to seasonal fluctuations in demand for our energy products and services, changes in commodity prices, timing of maintenance and other expenditures and other factors.

Accounting Standards Adopted During the Current Period

Presentation of Unrecognized Tax Benefits. In July 2013, the FASB issued ASU 2013-11-Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. The provisions of the rule require an unrecognized tax benefit to be presented as a reduction to a deferred tax asset in the financial statements for an NOL carryforward, a similar tax loss, or a tax credit carryforward except in circumstances when the carryforward or tax loss is not available at the reporting date under the tax laws of the applicable jurisdiction to settle any additional income taxes or the tax law does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purposes. When those circumstances exist, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The new financial statement presentation provisions relating to this ASU are prospective and effective for interim and annual periods beginning after December 15, 2013. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Joint and Several Liability Arrangements. In February 2013, the FASB issued ASU 2013-04-Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date. The provisions of the rule require an entity to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, as the sum of (i) the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and (ii) any additional amount the reporting entity expects to pay on behalf of its co-obligors. The guidance in this ASU also requires an entity to disclose the nature and amount of the obligation as well as other information about those obligations. ASU 2013-04 is effective for interim and annual periods beginning after December 15, 2013. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting Standards Not Yet Adopted

Reporting Discontinued Operations and Asset Disposals. In April 2014, the FASB issued ASU 2014-08-Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosure of Disposals of Components of an Entity. The amendments in this ASU change the requirements for reporting discontinued operations in Subtopic 205-20. An entity is required to report within discontinued operations on the statement of operations the results of a component or group of components of an entity if the disposal represents a strategic shift that has, or will have, a major effect on an entity's operations and financial results. Additionally, the associated assets and liabilities are required to be presented separately from other assets and liabilities on the balance sheet for all comparative periods. The ASU includes updated guidance regarding what meets the definition of a component of an entity. The new financial statement presentation provisions relating to this ASU are prospective and effective for interim and annual periods beginning after December 15, 2014, with early adoption permitted. We do not anticipate the adoption of this ASU having a material impact on our consolidated financial statements.

Revenue from Contracts with Customers. In May 2014, the FASB and IASB jointly issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). The amendments in this ASU develop a common revenue standard for U.S. GAAP and IFRS by removing inconsistencies and weaknesses in revenue requirements, providing a more robust framework for addressing revenue issues, improving comparability of revenue recognition practices, providing more useful information to users of financial statements and simplifying the preparation of financial statements. The guidance in this ASU is effective for interim and annual periods beginning after December 15, 2016. We are currently assessing this ASU; however, we do not anticipate a material impact on our consolidated financial statements.

Note 3—Acquisition and Divestitures

Acquisition

AER Transaction Agreement. On December 2, 2013, pursuant to the terms of the definitive agreement dated as of March 14, 2013 and as amended on December 2, 2013 (the "AER Transaction Agreement") by and between Illinois Power Holdings, LLC ("IPH"), an indirect wholly-owned subsidiary of Dynegy, and Ameren Corporation ("Ameren"), IPH completed its acquisition from Ameren of 100 percent of the equity interests of New Ameren Energy Resources, LLC ("AER") and its subsidiaries (the "AER Acquisition"). The acquisition added 4,062 MW of generation in Illinois and also included the Homefield Energy retail business. There was no cash consideration or stock issued as part of the purchase price. We acquired AER and its subsidiaries through IPH which maintains corporate separateness from our legal entities outside of IPH.

In connection with the AER Acquisition, Ameren retained certain historical obligations of Illinois Power Resources, LLC ("IPR") and its subsidiaries, including certain historical environmental and tax liabilities. Approximately $825 million in aggregate principal amount of Genco notes remained outstanding as an obligation of Genco. Additionally, Ameren is required to maintain its existing credit support, including all of its collateral obligations with respect to Illinois Power Marketing Company ("IPM"), for a period not to exceed two years following closing. Dynegy has provided a limited guaranty of certain obligations of IPH up to $25 million (the "Limited Guaranty") as further described in Note 10—Commitments and Contingencies—Guarantees.

We incurred costs of $2 million and $8 million for the three and six months ended June 30, 2014, respectively, and $1 million and $4 million for the three and six months ended June 30, 2013, respectively. These costs were included in Acquisition and integration costs in our unaudited consolidated statements of operations. Revenues of $179 million and $383 million, respectively, and net loss of $14 million and $72 million attributable to IPH are included in our unaudited consolidated statements of operations for the three and six months ended June 30, 2014, respectively.

As noted in Note 3—Merger and Acquisitions in our Form 10-K, Dynegy recorded the assets acquired and liabilities assumed as part of the AER Transaction Agreement at their estimated fair values on the acquisition date. These assets and liabilities were recorded at provisional fair values. As of June 30, 2014, we completed our valuations which resulted in immaterial changes to the provisional fair values.

Pro Forma Results. The unaudited pro forma financial results for the six months ended June 30, 2013 assume the AER Acquisition had occurred on January 1, 2013. The unaudited pro forma financial results may not be indicative of the results that would have occurred had the acquisition been completed as of January 1, 2013, nor are they indicative of future results of operations.

(amounts in millions)	Six Months Ended June 30, 2013
Revenues	$1,196
Net loss	$(321)
Net loss attributable to noncontrolling interest	$(2)
Net loss attributable to Dynegy Inc.	$(319)

Divestiture

Black Mountain. On June 27, 2014, we completed the sale of our 50 percent partnership interest in Nevada Cogeneration Associates #2, a partnership that owns Black Mountain, an 85 MW (43 net MW) natural gas-fired combined cycle gas turbine facility in Nevada. We received $14 million in cash proceeds upon the close of the transaction, which is reflected in Gain on sale of assets, net in our unaudited consolidated statements of operations for the three and six months ended June 30, 2014. In connection with the sale, our guarantee was terminated. Additionally, we received $10 million in cash distributions from Black Mountain, which is recorded as Earnings from unconsolidated investments in our unaudited consolidated statements of operations for the three and six months ended June 30, 2014.

Discontinued Operations

On April 30, 2013, we completed the sale of Dynegy Roseton, L.L.C. (“Roseton”). On November 1, 2013, the Dynegy Danskammer, L.L.C. (“Danskammer”) assets were sold. Any activity related to our Roseton and Danskammer operations is included in Income from discontinued operations, net of tax in our unaudited consolidated statements of operations for the three and six months ended June 30, 2013.

Note 4—Risk Management Activities, Derivatives and Financial Instruments

The nature of our business necessarily involves market and financial risks. Specifically, we are exposed to commodity price variability related to our power generation business. Our commercial team manages these commodity price risks with financially settled and other types of contracts consistent with our commodity risk management policy. Our treasury team manages our financial risks and exposures associated with interest rate risk.

Our commodity risk management policy gives us the flexibility to sell energy and capacity and purchase fuel through a combination of spot market sales and near-term contractual arrangements (generally over a rolling one- to three-year time frame). Our commodity risk management goal is to protect cash flow in the near-term while keeping the ability to capture value longer-term.

Many of our contractual arrangements are derivative instruments and are accounted for at fair value as part of Revenues in our unaudited consolidated statements of operations. We manage commodity price risk by entering into capacity forward sales arrangements, tolling arrangements, RMR contracts, fixed price coal purchases and other arrangements that do not receive recurring fair value accounting treatment because these arrangements do not meet the definition of a derivative or are designated as “normal purchase, normal sale,” in accordance with ASC 815. As a result, the gains and losses with respect to these arrangements are not reflected in the unaudited consolidated statements of operations until the delivery occurs.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Quantitative Disclosures Related to Financial Instruments and Derivatives

As of June 30, 2014, we had net purchases and sales of derivative contracts outstanding in the following quantities:

Contract Type (dollars and quantities in millions)	Hedge Designation	Quantity Purchases (Sales)	Unit of Measure	Fair Value (1) Asset (Liability)
Commodity contracts:				
Electricity derivatives (2)	Not designated	(29)	MWh	$(83)
Electricity basis derivatives (3)	Not designated	(36)	MWh	$7
Natural gas derivatives (2)	Not designated	79	MMBtu	$(3)
Natural gas basis derivatives	Not designated	38	MMBtu	$(10)
Diesel fuel derivatives	Not designated	10	Gallon	$—
Coal derivatives	Not designated	—	Metric Ton	$(2)
Heat rate derivatives	Not designated	—	MWh/MMBtu	$(1)
Emissions derivatives	Not designated	2	Metric Ton	$—
Interest rate swaps	Not designated	789	U.S. Dollar	$(45)
Common stock warrants (4)	Not designated	16	Warrant	$(70)

(1) Includes both asset and liability risk management positions, but excludes margin and collateral netting of $8 million.
(2) Mainly comprised of swaps, options and physical forwards.
(3) Comprised of FTRs and swaps.
(4) Each warrant is convertible into one share of Dynegy common stock.

Derivatives on the Balance Sheet. The following tables present the fair value and balance sheet classification of derivatives in the unaudited consolidated balance sheets as of June 30, 2014 and December 31, 2013. As of June 30, 2014 and December 31, 2013, there were no gross amounts available to be offset that were not offset in our unaudited consolidated balance sheets.

		June 30, 2014			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$112	$(91)	$	$21
Total derivative assets		$112	$(91)	$—	$21
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(204)	$91	$8	$(105)
Interest rate contracts	Liabilities from risk management activities	(45)	—	—	(45)
Common stock warrants	Other long-term liabilities	(70)	—	—	(70)
Total derivative liabilities		$(319)	$91	$8	$(220)

Total derivatives	$(207)	$—	$8	$(199)

9

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

		December 31, 2013			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$103	$(67)	$—	$36
Total derivative assets		$103	$(67)	$—	$36
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(122)	$67	$4	$(51)
Interest rate contracts	Liabilities from risk management activities	(47)	—	—	(47)
Common stock warrants	Other long-term liabilities	(21)	—	—	(21)
Total derivative liabilities		$(190)	$67	$4	$(119)
Total derivatives		$(87)	$—	$4	$(83)

Certain of our derivative instruments have credit limits that require us to post collateral. The amount of collateral required to be posted is a function of the net liability position of the derivative as well as our established credit limit with the respective counterparty. If our credit rating were to change, the counterparties could require us to post additional collateral. The amount of additional collateral that would be required to be posted would vary depending on the extent of change in our credit rating as well as the requirements of the individual counterparty. The aggregate fair value of all commodity derivative instruments with credit-risk-related contingent features that are in a liability position that are not fully collateralized (excluding transactions with our clearing brokers that are fully collateralized) at June 30, 2014 is less than $1 million for which we have posted no collateral. Our remaining derivative instruments do not have credit-related collateral contingencies as they are included within our first-lien collateral program.

The following table summarizes our total cash collateral posted as of June 30, 2014 and December 31, 2013, along with the location on the balance sheet and the amount applied against our short-term risk management liabilities.

	June 30, 2014		December 31, 2013	
Location on balance sheet	Collateral posted	Amount applied against short-term risk management liabilities	Collateral posted	Amount applied against short-term risk management liabilities
(amounts in millions)				
Prepayments and other current assets	$53	$8	$47	$4

Impact of Derivatives on the Consolidated Statements of Operations

The following discussion and tables present the location and amount of gains and losses on derivative instruments in our unaudited consolidated statements of operations.

Financial Instruments Not Designated as Hedges. We elect not to designate derivatives related to our power generation business and interest rate instruments as cash flow or fair value hedges. Thus, we account for changes in the fair value of these derivatives within the consolidated statements of operations (herein referred to as "mark-to-market" accounting treatment).

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

The impact of mark-to-market gains (losses) on our unaudited consolidated statements of operations for the three and six months ended June 30, 2014 and 2013 is presented below.

Derivatives Not Designated as Hedges	Location of Mark-to-market Gain (Loss) in Income on Derivatives	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
(amounts in millions)					
Commodity contracts	Revenues	$(15)	$1	$(75)	$(37)
Interest rate contracts	Interest expense	$(5)	$4	$2	$4
Common stock warrants	Other income (expense), net	$(43)	$(9)	$(49)	$(9)

The recognized impact of derivative financial instruments on our unaudited consolidated statements of operations for the three and six months ended June 30, 2014 and 2013 is presented below.

Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
(amounts in millions)					
Commodity contracts	Revenues	$(36)	$(16)	$(209)	$(50)
Commodity contracts, affiliates	Revenues	$—	$—	$—	$(2)
Interest rate contracts	Interest expense	$(10)	$3	$(7)	$3
Common stock warrants	Other income (expense), net	$(43)	$(9)	$(49)	$(9)

Note 5—Fair Value Measurements

We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We have consistently used this valuation technique for all periods presented. Please read Note 2—Summary of Significant Accounting Policies—Fair Value Measurements in our Form 10-K for further discussion.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014 and December 31, 2013 and are presented on a gross basis before consideration of amounts netted under master netting agreements and the application of collateral and margin paid.

	Fair Value as of June 30, 2014			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$54	$43	$97
Natural gas derivatives	—	15	—	15
Total assets from commodity risk management activities	$—	$69	$43	$112
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(116)	$(57)	$(173)
Natural gas derivatives	—	(28)	—	(28)
Heat rate derivatives	—	—	(1)	(1)
Coal derivatives	—	(2)	—	(2)
Total liabilities from commodity risk management activities	—	(146)	(58)	(204)
Liabilities from interest rate contracts	—	(45)	—	(45)
Liabilities from outstanding common stock warrants	(70)	—	—	(70)
Total liabilities	$(70)	$(191)	$(58)	$(319)

	Fair Value as of December 31, 2013			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$44	$50	$94
Natural gas derivatives	—	9	—	9
Total assets from commodity risk management activities	$—	$53	$50	$103
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(55)	$(39)	$(94)
Natural gas derivatives	—	(21)	—	(21)
Heat rate derivatives	—	—	(1)	(1)
Emissions derivatives	—	(2)	—	(2)
Coal derivatives	—	(4)	—	(4)
	—	(82)	(40)	(122)

Total liabilities from commodity risk management activities				
Liabilities from interest rate contracts	—	(47)	—	(47)
Liabilities from outstanding common stock warrants	(21)	—	—	(21)
Total liabilities	$(21)	$(129)	$(40)	$(190)

12

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Level 3 Valuation Methods. The electricity derivatives classified within Level 3 include financial swaps executed in illiquid trading locations, capacity contracts, off-peak power options, heat rate derivatives and FTRs. The curves used to generate the fair value of the financial swaps are based on basis adjustments applied to forward curves for liquid trading points, while the curves for the capacity deals are based upon auction results in the marketplace, which are infrequently executed. Off-peak power options are valued using a Black-Scholes model which uses forward prices and market implied volatility. The forward market price of FTRs is derived using historical congestion patterns within the marketplace and heat rate derivative valuations are derived using a Black-Scholes spread model, which uses forward natural gas and power prices, market implied volatilities and modeled power/natural gas correlation values.
Sensitivity to Changes in Significant Unobservable Inputs for Level 3 Valuations. The significant unobservable inputs used in the fair value measure of our commodity instruments categorized within Level 3 of the fair value hierarchy are estimates of future price correlation, future market volatility, forward congestion power price spreads and illiquid power location pricing basis to liquid locations. These estimates are generally independent of each other. Volatility curves and power price spreads are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price or volatility of the spread on a long/short position in isolation would result in a higher/lower fair value measurement.
The significant unobservable inputs used in the valuation of Dynegy's contracts classified as Level 3 as of June 30, 2014 are as follows:

Transaction Type	Quantity	Unit of Measure	Net Fair Value	Valuation Technique	Significant Unobservable Input	Significant Unobservable Inputs Range
(dollars in millions)						
Electricity derivatives:						
Forward contracts—power (1)	(15)	Million MWh	$(20)	Basis spread + liquid location	Basis spread	$7.00-$9.00
FTRs	(26)	Million MWh	$6	Historical congestion	Forward price	$0.00-$11.00
Heat rate derivatives	112	Thousand Tons	$(1)	Option model	Coal/power price correlation	0%-14%
	(198)	Thousand MWh	$—	Option model	Power price volatility	28%-48%

(1) Represents forward financial and physical transactions at illiquid pricing locations.

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

	Three Months Ended June 30, 2014		
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Total
Balance at March 31, 2014	$(10)	$(1)	$(11)
Total losses included in earnings	(3)	—	(3)
Settlements (1)	(1)	—	(1)
Balance at June 30, 2014	$(14)	$(1)	$(15)
Mark-to-market losses relating to instruments held as of June 30, 2014	$(3)	$—	$(3)

(amounts in millions)	Six Months Ended June 30, 2014 Electricity Derivatives	Heat Rate Derivatives	Total
Balance at December 31, 2013	$11	$(1)	$10
Total losses included in earnings	(22)	—	(22)
Settlements (1)	(3)	—	(3)
Balance at June 30, 2014	$(14)	$(1)	$(15)
Mark-to-market losses relating to instruments held as of June 30, 2014	$(22)	$—	$(22)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

	Three Months Ended June 30, 2013		
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Total
Balance at March 31, 2013	$—	$3	$3
Total losses included in earnings	—	(2)	(2)
Settlements (1)	(3)	—	(3)
Balance at June 30, 2013	$(3)	$1	$(2)
Mark-to-market losses relating to instruments held as of June 30, 2013	$—	$(2)	$(2)

	Six Months Ended June 30, 2013		
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Total
Balance at December 31, 2012	$5	$2	$7
Total losses included in earnings	—	(1)	(1)
Settlements (1)	(8)	—	(8)
Balance at June 30, 2013	$(3)	$1	$(2)
Mark-to-market losses relating to instruments held as of June 30, 2013	$—	$(1)	$(1)

(1) For purposes of these tables, we define settlements as the beginning of period fair value of contracts that settled during the period.

Gains and losses recognized for Level 3 recurring items are included in Revenues on the unaudited consolidated statements of operations for commodity derivatives. We believe an analysis of commodity instruments classified as Level 3 should be undertaken with the understanding that these items generally serve as economic hedges of our power generation portfolio. We did not have any transfers between Level 1, Level 2 and Level 3 for the three and six months ended June 30, 2014 and 2013.

Nonfinancial Assets and Liabilities. Nonfinancial assets and liabilities that are measured at fair value on a nonrecurring basis are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

We did not have any material nonfinancial assets or liabilities measured at fair value on a non-recurring basis during the three and six months ended June 30, 2014 and 2013.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Fair Value of Financial Instruments. The following table discloses the fair value of financial instruments recognized on our balance sheets. Unless otherwise noted, the fair value of debt as reflected in the table has been calculated based on the average of certain available broker quotes as of June 30, 2014 and December 31, 2013, respectively.

(amounts in millions)	June 30, 2014 Carrying Amount	June 30, 2014 Fair Value	December 31, 2013 Carrying Amount	December 31, 2013 Fair Value
Dynegy Inc.:				
Tranche B-2 Term Loan, due 2020 (1)(2)	$(789)	$(795)	$(792)	$(802)
5.875% Senior Notes, due 2023 (2)	$(500)	$(502)	$(500)	$(468)
Emissions Repurchase Agreements (2)	$(29)	$(39)	$(17)	$(17)
Interest rate derivatives (2)	$(45)	$(45)	$(47)	$(47)
Commodity-based derivative contracts (3)	$(92)	$(92)	$(19)	$(19)
Common stock warrants (4)	$(70)	$(70)	$(21)	$(21)
Genco:				
7.95% Senior Notes Series F, due 2032 (2)(5)	$(223)	$(279)	$(224)	$(216)
7.00% Senior Notes Series H, due 2018 (2)(5)	$(264)	$(300)	$(259)	$(252)
6.30% Senior Notes Series I, due 2020 (2)(5)	$(203)	$(246)	$(200)	$(196)

(1) Carrying amount includes an unamortized discount of $3 million and $4 million as of June 30, 2014 and December 31, 2013, respectively. Please read Note 9—Debt for further discussion.
(2) The fair values of these financial instruments are classified as Level 2 within the fair value hierarchy levels.
(3) Carrying amount of commodity-based derivative contracts excludes $8 million and $4 million of cash posted as collateral, as of June 30, 2014 and December 31, 2013, respectively.
(4) The fair value of the common stock warrants is classified as Level 1 within the fair value hierarchy levels.
(5) Combined carrying amounts as of June 30, 2014 and December 31, 2013 include unamortized discounts of $135 million and $142 million, respectively. Please read Note 9—Debt for further discussion.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Note 6—Accumulated Other Comprehensive Income

Changes in accumulated other comprehensive income, net of tax, by component, associated with our defined benefit pension and other post-employment benefit plans are as follows:

	Six Months Ended June 30,	
(amounts in millions)	2014	2013
Beginning of period	$58	$11
Current period other comprehensive loss:		
Actuarial loss (net of tax of zero)	(2)	—
Other comprehensive loss before reclassifications	(2)	—
Reclassification of curtailment gain included in net loss (net of tax of zero) (1)	—	(7)
Amortization of unrecognized prior service cost and actuarial loss (net of tax of zero) (2)	(2)	—
Amounts reclassified from accumulated other comprehensive income	(2)	(7)
Net current period other comprehensive loss, net of tax	(4)	(7)
End of period	$54	$4

(1) Amount related to the DNE pension curtailment gain and was recorded in Income from discontinued operations, net of tax on our unaudited consolidated statements of operations. Please read Note 13—Pension and Other Post-Employment Benefit Plans for further discussion.

(2) Amounts are associated with our defined benefit pension and other post-employment benefit plans and are included in the computation of net periodic pension cost. Please read Note 13—Pension and Other Post-Employment Benefit Plans for further discussion.

Note 7—Inventory

A summary of our inventories is as follows:

(amounts in millions)	June 30, 2014	December 31, 2013
Materials and supplies	$83	$81
Coal	117	92
Fuel oil	5	4
Emissions allowances (1)	1	4
Total	$206	$181

(1) This inventory is held as collateral by one of our counterparties as part of a financing arrangement. Please read Note 9—Debt—Emissions Repurchase Agreements for further discussion.

Note 8—Intangible Assets and Liabilities

The following table summarizes the components of our intangible assets and liabilities, on a net basis:

	June 30, 2014		December 31, 2013	
(amounts in millions)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Electricity contracts, net	$325	$(231)	$330	$(170)
Coal contracts, net	39	(128)	39	(150)
Gas transport contracts	(24)	13	(24)	9
Total	$340	$(346)	$345	$(311)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

The following table presents our amortization of intangible assets and liabilities:

	Three Months Ended June 30,		Six Months Ended June 30,	
(amounts in millions)	2014	2013	2014	2013
Electricity contracts, net (1)	$ 32	$ 33	$ 61	$ 67
Coal contracts, net (2)	(11)	33	(22)	64
Gas transport contracts (2)	(2)	(2)	(4)	(4)
Total	$ 19	$ 64	$ 35	$ 127

(1) The amortization expense of these contracts is recognized in Revenues in our unaudited consolidated statements of operations.
(2) The amortization expense of these contracts is recognized in Cost of sales in our unaudited consolidated statements of operations.

Note 9—Debt

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

(amounts in millions)	June 30, 2014	December 31, 2013
Dynegy Inc.:		
Tranche B-2 Term Loan, due 2020 (1)	$ 792	$ 796
5.875% Senior Notes, due 2023 (1)	500	500
Emissions Repurchase Agreements (1)	29	17
Genco:		
7.95% Senior Notes Series F, due 2032 (1)	275	275
7.00% Senior Notes Series H, due 2018 (1)	300	300
6.30% Senior Notes Series I, due 2020 (1)	250	250
	2,146	2,138
Unamortized discount on debt, net	(138)	(146)
	2,008	1,992
Less: Current maturities, including unamortized discounts, net	37	13
Total Long-term debt	$ 1,971	$ 1,979

(1) Please read Note 12—Debt in our Form 10-K for further discussion.

The Company has a $1.275 billion credit agreement that consists of (i) an $800 million seven-year senior secured term loan B facility (the “Tranche B-2 Term Loan”) and (ii) a $475 million five-year senior secured revolving credit facility (the “Revolving Facility,” and collectively with the Tranche B-2 Term Loan, the “Credit Agreement”). Dynegy and its Subsidiary Guarantors also entered into an indenture pursuant to which Dynegy issued $500 million in aggregate principal amount of unsecured senior notes (the “Senior Notes”) at par.

At June 30, 2014, there were no amounts drawn on the Revolving Facility; however, we had outstanding letters of credit of approximately $181 million, which reduces the amount available under the Revolving Facility.

The Credit Agreement contains customary events of default and affirmative and negative covenants, subject to certain specified exceptions, including a Senior Secured Leverage Ratio (as defined in the Credit Agreement) calculated on a rolling four quarters basis. Based on the calculation outlined in the Credit Agreement, we are in compliance at June 30, 2014.

Genco Senior Notes

On December 2, 2013, in connection with the AER Acquisition, Genco’s approximately $825 million in aggregate principal amount of unsecured senior notes (the “Genco Senior Notes”) remained outstanding as an obligation of Genco, a subsidiary of

17

IPH. The Genco Senior Notes bear interest at rates from 6.30 percent per annum to 7.95 percent per annum and mature between 2018 and 2032.

Genco's indenture includes provisions that require Genco to maintain certain interest coverage and debt-to-capital ratios in order for Genco to pay dividends, to make principal or interest payments on subordinated borrowings, to make loans to or investments in affiliates, or to incur additional external, third-party indebtedness.

The following table summarizes these required ratios:

	Required Ratio
Restricted payment interest coverage ratio (1)	≥1.75
Additional indebtedness interest coverage ratio (2)	≥2.50
Additional indebtedness debt-to-capital ratio (2)	≤60%

(1) As of the date of a restricted payment, as defined, the minimum ratio must have been achieved for the most recently ended four fiscal quarters and projected by management to be achieved for each of the subsequent four six-month periods.

(2) Ratios must be computed on a pro forma basis considering the additional indebtedness to be incurred and the related interest expense. Other borrowings from third-party external sources are included in the definition of indebtedness and are subject to these incurrence tests.

Genco's debt incurrence-related ratio restrictions under the indenture may be disregarded if both Moody's and S&P reaffirm the ratings in place at the time of the debt incurrence after considering the additional indebtedness.

Based on June 30, 2014 calculations, Genco's interest coverage ratios are less than the minimum ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources. Based on our projections, we expect that Genco's interest coverage ratios will be less than the minimum ratios required for Genco to pay dividends and incur additional third-party indebtedness until at least 2016.

Illinois Power Marketing

On January 29, 2014, IPM entered into a fully cash collateralized Letter of Credit and Reimbursement Agreement with Union Bank, N.A., as amended on May 16, 2014 ("LC Agreement"), pursuant to which Union Bank agreed to issue from time to time, one or more standby letters of credit in an aggregate stated amount not to exceed $25 million at any one time to support performance obligations and other general corporate activities of IPM, provided that IPM deposits in an account controlled by Union Bank an amount of cash sufficient to cover the face value of such requested letter of credit plus an additional percentage thereon. Currently, IPM has deposited $10.5 million with Union Bank and issued $10 million in Letters of Credit.

Emissions Repurchase Agreements

During the fourth quarter 2013, we entered into two repurchase transactions with a third party in which we sold $6 million in California Carbon Allowances ("CCA") credits and $11 million of Regional Greenhouse Gas Initiative ("RGGI") inventory and received cash. In the first quarter 2014, we entered into an additional repurchase agreement with a third party in which we sold $12 million RGGI inventory and received cash. We are obligated to repurchase the CCA credits in October 2014 and RGGI inventory in February 2015 at a specified price that includes a carry cost of approximately 350 basis points.

Note 10—Commitments and Contingencies

Legal Proceedings

Set forth below is a summary of our material ongoing legal proceedings. We record accruals for estimated losses from contingencies when available information indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. In addition, we disclose matters for which management believes a material loss is reasonably possible. In all instances, management has assessed the matters below based on current information and made judgments concerning their potential outcome, giving consideration to the nature of the claim, the amount, if any, and nature of damages sought and the probability of success. Management regularly reviews all new information with respect to such contingency and adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties including

18

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

unfavorable rulings or developments, it is possible that the ultimate resolution of our legal proceedings could involve amounts that are different from our currently recorded accruals and that such differences could be material.

In addition to the matters discussed below, we are party to other routine proceedings arising in the ordinary course of business or related to discontinued business operations. Any accruals or estimated losses related to these matters are not material. In management’s judgment, the ultimate resolution of these matters will not have a material effect on our financial condition, results of operations or cash flows.

Stockholder Litigation Relating to the 2011 Prepetition Restructuring. In connection with the prepetition restructuring and corporate reorganization of the DH Debtor Entities and their non-debtor affiliates in 2011 (the “2011 Prepetition Restructuring”), and specifically the transfer of DMG, a putative class action stockholder lawsuit captioned Charles Silsby v. Carl C. Icahn, et al., Case No. 12CIV2307 (the “Securities Litigation”), was filed in the U.S. District Court for the Southern District of New York. The lawsuit challenged certain disclosures made in connection with the transfer of DMG. As a result of the filing of the voluntary petition for bankruptcy by Dynegy Inc., this lawsuit was stayed as against Dynegy Inc. and as a result of the confirmation of the Joint Chapter 11 Plan (the “Plan”), the claims against Dynegy Inc. in the Securities Litigation are permanently enjoined.

On August 24, 2012, the lead plaintiff in the Securities Litigation filed an objection to the confirmation of the Plan asserting, among other things, that lead plaintiff should be permitted to opt-out of the non-debtor releases and injunctions (the “Non-Debtor Releases”) in the Plan on behalf of all putative class members. We opposed that relief. On October 1, 2012, the Bankruptcy Court ruled that lead plaintiff did not have standing to object to the Plan and did not have authority to opt-out of the Non-Debtor Releases on behalf of any other party-in-interest. Accordingly, the Securities Litigation may only proceed against the non-debtor defendants with respect to members of the putative class who individually opted out of the Non-Debtor Releases. The lead plaintiff filed a notice of appeal on October 10, 2012. On June 4, 2013, the District Court dismissed the appeal. On July 3, 2013, the lead plaintiff filed a notice of appeal with the U.S. Court of Appeals for the Second Circuit and filed a brief on November 4, 2013. On July 19, 2013, the defendants filed a substantive motion to dismiss the plaintiff's remaining claims. On April 30, 2014, the District Court granted the defendants’ motion and dismissed the action. Plaintiff filed a notice of appeal of this decision.

Gas Index Pricing Litigation. We, several of our affiliates, our former joint venture affiliate and other energy companies were named as defendants in numerous lawsuits in state and federal court claiming damages resulting from alleged price manipulation and false reporting of natural gas prices to various index publications in the 2000-2002 time frame. Many of the cases have been resolved. All of the remaining cases contain similar claims that we individually, and in conjunction with other energy companies, engaged in an illegal scheme to inflate natural gas prices in four states by providing false information to natural gas index publications. In July 2011, the court granted defendants’ motions for summary judgment, thereby dismissing all of plaintiffs’ claims. Plaintiffs appealed the decision to the U.S. Court of Appeals for the Ninth Circuit which reversed the summary judgment on April 10, 2013. On August 26, 2013, we and the other defendants filed a request for review with the U.S. Supreme Court. On July 1, 2014, the Supreme Court accepted review. Oral arguments have not yet been set.

Illinova Generating Company Arbitration. In May 2007, our subsidiary Illinova Generating Company (“IGC”) received an adverse award in an arbitration brought by Ponderosa Pine Energy, LLC (“PPE”). The award required IGC to pay PPE $17 million, which IGC paid in June 2007 under protest while simultaneously seeking to vacate the award in the District Court of Dallas County, Texas. In March 2010, the Dallas District Court vacated the award, finding that one of the arbitrators had exhibited evident partiality. PPE appealed that decision to the Fifth District Court of Appeals in Dallas, Texas. Coincident with the appeal, IGC filed a claim against PPE seeking recovery of the $17 million plus interest. In September 2010, the Dallas District Court ordered PPE to deposit the $17 million principal in an interest-bearing escrow account jointly owned by IGC and PPE. On August 20, 2012, the Dallas Court of Appeals reversed the Dallas District Court and reinstated the award. IGC and the other respondents filed a petition for review with the Texas Supreme Court on December 5, 2012. On May 23, 2014, the Texas Supreme Court reversed the Dallas

Court of Appeals and reinstated the trial court's judgment vacating the arbitration award. PPE has sought rehearing in the Texas Supreme Court.

Pacific Northwest Refund Proceedings. Dynegy Power Marketing, LLC ("DYPM"), along with numerous other companies that sold power in the Pacific Northwest in 2000-2001, are parties to a complaint filed in 2001 with FERC challenging bilateral contract pricing by claiming manipulation of the electricity market in California produced unreasonable prices in the Pacific Northwest. DYPM previously settled all California refund claims, but did not settle with certain complainants seeking refunds in the Pacific Northwest including The City of Seattle ("Seattle"). On October 1, 2012, DYPM and Seattle reached a settlement whereby DYPM agreed to pay Seattle $180 thousand (inclusive of all interest) to settle all claims between Seattle and DYPM in these proceedings. On November 29, 2012, FERC issued a letter order approving the settlement agreement. There is

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

a risk for "ripple claims" from other sellers, but the efficacy of these claims is currently being litigated and any potential impact to DYPM from ripple claims is impossible to predict at this stage.

Other Contingencies

Dam Safety Assessment Reports. In response to the failure of a CCR surface impoundment dike at the TVA's Kingston Plant in Tennessee, the EPA initiated a nationwide investigation of the structural integrity of CCR surface impoundments. The EPA assessments found all of our surface impoundments to be in satisfactory or fair condition, with the exception of the surface impoundments at the Baldwin and Hennepin facilities. In March 2013, the EPA issued final dam safety assessment reports of the surface impoundments at our Baldwin and Hennepin facilities. The reports rate the impoundments at each facility as "poor," meaning that a deficiency is recognized for a required loading condition in accordance with applicable dam safety criteria. A poor rating also applies when certain documentation is lacking or incomplete or if further critical studies are needed to identify any potential dam safety deficiencies. The reports include recommendations for further studies, repairs and changes in operational and maintenance practices.

In response to the Hennepin final report, we notified the EPA in July 2013 of our intent to close the Hennepin west CCR surface impoundment. The preliminary estimated cost for closure of the west CCR surface impoundment, including post-closure monitoring, is approximately $5 million. As a result of these changes, we increased our ARO by approximately $2 million during the second quarter 2013. We are performing further studies needed to support closure of the west CCR impoundment. In March 2014, we received the Illinois Department of Natural Resources permit needed to begin construction on the capital improvements to the east dam berm. The estimated cost for capital improvements to the Hennepin east dam is approximately $2 million. Work is anticipated to start in the third quarter 2014, depending upon river levels.

In response to the Baldwin final report, we notified the EPA in April 2013 of our action plan, which included implementation of recommended operational and maintenance practices and certain recommended studies. In May 2014, we updated the EPA on the status of our Baldwin action plan, including the completion of certain studies and implementation of remedial measures and our ongoing evaluation of potential long-term measures in the context of our concurrent ongoing evaluation at Baldwin of groundwater corrective actions. The nature and scope of repairs that ultimately may be needed at the Baldwin CCR surface impoundment to address the EPA's dam safety assessment is dependent, in part, on the Illinois EPA's response to our groundwater corrective action evaluation recommendations. Please read "Vermilion and Baldwin Groundwater" below for further discussion. At this time, if the Illinois EPA approves our proposed approach to address groundwater at Baldwin and the EPA concurs, we estimate the cost to repair the affected berm at the Baldwin CCR surface impoundment system would be approximately $1 million. If such approach is not approved by the Illinois EPA we are unable, at this time, to estimate a reasonably possible cost, or range of costs, of repairs at the Baldwin CCR surface impoundment.

New Source Review and Clean Air Litigation. Since 1999, the EPA has been engaged in a nationwide enforcement initiative to determine whether coal-fired power plants failed to comply with the requirements of the NSR and NSPS provisions under the CAA when the plants implemented modifications. The EPA's initiative focuses on whether projects performed at power plants triggered various permitting requirements, including the need to install pollution control equipment.

Wood River CAA Section 114 Information Request. In May 2014, we received an information request from the EPA concerning our Coal segment's Wood River Station's compliance with the Illinois State Implementation Plan and associated permits. We responded to the EPA's request and are currently unable to predict the EPA's response, if any.

IPH Segment CAA Section 114 Information Requests. Commencing in 2005, the IPH facilities received a series of information requests from the EPA pursuant to Section 114(a) of the CAA. The requests sought detailed operating and maintenance history data with respect to the Coffeen, Newton, Edwards, Duck Creek and Joppa facilities. In August 2012, the EPA issued a Notice of Violation alleging that projects performed in 1997, 2006 and 2007 at the Newton facility violated PSD, Title V permitting and other requirements. We believe our defenses to the allegations described in the Notice of Violation are meritorious. A recent decision by the U.S. Court of Appeals for the Seventh Circuit held that similar claims older than five years were barred by the statute of limitations. If not overturned, this decision may provide an additional defense to the allegations in the Newton facility Notice of Violation. Ultimate resolution of these matters could have a material adverse impact on IPH's future financial condition, results of operations and cash flows. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses and penalties. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve these matters.

Edwards CAA Litigation. In April 2013, environmental groups filed a CAA citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our IPH segment's Edwards facility.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

The District Court has scheduled the trial date for February 2016. IPH disputes the allegations and will defend the case vigorously. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve this matter.

IPH Variance. In January 2014, an environmental group filed a petition for review in the Illinois Fourth District Appellate Court of the IPCB's November 2013 decision and order granting the variance relief to IPH. On January 17, 2014, we filed a Motion to Dismiss. On February 24, 2014, the Fourth District Appellate Court granted our motion and dismissed the appeal. On April 1, 2014, the environmental group filed a petition for leave to appeal the Appellate Court's decision with the Illinois Supreme Court. On May 5, 2014, we filed an answer opposing review by the Illinois Supreme Court. We believe the variance was properly granted and that the Appellate Court's judgment dismissing the petition for review was proper. We will vigorously defend our position.

Vermilion and Baldwin Groundwater. We have implemented hydrogeologic investigations for the CCR surface impoundment at our Baldwin facility and for two CCR surface impoundments at our Vermilion facility in response to a request by the Illinois EPA.

Groundwater monitoring results indicate that the CCR surface impoundment at Baldwin impacts onsite groundwater. Also, at the request of the Illinois EPA, in late 2011 we initiated an investigation at Baldwin to determine if the facility's CCR surface impoundment impacts offsite groundwater. Results of the offsite groundwater quality investigation at Baldwin, as submitted to the Illinois EPA on April 24, 2012, indicate two localized areas where Class I groundwater standards were exceeded, but the Illinois EPA has not required further investigation. If these offsite groundwater results are ultimately attributed to the Baldwin CCR surface impoundment and remediation measures are necessary in the future, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. At this time we cannot reasonably estimate the costs, or range of costs, of corrective action that ultimately may be required at Baldwin.

In April 2012, we submitted to the Illinois EPA proposed corrective action plans for two of the CCR surface impoundments at the Vermilion facility. The proposed corrective action plans reflect the results of a hydrogeologic investigation, which indicate that the facility's old east and north CCR impoundments impact groundwater quality onsite and that such groundwater migrates offsite to the north of the property and to the adjacent Middle Fork of the Vermilion River. The proposed corrective action plans include groundwater monitoring and recommend closure of both CCR impoundments, including installation of a geosynthetic cover. In addition, we submitted an application to the Illinois EPA to establish a groundwater management zone while impacts from the facility are mitigated. In March 2014, we submitted a revised corrective action plan for the old east impoundment at Vermilion. Our preliminary estimated cost of the recommended closure alternative for both Vermilion impoundments, including post-closure care, is approximately $10 million. The Vermilion facility also has a third CCR surface impoundment, the new east impoundment that is lined and is not known to impact groundwater. Although not part of the proposed corrective action plans, if we decide to close the new east impoundment by removing its CCR contents concurrent with the recommended closure alternative for the old east and north impoundments, the associated estimated closure cost would add an additional $2 million to the above estimate.

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In December 2012, the Illinois EPA provided written notice that it may pursue legal action with respect to each matter through referral to the Illinois Office of the Attorney General. In accordance with work plans approved by the Illinois EPA, in 2013 we performed a geotechnical study at Vermilion and began a 12-month geotechnical/hydraulic/hydrogeologic study needed to analyze corrective action alternatives at Baldwin. The geotechnical study at Vermilion confirmed that the cap closure option proposed in our corrective action plans for the north and old east CCR surface impoundments is technically feasible. In June 2014, we submitted the results of our evaluation at Baldwin to the Illinois EPA. Based on the results of that evaluation, we recommended to the Illinois EPA that the closure process for the out-of-service east fly ash impoundment begin and that a geotechnical investigation of the existing soil cap on the out-of-service old east fly ash impoundment be undertaken. At this time we cannot reasonably estimate the costs of resolving these enforcement matters, but resolution of these matters may cause us to incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows.

IPH Segment Groundwater. Hydrogeologic investigations of the CCR surface impoundments have been performed at the IPH segment facilities. Groundwater monitoring results indicate that the CCR surface impoundments at each of the IPH segment facilities potentially impact onsite groundwater.

In 2012, the Illinois EPA issued violation notices with respect to groundwater conditions at the Newton and Coffeen facilities' CCR surface impoundments. In February 2013, the Illinois EPA provided written notice that it may pursue legal action with respect to each of these matters through referral to the Illinois Office of the Attorney General. In April 2013, AER filed a proposed rulemaking with the IPCB which, if approved, would provide for the systematic and eventual closure of certain CCR surface impoundments. In October 2013, the Illinois EPA filed a proposed rulemaking with the IPCB that would establish processes governing monitoring, preventative response, corrective action and closure of CCR surface impoundments at all power generating facilities in Illinois. The AER rulemaking (now IPH) has been stayed to allow the Illinois EPA proposed rulemaking to proceed. At this time we cannot reasonably estimate the costs or range of costs of resolving the Newton and Coffeen enforcement matters, but resolution of these matters may cause IPH to incur significant costs that could have a material adverse effect on its financial condition, results of operations and cash flows.

Station Power Proceedings. On May 4, 2010, the U.S. Court of Appeals for the District of Columbia Circuit (the “D.C. Circuit”) vacated FERC’s acceptance of station power rules for the CAISO market and remanded the case for further proceedings at FERC. On August 30, 2010, FERC issued an Order on Remand (“remand order”) effectively disclaiming jurisdiction over how the states impose retail station power charges. Due to reservation-of-rights language in the California utilities’ state-jurisdictional station power tariffs, the California utilities have argued that FERC’s ruling requires California generators to pay state-imposed retail charges back to the date of enrollment by the facilities in the CAISO’s station period program. The remand order could impact FERC’s station power policies in all of the organized markets throughout the nation. On February 28, 2011, the FERC issued an order denying rehearing of the remand order. Dynegy Moss Landing, LLC, together with other generators, filed an appeal of the remand order in the D.C. Circuit. On December 18, 2012, the D.C. Circuit issued an order denying the appeal of the generator group and affirming FERC’s orders on remand.

On November 18, 2011, PG&E filed with the CPUC, seeking authorization to begin charging generators station power charges, and to assess such charges retroactively, which the Company and other generators have challenged. Dynegy Morro Bay, LLC, Dynegy Moss Landing, LLC and Dynegy Oakland, LLC filed a protest with the CPUC objecting to PG&E’s filing. On October 25, 2013, PG&E filed revisions to its November 18, 2011 Advice Letter, seeking to limit retroactive charges to December 18, 2012 forward, rather than from April 2006 to present, as originally proposed. The October 2013 filing also proposed a 15-minute netting interval. On July 14, 2014, the CPUC’s Energy Division issued a Draft Resolution that orders retroactive charges to be assessed against generators dating back to August 30, 2010. Comments on the Draft Resolution are due August 4, 2014 and the Draft Resolution is currently scheduled to be voted on at the CPUC’s August 14, 2014 meeting. We believe we have established an appropriate accrual.

Other Commitments

In conducting our operations, we have routinely entered into long-term commodity purchase and sale commitments, as well as agreements that commit future cash flow to the lease or acquisition of assets used in our businesses. These commitments have been typically associated with commodity supply arrangements, capital projects, reservation charges associated with firm transmission, transportation, storage and leases for office space, equipment, design and construction, plant sites, power generation assets and LPG vessel charters. The following describes the more significant commitments outstanding at June 30, 2014.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. In June 2013, we amended our maintenance agreements. The term of the agreements will be determined by the maintenance cycles of the respective facility. We currently estimate these agreements will be in effect for a period of 15 or more years. Either party can terminate the agreements based on certain events as specified in the contracts. As of June 30, 2014, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $149 million and $218 million in the event all contracts are terminated by us or the counterparty, respectively.

Charter Agreements. In addition, we are party to two charter agreements related to very large gas carriers (“VLGCs”) previously utilized in our former global liquids business. The primary term of one charter expired at the end of September 2013 but has been extended for a second consecutive year. The primary term of the second charter is through September 2014 but has been extended for a period of one year at the sole option of the counterparty. Both of these VLGCs have been sub-chartered to a wholly-owned subsidiary of Transammonia Inc. on terms that are identical to the terms of the original charter agreements. The aggregate minimum base commitments of the charter party agreements are approximately $7 million and $11 million for the years ended December 31, 2014 and 2015, respectively. To date, the subsidiary of Transammonia Inc. has complied with the terms of the sub-charter agreement.

Indemnifications and Guarantees

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

Indemnities

In connection with the LS Power Transaction, the sale of Illinois Power Company, the sale of our midstream business, and certain other sales transactions involving former assets, we entered into indemnifications regarding environmental, tax, employee and other representations. Even though Dynegy was discharged from any claims pursuant to the Plan and the order confirming the Plan (the "Confirmation Order"), several Dynegy subsidiaries remain jointly and severally liable for any indemnification claims depending on the terms of the applicable transaction agreement. Although certain of the indemnification obligations are indefinite, some have exceeded the survival period in the relevant transaction agreements or have exceeded the applicable statute of limitations. In addition, some of these indemnification obligations are subject to individual thresholds and/or maximum aggregate limits depending on the terms of the transaction agreement. As of June 30, 2014, no claims have been made against us and we have not recorded a liability for these indemnities.

Guarantees

Limited Guaranty. In connection with the AER Acquisition, Dynegy has provided a Limited Guaranty of certain obligations of IPH up to $25 million. Concurrently with the execution of the AER Transaction Agreement, Dynegy entered into the Limited Guaranty, capped at $25 million in favor of Ameren, for a period of two years after the closing (subject to certain exceptions) with respect to IPH's indemnification obligations and certain reimbursement obligations under the AER Transaction Agreement.

Note 11—Related Party Transactions

Service Agreements. Certain of our Dynegy subsidiaries have service agreements with the DNE Debtor Entities. On October 1, 2012, Dynegy deconsolidated the DNE Debtor Entities. There was no power purchased from our unconsolidated affiliate for the three and six months ended June 30, 2014. Our unaudited consolidated statements of operations include $1 million and $3 million of power purchased from our unconsolidated affiliate, which is reflected in Revenues for the three and six months ended June 30, 2013, respectively. Please read Note 13—Related Party Transactions and Note 21—Emergence from Bankruptcy and Fresh-Start Accounting—Chapter 11 Filing and Emergence from Bankruptcy in our Form 10-K for further discussion.

Note 12—Income Taxes

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income or loss, except for significant unusual or extraordinary transactions. Income taxes for significant unusual or extraordinary transactions are computed and recorded in the period that the specific transaction occurs.

For the three months ended June 30, 2014, our overall effective tax rate on continuing operations of two percent was different than the statutory tax rate of 35 percent primarily due to a valuation allowance against our net deferred tax assets and a change in our expected alternative minimum tax for the 2014 tax year.

For the six months ended June 30, 2014, our overall effective tax rate on continuing operations of one percent was different than the statutory tax rate of 35 percent primarily due to a valuation allowance against our net deferred tax assets.

For the three and six months ended June 30, 2013, our overall effective tax rate on continuing operations of zero percent was different than the statutory tax rate of 35 percent primarily due to a valuation allowance against our net deferred tax assets, partially offset by the impact of state taxes.

As of June 30, 2014 and 2013, we did not believe we would produce sufficient future taxable income, nor were there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

On April 14, 2014, we received final notice from the IRS that their audit of our 2012 tax year has been completed. In accordance with accounting guidance in ASC 740, we recognized $270 million of net tax benefits for tax positions included in the

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

2012 tax return that had not previously met the “more likely than not” recognition threshold. These benefits have been recognized in the current period as a discreet item with a corresponding adjustment to the valuation allowance.

Note 13—Pension and Other Post-Employment Benefit Plans

We sponsor and administer defined benefit plans and defined contribution plans for the benefit of our employees and also provide other post-employment benefits to retirees who meet age and service requirements which are more fully described in Note 18—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans in our Form 10-K.

The components of net periodic benefit cost (gain) were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
(amounts in millions)	2014	2013	2014	2013
Service cost benefits earned during period	$3	$2	$—	$—
Interest cost on projected benefit obligation	5	3	1	1
Expected return on plan assets	(6)	(4)	(1)	—
Amortization of:				
Prior service cost	(1)	—	—	—
Net periodic benefit cost	1	1	—	1
Curtailment gain (1)	—	(7)	—	—
Total benefit cost (gain)	$1	$(6)	$—	$1

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
(amounts in millions)	2014	2013	2014	2013
Service cost benefits earned during period	$6	$5	$—	$1
Interest cost on projected benefit obligation	9	6	2	1
Expected return on plan assets	(11)	(9)	(2)	—
Amortization of:				
Prior service cost	(1)	—	(1)	—
Net periodic benefit cost (gain)	3	2	(1)	2
Curtailment gain (1)	—	(7)	—	—
Total benefit cost (gain)	$3	$(5)	$(1)	$2

(1) The curtailment gain is related to the DNE pension plan and resulted from the Roseton sale and the termination of a majority of the Danskammer employees.

Note 14—Loss Per Share

The reconciliation of basic loss per share from continuing operations to diluted loss per share from continuing operations of our common stock outstanding during the three and six months ended June 30, 2014 and 2013 is shown in the following table. Basic loss per share represents the amount of losses for the period available to each share of our common stock outstanding during the periods. Diluted loss per share represents the amount of losses for the periods available to each share of our common stock outstanding during the periods plus each share that would have been outstanding assuming the issuance of common shares for all dilutive potential common shares outstanding during the periods. Please read Note 17—Capital Stock in our Form 10-K for further discussion.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	2014	2013	2014	2013
Loss from continuing operations	$(122)	$(150)	$(159)	$(292)
Less: Net income attributable to noncontrolling interest	1	—	5	—
Loss from continuing operations attributable to Dynegy Inc. for basic and diluted loss per share	$(123)	$(150)	$(164)	$(292)
Basic weighted-average shares	100	100	100	100
Effect of dilutive securities (1)	1	—	1	—
Diluted weighted-average shares	101	100	101	100
Loss per share from continuing operations attributable to Dynegy Inc.:				
Basic	$(1.23)	$(1.50)	$(1.64)	$(2.92)
Diluted (1)	$(1.23)	$(1.50)	$(1.64)	$(2.92)

---

(1) Entities with a net loss from continuing operations are prohibited from including potential common shares in the computation of diluted per share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for all periods presented.

For the three and six months ended June 30, 2014 and 2013, the following potentially dilutive securities were not included in the computation of diluted per share amounts because the effect would be anti-dilutive:

(in millions of shares)	2014	2013
Stock options	1.4	1.0
Restricted stock units	1.1	0.9
Performance stock units	0.3	0.1
Warrants	15.6	15.6
Total	18.4	17.6

Note 15—Condensed Consolidating Financial Information

On May 20, 2013, Dynegy issued the Senior Notes, as further described in Note 9—Debt. The 100 percent owned Subsidiary Guarantors, jointly, severally and unconditionally, guaranteed the payment obligations under the Senior Notes. Not all of Dynegy's subsidiaries guarantee the Senior Notes including Dynegy's indirect, wholly-owned subsidiary, IPH, which acquired AER and its subsidiaries on December 2, 2013. Prior to December 2, 2013, the non-guarantor subsidiaries were minor.

The following condensed consolidating financial statements present the financial information of (i) Dynegy, which is the parent and issuer, on a stand-alone, unconsolidated basis, (ii) the guarantor subsidiaries of Dynegy, (iii) the non-guarantor subsidiaries of Dynegy and (iv) the eliminations necessary to arrive at the information for Dynegy on a consolidated basis.

These statements should be read in conjunction with the unaudited consolidated statements and notes thereto of Dynegy. The supplemental condensed consolidating financial information has been prepared pursuant to Rule 3-10 of SEC Regulation S-X and does not include all disclosures included in annual financial statements.

For purposes of the Condensed Consolidating Financial Information, a portion of our intercompany receivable which we do not consider to be likely of settlement has been classified as equity as of June 30, 2014 and December 31, 2013.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Condensed Consolidating Balance Sheet as of June 30, 2014
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$587	$145	$ 216	$—	$948
Accounts receivable, net	24	120	266	(43)	367
Intercompany receivable	—	366	—	(366)	—
Inventory	—	83	123	—	206
Other current assets	7	90	84	(3)	178
Total Current Assets	618	804	689	(412)	1,699
Property, Plant and Equipment, Net	—	2,865	395	—	3,260
Other Assets					
Investment in affiliates	6,202	—	—	(6,202)	—
Other long-term assets	94	59	76	—	229
Intercompany note receivable	12	—	—	(12)	—
Total Assets	$6,926	$3,728	$ 1,160	$(6,626)	$5,188
Current Liabilities					
Accounts payable	$—	$92	$ 256	$(43)	$305
Intercompany payable	313	—	53	(366)	—
Other current liabilities	95	216	140	(3)	448
Total Current Liabilities	408	308	449	(412)	753
Long-term debt	1,281	—	690	—	1,971
Intercompany interest payable	799	—	—	(799)	—
Intercompany long-term debt	2,243	—	12	(2,255)	—
Other long-term liabilities	144	132	136	—	412
Total Liabilities	4,875	440	1,287	(3,466)	3,136
Stockholders' Equity					
Dynegy Stockholders' Equity	2,051	6,330	(128)	(6,202)	2,051
Intercompany receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	2,051	3,288	(128)	(3,160)	2,051
Noncontrolling interest	—	—	1	—	1
Total Equity	2,051	3,288	(127)	(3,160)	2,052
Total Liabilities and Equity	$6,926	$3,728	$ 1,160	$(6,626)	$5,188

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Condensed Consolidating Balance Sheet as of December 31, 2013
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$474	$154	$ 215	$—	$843
Accounts receivable, net	2	133	289	(4)	420
Intercompany receivable	—	194	—	(194)	—
Inventory	—	71	110	—	181
Other current assets	8	131	102	—	241
Total Current Assets	484	683	716	(198)	1,685
Property, Plant and Equipment, Net	—	2,937	378	—	3,315
Other Assets					
Investment in affiliates	6,281	—	—	(6,281)	—
Other long-term assets	133	61	97	—	291
Total Assets	$6,898	$3,681	$ 1,191	$(6,479)	$5,291
Current Liabilities					
Accounts payable	$4	$114	$ 215	$(4)	$329
Intercompany payable	127	—	67	(194)	—
Other current liabilities	132	139	121	—	392
Total Current Liabilities	263	253	403	(198)	721
Long-term debt	1,285	11	683	—	1,979
Intercompany interest payable	799	—	—	(799)	—
Intercompany long-term debt	2,243	—	—	(2,243)	—
Other long-term liabilities	98	145	141	—	384
Total Liabilities	4,688	409	1,227	(3,240)	3,084
Stockholders' Equity					
Dynegy Stockholders' Equity	2,210	6,314	(33)	(6,281)	2,210
Intercompany receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	2,210	3,272	(33)	(3,239)	2,210
Noncontrolling interest	—	—	(3)	—	(3)
Total Equity	2,210	3,272	(36)	(3,239)	2,207
Total Liabilities and Equity	$6,898	$3,681	$ 1,191	$(6,479)	$5,291

27

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Condensed Consolidating Statements of Operations for the Three Months Ended June 30, 2014
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 342	$ 179	$ —	$ 521
Cost of sales, excluding depreciation expense	—	(235)	(130)	—	(365)
Gross margin	—	107	49	—	156
Operating and maintenance expense	—	(82)	(54)	—	(136)
Depreciation expense	—	(47)	(10)	—	(57)
Gain on sale of assets, net	—	14	—	—	14
General and administrative expense	(2)	(15)	(12)	—	(29)
Acquisition and integration costs	—	—	(2)	—	(2)
Operating loss	(2)	(23)	(29)	—	(54)
Equity in losses from investments in affiliates	(38)	—	—	38	—
Earnings from unconsolidated investments	—	10	—	—	10
Interest expense	(28)	—	(14)	—	(42)
Other income and expense, net	(39)	—	—	—	(39)
Loss from continuing operations before income taxes	(107)	(13)	(43)	38	(125)
Income tax benefit (expense)	(16)	—	19	—	3
Net loss	(123)	(13)	(24)	38	(122)
Less: Net income attributable to noncontrolling interest	—	—	1	—	1
Loss attributable to Dynegy Inc.	$(123)	$(13)	$ (25)	$ 38	$ (123)

Condensed Consolidating Statements of Operations for the Six Months Ended June 30, 2014
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 900	$ 383	$ —	$ 1,283
Cost of sales, excluding depreciation expense	—	(628)	(289)	—	(917)
Gross margin	—	272	94	—	366
Operating and maintenance expense	—	(145)	(101)	—	(246)
Depreciation expense	—	(106)	(18)	—	(124)
Gain on sale of assets, net	—	14	—	—	14
General and administrative expense	(4)	(29)	(22)	—	(55)
Acquisition and integration costs	—	—	(8)	—	(8)
Operating income (loss)	(4)	6	(55)	—	(53)
Equity in losses from investments in affiliates	(77)	—	—	77	—
Earnings from unconsolidated investments	—	10	—	—	10
Interest expense	(44)	—	(28)	—	(72)
Other income and expense, net	(45)	—	—	—	(45)
	(170)	16	(83)	77	(160)

Income (loss) from continuing operations before income taxes					
Income tax benefit (expense)	6	—	(5)	—	1
Net income (loss)	(164)	16	(88)	77	(159)
Less: Net income attributable to noncontrolling interest	—	—	5	—	5
Income (loss) attributable to Dynegy Inc.	$(164)	$ 16	$ (93)	$ 77	$ (164)

28

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended June 30, 2014

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	$(123)	$(13)	$ (24)	$ 38	$(122)
Amounts reclassified from accumulated other comprehensive income (loss):					
Amortization of unrecognized prior service cost and actuarial loss, net of tax of zero	(1)	—	—	—	(1)
Other comprehensive loss, net of tax	(1)	—	—	—	(1)
Comprehensive loss	(124)	(13)	(24)	38	(123)
Less: Comprehensive income attributable to noncontrolling interest	—	—	1	—	1
Total comprehensive loss attributable to Dynegy Inc.	$(124)	$(13)	$ (25)	$ 38	$(124)

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Six Months Ended June 30, 2014

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$(164)	$ 16	$ (88)	$ 77	$(159)
Other comprehensive income (loss) before reclassifications:					
Actuarial loss, net of tax of zero	—	—	(3)	—	(3)
Amounts reclassified from accumulated other comprehensive income (loss):					
Amortization of unrecognized prior service cost and actuarial loss, net of tax of zero	(2)	—	—	—	(2)
Other comprehensive income (loss) from investment in affiliates	(3)	—	—	3	—
Other comprehensive income (loss), net of tax	(5)	—	(3)	3	(5)
Comprehensive income (loss)	(169)	16	(91)	80	(164)
Less: Comprehensive income (loss) attributable to noncontrolling interest	(1)	—	4	1	4
Total comprehensive income (loss) attributable to Dynegy Inc.	$(168)	$ 16	$ (95)	$ 79	$(168)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Condensed Consolidating Statements of Cash Flow for the Six Months Ended June 30, 2014
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$(30)	$ 181	$ 12	$—	$ 163
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(38)	(31)	—	(69)
Proceeds from asset sales, net	—	14	—	—	14
Net intercompany transfers	158	—	—	(158)	—
Net cash provided by (used in) investing activities	158	(24)	(31)	(158)	(55)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings, net of financing costs	(1)	12	—	—	11
Repayments of borrowings	(4)	—	—	—	(4)
Net intercompany transfers	—	(178)	20	158	—
Interest rate swap settlement payments	(9)	—	—	—	(9)
Other financing	(1)	—	—	—	(1)
Net cash provided by (used in) financing activities	(15)	(166)	20	158	(3)
Net increase (decrease) in cash and cash equivalents	113	(9)	1	—	105
Cash and cash equivalents, beginning of period	474	154	215	—	843
Cash and cash equivalents, end of period	$587	$ 145	$ 216	$—	$ 948

Note 16—Segment Information

We report the results of our operations in three segments: (i) Coal, (ii) IPH and (iii) Gas. The Coal segment includes DMG, which owns, directly and indirectly, certain of our coal-fired power generation facilities. The IPH segment includes IPGC or Genco, and Illinois Power Resources Generating, LLC (“IPRG”) which also owns, directly and indirectly, certain of our coal-fired power generation facilities. IPH also includes our Homefield Energy retail business in Illinois. IPH and its direct and indirect subsidiaries and Genco and its direct and indirect subsidiaries are each organized into ring-fenced groups in order to maintain corporate separateness from the Gas and Coal segments. The Gas segment includes DPC, which owns, directly or indirectly, certain of our wholly-owned natural gas-fired power generation facilities. Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). General and administrative expense is reported in Other for all periods presented.

Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the three and six months ended June 30, 2014 and 2013 is presented below:

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Segment Data as of and for the Three Months Ended June 30, 2014

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$136	$178	$207	$—	$521
Intercompany revenues	—	1	(1)	—	—
Total revenues	$136	$179	$206	$—	$521
Depreciation expense	$(11)	$(10)	$(35)	$(1)	$(57)
Gain on sale of assets, net	—	—	14	—	14
General and administrative expense	—	—	—	(29)	(29)
Operating loss	$(5)	$(17)	$(2)	$(30)	$(54)
Earnings from unconsolidated investments	—	—	10	—	10
Interest expense					(42)
Other items, net	—	—	—	(39)	(39)
Loss before income taxes					(125)
Income tax benefit					3
Net loss					(122)
Less: Net income attributable to noncontrolling interest					1
Net loss attributable to Dynegy Inc.					$(123)
Identifiable assets (domestic)	$1,164	$1,152	$2,157	$715	$5,188
Capital expenditures	$(8)	$(20)	$(23)	$(1)	$(52)

31

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Segment Data as of and for the Six Months Ended June 30, 2014

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$297	$381	$605	$—	$1,283
Intercompany revenues	(5)	2	3	—	—
Total revenues	$292	$383	$608	$—	$1,283
Depreciation expense	$(25)	$(18)	$(79)	$(2)	$(124)
Gain on sale of assets, net	—	—	14	—	14
General and administrative expense	—	—	—	(55)	(55)
Operating income (loss)	$4	$(33)	$32	$(56)	$(53)
Earnings from unconsolidated investments	—	—	10	—	10
Interest expense					(72)
Other items, net	—	—	—	(45)	(45)
Loss before income taxes					(160)
Income tax expense					1
Net loss					(159)
Less: Net income attributable to noncontrolling interest					5
Net loss attributable to Dynegy Inc.					$(164)
Identifiable assets (domestic)	$1,164	$1,152	$2,157	$715	$5,188
Capital expenditures	$(11)	$(31)	$(25)	$(2)	$(69)

32

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Segment Data as of and for the Three Months Ended June 30, 2013

(amounts in millions)	Coal	Gas	Other and Eliminations	Total
Domestic:				
Unaffiliated revenues	$114	$187	$—	$301
Intercompany revenues	1	(1)	—	—
Total revenues	$115	$186	$—	$301
Depreciation expense	$(10)	$(39)	$—	$(49)
Gain on sale of assets, net	1	—	—	1
General and administrative expense	—	—	(25)	(25)
Operating loss	$(49)	$(36)	$(26)	$(111)
Interest expense				(16)
Loss on extinguishment of debt				(12)
Other items, net	—	(1)	(10)	(11)
Loss from continuing operations before income taxes				(150)
Income tax benefit				—
Loss from continuing operations				(150)
Income from discontinued operations, net of tax				5
Net loss				$(145)
Identifiable assets (domestic)	$1,214	$2,378	$561	$4,153
Capital expenditures	$(19)	$(15)	$(1)	$(35)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2014 and 2013

Segment Data as of and for the Six Months Ended June 30, 2013

(amounts in millions)	Coal	Gas	Other and Eliminations	Total
Domestic:				
Unaffiliated revenues	$201	$418	$—	$619
Intercompany revenues	1	(1)	—	—
Total revenues	$202	$417	$—	$619
Depreciation expense	$(23)	$(79)	$(1)	$(103)
Gain on sale of assets, net	2	—	—	2
General and administrative expense	—	—	(47)	(47)
Operating loss	$(129)	$(44)	$(53)	$(226)
Interest expense				(45)
Loss on extinguishment of debt				(11)
Other items, net	—	—	(10)	(10)
Loss from continuing operations before income taxes				(292)
Income tax benefit				—
Loss from continuing operations				(292)
Income from discontinued operations, net of tax				5
Net loss				$(287)
Identifiable assets (domestic)	$1,214	$2,378	$561	$4,153
Capital expenditures	$(31)	$(23)	$(1)	$(55)

DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended June 30, 2014 and 2013
Item 2—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

We are 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 separate segments in our unaudited consolidated financial statements: (i) the Coal segment ("Coal"), (ii) the IPH segment ("IPH") and (iii) the Gas segment ("Gas").

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, fixed capacity payments and contractual obligations, capital expenditures (including required environmental expenditures) and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated margin and collateral requirements, facility maintenance costs and other costs such as payroll. Our primary sources of liquidity are cash flows from operations, cash on hand and amounts available under the revolver.

IPH and its direct and indirect subsidiaries are organized into ring-fenced groups in order to maintain corporate separateness from Dynegy and our other legal entities. Certain of the entities in the IPH segment, including Genco, have an independent director whose consent is required for certain corporate actions, including material transactions with affiliates. Further, entities within the IPH segment present themselves to the public as separate entities. They maintain separate books, records and bank accounts and separately appoint officers. Furthermore, they pay liabilities from their own funds, conduct business in their own names and have restrictions on pledging their assets for the benefit of certain other persons. These provisions restrict our ability to move cash out of these entities without meeting certain requirements as set forth in the governing documents.

On June 27, 2014, we completed the sale of our 50 percent partnership interest in Nevada Cogeneration Associates #2, a partnership that owns Black Mountain, an 85 MW (43 net MW) natural gas-fired combined cycle gas turbine facility in Nevada. We received $14 million in cash proceeds upon the close of the transaction. Additionally, we received $10 million in cash distributions from Black Mountain. Please read Note 3—Acquisition and Divestitures for further discussion.

The following table summarizes our liquidity position at June 30, 2014:

	June 30, 2014		
(amounts in millions)	Dynegy Inc.	IPH (1) (2)	Total
Revolver capacity	$475	$—	$475
Less: Outstanding letters of credit	(181)	—	(181)
Revolver availability	294	—	294
Cash and cash equivalents	732	216	948
Total available liquidity (3)	$1,026	$216	$1,242

(1) Includes Cash and cash equivalents of $182 million related to Genco.

(2) As previously discussed, due to the ring-fenced nature of IPH, cash at the IPH and Genco entities may not be moved out of these entities without meeting certain criteria. However, cash at these entities is available to support current operations of these entities.

35

Table of Contents

(3) On December 2, 2013, Dynegy and IPR entered into an intercompany revolving promissory note of $25 million. At June 30, 2014, there was $12 million outstanding on the note.

Operating Activities

Historical Operating Cash Flows. Cash flow provided by operations totaled $163 million for the six months ended June 30, 2014. During the period, our power generation business provided cash of $223 million primarily due to the operation of our power generation facilities. Corporate and other activities used cash of approximately $89 million primarily due to interest payments related to our Credit Agreement and Senior Notes of approximately $36 million, interest payments on the Genco Senior Notes of approximately $29 million and other general and administrative expense of $24 million. In addition, we had $29 million in positive changes in working capital, which includes $5 million of increased collateral postings to satisfy our counterparty collateral demands.

Cash flow used in operations totaled $10 million for the six months ended June 30, 2013. During the period, our power generation business provided cash of $9 million primarily due to the operation of our power generation business. Corporate and other operations used cash of approximately $12 million primarily due to interest payments related to our Credit Agreement and Senior Notes, payments for acquisition and integration costs, payments for bankruptcy reorganization expenses, employee-related payments and other general and administrative expense. In addition, we had $7 million in negative changes in working capital, including $2 million of increased collateral postings to satisfy our counterparty collateral demands.

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, and our ability to achieve the cost savings contemplated in our PRIDE initiative.

Collateral Postings. We use a portion of our capital resources in the form of cash and letters of credit to satisfy counterparty collateral demands. The following table summarizes our collateral postings to third parties by legal entity at June 30, 2014 and December 31, 2013:

(amounts in millions)	June 30, 2014	December 31, 2013
Dynegy Inc.:		
Cash (1)	$25	$22
Letters of credit	181	157
Total Dynegy Inc.	206	179
IPH:		
Cash (1) (2)	9	7
Letters of credit (3)	10	—
Total IPH	19	7
Total	$225	$186

---

(1) Includes broker margin as well as other collateral postings included in Prepayments and other current assets on our unaudited consolidated balance sheets. At June 30, 2014 and December 31, 2013, $8 million and $4 million of cash posted as collateral were netted against Liabilities from risk management activities on our unaudited consolidated balance sheets, respectively.

(2) Includes cash of $5 million and $1 million related to Genco at June 30, 2014 and December 31, 2013, respectively.

(3) Relates to the $25 million cash-backed LC facility at IPM.

In addition to cash and letters of credit posted as collateral, we have granted additional permitted first priority liens on assets already subject to first priority liens under our former and new credit agreements. The additional liens were granted as collateral under certain of our 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.

36

Table of Contents

Collateral postings increased from December 31, 2013 to June 30, 2014 primarily due to new transactions and mark-to-market changes for fuel and other commodity purchases being executed with counterparties, ISO postings in support of our retail energy business and overall changes in our commercial activity.
The fair value of our derivatives collateralized by first priority liens included liabilities of $211 million and $145 million at June 30, 2014 and December 31, 2013, 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 potential collateral requirements of such instruments.
Investing Activities
Capital Expenditures. We had capital expenditures of approximately $69 million and $55 million during the six months ended June 30, 2014 and 2013, respectively. These amounts include capitalized interest of $10 million and zero for the six months ended June 30, 2014 and 2013, respectively. Our capital spending by reportable segment was as follows:

(amounts in millions)	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Coal	$11	$31
IPH	31	—
Gas	25	23
Other	2	1
Total	$69	$55

Other Investing Activities. During the six months ended June 30, 2014, there was a $14 million cash inflow related to cash proceeds received upon the close of the sale of our 50 percent partnership interest in Nevada Cogeneration Associates #2, a partnership that owns Black Mountain. Please read Note 3—Acquisition and Divestitures for further discussion.
During the six months ended June 30, 2013, there was a $335 million cash inflow related to restricted cash balances related to the release of unused cash collateral associated with the DPC LC and DMG LC facilities. A portion of these proceeds were used to repay in full and terminate commitments under the DMG and DPC credit agreements as further discussed below. As a result of repaying these credit agreements, all of our restricted cash was released.
Financing Activities
Historical Cash Flow from Financing Activities. Cash flow used in financing activities totaled $3 million for the six months ended June 30, 2014 due primarily to $9 million in interest rate swap settlement payments, $4 million in principal payments of borrowings on the Tranche B-2 Term Loan and $1 million in financing costs in connection with the Credit Agreement and Senior Notes, offset by $12 million in proceeds received related to the Emissions Repurchase Agreement. Please read Note 9—Debt for further discussion.
Cash flow used in financing activities totaled $160 million for the six months ended June 30, 2013 due to $1,913 million in repayments of borrowings in full on the DMG and DPC credit agreements and the Tranche B-1 Term Loan, including $59 million in prepayment penalties associated with the early termination of the DMG and DPC credit agreements, offset by $1,753 million in proceeds from borrowings on the Credit Agreement and Senior Notes, net of financing costs.
Financing Trigger Events. Our debt instruments and certain of our other financial obligations and all the Genco Senior Notes include provisions which, if not met, could require early payment, additional collateral support or similar actions. The trigger events include the violation of covenants (including, in the case of the Credit Agreement under certain circumstances, the senior secured leverage ratio covenant discussed below), 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, in the case of the Credit Agreement, change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events.

Table of Contents

Financial Covenants

Credit Agreement. On April 23, 2013, we entered into the Credit Agreement. The Credit Agreement contains customary events of default and affirmative and negative covenants, subject to certain specified exceptions, including a financial covenant specifying required thresholds for our senior secured leverage ratio calculated on a rolling four quarters basis. Under the Credit Agreement, if Dynegy has utilized 25 percent or more of its Revolving Facility, Dynegy must be in compliance with the following ratios for the respective periods:

Compliance Period	Consolidated Senior Secured Net Debt to Consolidated Adjusted EBITDA (1)
September 30, 2013 through December 31, 2013	5.00: 1.00
March 31, 2014 through December 31, 2014	4.00: 1.00
March 31, 2015 through December 31, 2015	4.75: 1.00
March 31, 2016 through December 31, 2016	3.75: 1.00
March 31, 2017 and Thereafter	3.00: 1.00

(1) For purposes of calculating Net Debt, we may only apply a maximum of $150 million in cash to our outstanding secured debt.

Our revolver usage at June 30, 2014 was 38 percent of the aggregate revolver commitment due to outstanding letters of credit; therefore, we were required to test the covenant. Based on the calculation outlined in the Credit Agreement, we are in compliance at June 30, 2014.

Genco Senior Notes. On December 2, 2013, in connection with the AER Acquisition, Genco Senior Notes remained outstanding as an obligation of Genco, a subsidiary of IPH. Genco’s indenture includes provisions that require Genco to maintain certain interest coverage and debt-to-capital ratios in order for Genco to pay dividends, to make principal or interest payments on subordinated borrowings, to make loans to or investments in affiliates or to incur additional external, third-party indebtedness.

The following table summarizes these required ratios:

	Required Ratio
Restricted payment interest coverage ratio (1)	≥1.75
Additional indebtedness interest coverage ratio (2)	≥2.50
Additional indebtedness debt-to-capital ratio (2)	≤60%

(1) As of the date of a restricted payment, as defined, the minimum ratio must have been achieved for the most recently ended four fiscal quarters and projected by management to be achieved for each of the subsequent four six-month periods.

(2) Ratios must be computed on a pro forma basis considering the additional indebtedness to be incurred and the related interest expense. Other borrowings from third-party external sources are included in the definition of indebtedness and are subject to these incurrence tests.

Genco’s debt incurrence-related ratio restrictions under the indenture may be disregarded if both Moody’s and S&P reaffirm the ratings in place at the time of the debt incurrence after considering the additional indebtedness.

Based on June 30, 2014 calculations, Genco’s interest coverage ratios are less than the minimum ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources. Based on our projections, we expect that Genco’s interest coverage ratios will be less than the minimum ratios required for Genco to pay dividends and incur additional third-party indebtedness until at least 2016.

Please read Note 9—Debt for further discussion.

Table of Contents

Credit Ratings

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

	Moody's	S&P
Dynegy Inc.:		
Corporate Family Rating	B2	B
Senior Secured	B1	BB-
Senior Unsecured	B3	B+
Genco:		
Senior Unsecured	B3	CCC+

Table of Contents

RESULTS OF OPERATIONS

Overview

In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three and six months ended June 30, 2014 and 2013. At the end of this section, we have included our business outlook for each segment.

We report the results of our power generation business primarily as three separate segments in our unaudited consolidated financial statements: (i) Coal, (ii) IPH and (iii) Gas. Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). General and administrative expense is reported in Other for all periods presented.

Consolidated Summary Financial Information — Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

The following table provides summary financial data regarding our consolidated results of operations for the three months ended June 30, 2014 and 2013, respectively:

(amounts in millions)	Three Months Ended June 30, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues	$521	$301	$ 220	73 %
Cost of sales, excluding depreciation expense	(365)	(253)	(112)	(44)%
Gross margin	156	48	108	225 %
Operating and maintenance expense	(136)	(85)	(51)	(60)%
Depreciation expense	(57)	(49)	(8)	(16)%
Gain on sale of assets, net	14	1	13	1,300 %
General and administrative expense	(29)	(25)	(4)	(16)%
Acquisition and integration costs	(2)	(1)	(1)	(100)%
Operating loss	(54)	(111)	57	51 %
Earnings from unconsolidated investments	10	—	10	100 %
Interest expense	(42)	(16)	(26)	(163)%
Loss on extinguishment of debt	—	(12)	12	100 %
Other income and expense, net	(39)	(11)	(28)	(255)%
Loss from continuing operations before income taxes	(125)	(150)	25	17 %
Income tax benefit	3	—	3	100 %
Loss from continuing operations	(122)	(150)	28	19 %
Income from discontinued operations, net of tax	—	5	(5)	(100)%
Net loss	(122)	(145)	23	16 %
Less: Net income attributable to noncontrolling interest	1	—	1	100 %
Net loss attributable to Dynegy Inc.	$(123)	$(145)	$ 22	15 %

Table of Contents

The following tables provide summary financial data regarding our operating loss by segment for the three months ended June 30, 2014 and 2013, respectively:

	Three Months Ended June 30, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$136	$179	$206	$—	$521
Cost of sales, excluding depreciation expense	(89)	(130)	(146)	—	(365)
Gross margin	47	49	60	—	156
Operating and maintenance expense	(41)	(54)	(41)	—	(136)
Depreciation expense	(11)	(10)	(35)	(1)	(57)
Gain on sale of assets, net	—	—	14	—	14
General and administrative expense	—	—	—	(29)	(29)
Acquisition and integration costs (1)	—	(2)	—	—	(2)
Operating loss	$(5)	$(17)	$(2)	$(30)	$(54)

	Three Months Ended June 30, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$115	$186	$—	$301
Cost of sales, excluding depreciation expense	(103)	(150)	—	(253)
Gross margin	12	36	—	48
Operating and maintenance expense	(52)	(33)	—	(85)
Depreciation expense	(10)	(39)	—	(49)
Gain on sale of assets, net	1	—	—	1
General and administrative expense	—	—	(25)	(25)
Acquisition and integration costs (1)(2)	—	—	(1)	(1)
Operating loss	$(49)	$(36)	$(26)	$(111)

---

(1) Relates to costs associated with the AER Transaction Agreement. Please read Note 3—Acquisition and Divestitures for further discussion.

(2) Acquisition and integration costs were captured in the Other segment prior to the closing of the AER Acquisition.

Discussion of Consolidated Results of Operations

Revenues. Revenues increased by $220 million from $301 million for the three months ended June 30, 2013 to $521 million for the three months ended June 30, 2014. Coal segment revenues increased by $21 million driven largely by higher realized prices and generation volumes in 2014. IPH segment revenues increased by $179 million on 5.4 million MWh of power generation from zero in the comparable period due to the AER Acquisition. Gas segment revenues increased by $20 million driven largely by higher spark spreads and generation volumes primarily at Independence, Ontelaunee and Casco Bay in 2014.

Cost of Sales. Cost of sales increased by $112 million from $253 million for the three months ended June 30, 2013 to $365 million for the three months ended June 30, 2014. Coal segment cost of sales decreased $14 million primarily due to $32 million in lower amortization costs associated with rail transportation contracts recorded in connection with the application of fresh-start accounting on the effective date of the Plan, partially offset by higher volumes and coal transportation costs due to a contracted price increase. IPH segment cost of sales increased by $130 million from zero in the comparable period due to the AER Acquisition. Gas segment cost of sales decreased $4 million driven by lower purchased and resold volumes than in 2013 partially offset by higher volumes and natural gas pricing in 2014.

Operating and Maintenance Expense. Operating and maintenance expense increased by $51 million from $85 million for the three months ended June 30, 2013 to $136 million for the three months ended June 30, 2014. The increase was primarily due to IPH segment costs of $54 million as a result of the AER Acquisition and an $8 million increase in Gas segment costs, partially offset by $11 million in lower Coal segment costs primarily due to fewer planned outages during the three months ended June 30, 2014 compared to the three months ended June 30, 2013.

Table of Contents

Depreciation Expense. Depreciation expense increased by $8 million from $49 million for the three months ended June 30, 2013 to $57 million for the three months ended June 30, 2014. The increase in depreciation expense was primarily related to a $10 million increase in the IPH segment as the result of the AER Acquisition, partially offset by a $4 million decrease in the Gas segment due to various equipment retirements in the first quarter 2014.

Gain on Sale of Assets. Gain on sale of assets increased by $13 million from $1 million for the three months ended June 30, 2013 to $14 million for the three months ended June 30, 2014. This increase was primarily due to the sale of our 50 percent partnership interest in Nevada Cogeneration Associates #2, a partnership that owns Black Mountain. Please read Note 3—Acquisition and Divestitures for further discussion.

General and Administrative Expense. General and administrative expense increased by $4 million from $25 million for the three months ended June 30, 2013 to $29 million for the three months ended June 30, 2014. This increase was primarily due to $1 million in higher labor and benefit costs associated with the AER Acquisition, a $1 million increase in stock compensation expense and $2 million in higher legal fees.

Acquisition and Integration Costs. Acquisition and integration costs increased by $1 million from $1 million for the three months ended June 30, 2013 to $2 million for the three months ended June 30, 2014 primarily related to the continued integration of the AER Acquisition. Please read Note 3—Acquisition and Divestitures for further discussion.

Earnings from Unconsolidated Investments. Earnings from unconsolidated investments were $10 million for the three months ended June 30, 2014 due to cash distributions received from Black Mountain. There was no similar activity during the three months ended June 30, 2013. Please read Note 3—Acquisition and Divestitures for further discussion.

Interest Expense. Interest expense increased by $26 million from $16 million for the three months ended June 30, 2013 to $42 million for the three months ended June 30, 2014. This increase was primarily due to $15 million in interest related to the Genco Senior Notes as a result of the AER Acquisition and $13 million in mark-to-market losses on interest rate swaps. Please read Note 9—Debt for further discussion.

Loss on Extinguishment of Debt. Loss on extinguishment of debt totaled $12 million for the three months ended June 30, 2013 and was incurred in connection with the termination of the DPC and DMG credit agreements and the Term Loan B-1. The amount is comprised of (i) a prepayment penalty of approximately $59 million, (ii) $2 million for the accelerated amortization of the discount on the Term Loan B-1 and (iii) $6 million in accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Term Loan B-1, offset by (iv) $55 million in non-cash gains net for the accelerated amortization of the remaining premium related to the DPC and the DMG credit agreements. There was no similar activity during the three months ended June 30, 2014. Please read Note 12—Debt in our Form 10-K for further discussion.

Other Income and Expense, net. Other income and expense, net increased by $28 million from expense of $11 million for the three months ended June 30, 2013 to expense of $39 million for the three months ended June 30, 2014. The increase in other income and expense, net was primarily due to the change in the fair value of our common stock warrants during the three months ended June 30, 2014 compared to the three months ended June 30, 2013.

Income Tax Benefit. We reported an income tax benefit from continuing operations of $3 million and zero for the three months ended June 30, 2014 and June 30, 2013, respectively.

For the three months ended June 30, 2014 and 2013, the difference between the effective rate of two percent and zero percent, respectively, and the statutory rate of 35 percent resulted primarily from a valuation allowance against our net deferred tax assets and a change in our expected alternative minimum tax for the 2014 tax year. As of June 30, 2014 and 2013, we did not believe we would produce sufficient future taxable income, nor were there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

Income from Discontinued Operations. For the three months ended June 30, 2013, income from discontinued operations was $5 million and primarily consisted of a $7 million DNE pension curtailment gain due to the termination of a majority of the Danskammer employees and closing of the Roseton sale, partially offset by a $2 million loss related to legacy capacity contracts executed with the Roseton facility which terminated upon the sale of the facility. There was no similar activity during the three months ended June 30, 2014. Please read Note 3—Acquisition and Divestitures for further discussion.

Net Income Attributable to Noncontrolling Interest. For the three months ended June 30, 2014, net income attributable to noncontrolling interest was $1 million related to the minority shareholder's 20 percent interest in EEI.

Discussion of Adjusted EBITDA

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

Table of Contents

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 certain assets, (ii) the impacts of mark-to-market changes on derivatives related to our generation portfolio, as well as interest rate swaps and warrants, (iii) the impact of impairment charges and certain other costs such as those associated with the acquisition of AER, (iv) income or expense on up front premiums received or paid for financial options in periods other than the strike periods and (v) income or losses attributable to noncontrolling interest.

We believe EBITDA and Adjusted EBITDA provide meaningful representations 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 entire power generation fleet for the period presented; consequently, it excludes the impact of mark-to-market accounting, impairment charges, gains and losses on sales of assets, and other items that could be considered "non-operating" or "non-core" in nature. 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). Management does not analyze interest expense and income taxes on a segment level; therefore, the most directly comparable GAAP financial measure to Adjusted EBITDA when performance is discussed on a segment level is Operating income (loss).

Table of Contents

Adjusted EBITDA — Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2014:

	Three Months Ended June 30, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(123)
Income attributable to noncontrolling interest					1
Income tax benefit					(3)
Interest expense					42
Earnings from unconsolidated investments					(10)
Other items, net					39
Operating loss	$(5)	$(17)	$(2)	$(30)	$(54)
Depreciation expense	11	10	35	1	57
Amortization of intangible assets and liabilities, net	(2)	3	18	—	19
Earnings from unconsolidated investments	—	—	10	—	10
Other items, net	—	—	—	(39)	(39)
EBITDA	4	(4)	61	(68)	(7)
Acquisition and integration costs	—	2	—	—	2
Mark-to-market loss, net	—	4	10	—	14
Change in fair value of common stock warrants	—	—	—	43	43
Gain on sale of assets, net	—	—	(14)	—	(14)
Income attributable to noncontrolling interest	—	(1)	—	—	(1)
Other	4	(1)	1	(3)	1
Adjusted EBITDA	$8	$—	$58	$(28)	$38

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2013:

	Three Months Ended June 30, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(145)
Income from discontinued operations, net of tax				(5)
Loss on extinguishment of debt				12
Interest expense				16
Other items, net				11
Operating loss	$(49)	$(36)	$(26)	$(111)
Depreciation expense	10	39	—	49
Amortization of intangible assets and liabilities, net	33	31	—	64
Other items, net	—	(1)	(10)	(11)
EBITDA	(6)	33	(36)	(9)
Acquisition and integration costs	—	—	1	1
Mark-to-market (income) loss, net	(18)	19	—	1
Change in fair value of common stock warrants	—	—	9	9
Other	—	1	5	6
Adjusted EBITDA	$(24)	$53	$(21)	$8

Table of Contents

Adjusted EBITDA increased by $30 million from $8 million for the three months ended June 30, 2013 to $38 million for the three months ended June 30, 2014. The increase was primarily due to improved realized energy prices in the Coal segment and improved spark spreads in the Gas segment. See Discussion of Segment Adjusted EBITDA for further information.

Table of Contents

Discussion of Segment Adjusted EBITDA — Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the three months ended June 30, 2014 and 2013, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$157	$112	$ 45	40 %
Capacity	1	1	—	— %
Mark-to-market income, net	—	18	(18)	(100)%
Other (1)	(22)	(16)	(6)	(38)%
Total operating revenues	136	115	21	18 %
Operating Costs				
Cost of sales	(91)	(70)	(21)	(30)%
Contract amortization	2	(33)	35	106 %
Total operating costs	(89)	(103)	14	14 %
Gross margin	47	12	35	292 %
Operating and maintenance expense	(41)	(52)	11	21 %
Depreciation expense	(11)	(10)	(1)	(10)%
Gain on sale of assets, net	—	1	(1)	(100)%
Operating loss	(5)	(49)	44	90 %
Depreciation expense	11	10	1	10 %
Amortization of intangible assets and liabilities, net	(2)	33	(35)	(106)%
EBITDA	4	(6)	10	167 %
Mark-to-market income, net	—	(18)	18	100 %
Other	4	—	4	100 %
Adjusted EBITDA	$8	$(24)	$ 32	133 %
Million Megawatt Hours Generated	4.6	4.4	0.2	5 %
In Market Availability for Coal-Fired Facilities (2)	92 %	91 %		
Average Capacity Factor for Coal-Fired Facilities (3)	71 %	67 %		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$45.28	$41.76	$ 3.52	8 %
Off-Peak: Indiana (Indy Hub)	$30.37	$28.90	$ 1.47	5 %

(1) For the three months ended June 30, 2014 and 2013, respectively, Other includes ($23) million and ($14) million in financial settlements, $1 million and $1 million in ancillary services and zero and ($3) million in other miscellaneous items.

(2) In Market Availability is an internal measurement calculation that reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.

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

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

46

Table of Contents

Operating loss for the three months ended June 30, 2014 was $5 million compared to $49 million for the three months ended June 30, 2013. Adjusted EBITDA was income of $8 million during the three months ended June 30, 2014 compared to a loss of $24 million during the same period in 2013. The $32 million increase in Adjusted EBITDA resulted from higher realized prices in the three months ended June 30, 2014 compared to the three months ended June 30, 2013. During the period, LMP prices increased $40 million and the percentage of the fleet that was hedged declined further enhancing the impact of rising prices. The benefit associated with higher realized prices, together with a reduction in operating and maintenance expense of $11 million due to fewer planned outages more than offset an increase in hedge losses of $9 million and higher delivered fuel costs of $14 million primarily due to the new rail transport agreement.

Table of Contents

IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the three months ended June 30, 2014:

(dollars in millions, except for price information)	Three Months Ended June 30, 2014	
Operating Revenues		
Energy	$ 190	
Capacity	12	
Mark-to-market loss, net	(4	)
Contract amortization	(12	)
Other (1)	(7	)
Total operating revenues	179	
Operating Costs		
Cost of sales	(139	)
Contract amortization	9	
Total operating costs	(130	)
Gross margin	49	
Operating and maintenance expense	(54	)
Depreciation expense	(10	)
Acquisition and integration costs	(2	)
Operating loss	(17	)
Depreciation expense	10	
Amortization of intangible assets and liabilities, net	3	
EBITDA	(4	)
Mark-to-market loss, net	4	
Acquisition and integration costs	2	
Income attributable to noncontrolling interest	(1	)
Other	(1	)
Adjusted EBITDA	$ —	
Million Megawatt Hours Generated	5.4	
In Market Availability for IPH Facilities (2)	86	%
Average Capacity Factor for IPH Facilities (3)	59	%
Average Quoted Market Power Prices ($/MWh) (4):		
On-Peak: Indiana (Indy Hub)	$ 45.28	
Off-Peak: Indiana (Indy Hub)	$ 30.37	

(1) For the three months ended June 30, 2014, Other includes $1 million in financial settlements, ($5) million in ancillary services and ($3) million in other miscellaneous items.

(2) In Market Availability is an internal measurement calculation that reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.

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

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

Operating loss for the three months ended June 30, 2014 was $17 million. IPH contributed no Adjusted EBITDA during the three months ended June 30, 2014. IPH generated 5.4 million MWh, a meaningful portion of which was hedged through the

Table of Contents

retail business and other third parties. During the three months ended June 30, 2014, the capacity factor was 59 percent due to planned and unplanned outages as well as unfavorable market conditions which adversely impacted results.

Table of Contents

Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the three months ended June 30, 2014 and 2013, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$155	$132	$ 23	17 %
Capacity	61	56	5	9 %
Mark-to-market loss, net	(10)	(17)	7	41 %
Contract amortization	(20)	(33)	13	39 %
Other (1)	20	48	(28)	(58)%
Total operating revenues	206	186	20	11 %
Operating Costs				
Cost of sales	(148)	(152)	4	3 %
Contract amortization	2	2	—	— %
Total operating costs	(146)	(150)	4	3 %
Gross margin	60	36	24	67 %
Operating and maintenance expense	(41)	(33)	(8)	(24)%
Depreciation expense	(35)	(39)	4	10 %
Gain on sale of assets, net	14	—	14	100 %
Operating loss	(2)	(36)	34	94 %
Depreciation expense	35	39	(4)	(10)%
Amortization of intangible assets and liabilities, net	18	31	(13)	(42)%
Earnings from unconsolidated investments	10	—	10	100 %
Other items, net	—	(1)	1	100 %
EBITDA	61	33	28	85 %
Mark-to-market loss, net	10	19	(9)	(47)%
Gain on sale of assets, net	(14)	—	(14)	(100)%
Other	1	1	—	— %
Adjusted EBITDA	$58	$53	$ 5	9 %
Million Megawatt Hours Generated (2)	3.7	3.5	0.2	6 %
In Market Availability for Combined Cycle Facilities (3)	97 %	96 %		
Average Capacity Factor for Combined Cycle Facilities (4)	39 %	37 %		
Average Market On-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$12.23	$11.33	$ 0.90	8 %
PJM West	$25.16	$17.45	$ 7.71	44 %
North of Path 15 (NP 15)	$11.93	$13.44	$ (1.51)	(11)%
New York—Zone A	$15.74	$11.69	$ 4.05	35 %
Mass Hub	$15.97	$13.37	$ 2.60	19 %
Average Market Off-Peak Spark Spreads ($/MWh) (5):				

Commonwealth Edison (NI Hub)	$(5.36)	$(1.37)	$ (3.99)	(291)%
PJM West	$7.89	$3.51	$ 4.38	125 %
North of Path 15 (NP 15)	$0.72	$4.01	$ (3.29)	(82)%
New York—Zone A	$1.16	$0.75	$ 0.41	55 %
Mass Hub	$2.87	$2.63	$ 0.24	9 %
Average natural gas price—Henry Hub ($/MMBtu) (6)	$4.58	$4.01	$ 0.57	14 %

50

Table of Contents

(1) For the three months ended June 30, 2014 and 2013, respectively, Other includes $1 million and ($5) million in financial settlements, $9 million and $26 million in natural gas sales, $7 million and $7 million in ancillary services, $2 million and $17 million in tolls and $1 million and $3 million in RMR, option premiums and other miscellaneous items.

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

(3) In Market Availability is an internal measurement calculation that reflects the percentage of generation available when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.

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

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

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

Operating loss for the three months ended June 30, 2014 was $2 million compared to $36 million for the three months ended June 30, 2013. Adjusted EBITDA totaled $58 million during the three months ended June 30, 2014 compared to $53 million during the same period in 2013. The $5 million increase in Adjusted EBITDA primarily resulted from higher energy margin due to increased generation volumes and higher spark spreads primarily at Independence, Ontelaunee and Casco Bay, capacity revenues primarily at Kendall and Ontelaunee and distributions from Black Mountain in the three months ended June 30, 2014 as compared to the same period in 2013. This increase was partially offset by a decrease in revenues associated with the Moss Landing toll and an increase in operating and maintenance expense.

Table of Contents

Consolidated Summary Financial Information — Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The following table provides summary financial data regarding our consolidated results of operations for the six months ended June 30, 2014 and 2013, respectively:

(amounts in millions)	Six Months Ended June 30, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues	$1,283	$619	$ 664	107 %
Cost of sales, excluding depreciation expense	(917)	(537)	(380)	(71)%
Gross margin	366	82	284	346 %
Operating and maintenance expense	(246)	(156)	(90)	(58)%
Depreciation expense	(124)	(103)	(21)	(20)%
Gain on sale of assets, net	14	2	12	600 %
General and administrative expense	(55)	(47)	(8)	(17)%
Acquisition and integration costs	(8)	(4)	(4)	(100)%
Operating loss	(53)	(226)	173	77 %
Earnings from unconsolidated investments	10	—	10	100 %
Interest expense	(72)	(45)	(27)	(60)%
Loss on extinguishment of debt	—	(11)	11	100 %
Other income and expense, net	(45)	(10)	(35)	(350)%
Loss before income taxes	(160)	(292)	132	45 %
Income tax benefit	1	—	1	100 %
Loss from continuing operations	(159)	(292)	133	46 %
Income from discontinued operations, net of tax	—	5	(5)	(100)%
Net loss	(159)	(287)	128	45 %
Less: Net income attributable to noncontrolling interest	5	—	5	100 %
Net loss attributable to Dynegy Inc.	$(164)	$(287)	$ 123	43 %

The following tables provide summary financial data regarding our operating income (loss) by segment for the six months ended June 30, 2014 and 2013, respectively:

	Six Months Ended June 30, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$292	$383	$608	$—	$1,283
Cost of sales, excluding depreciation expense	(185)	(289)	(443)	—	(917)
Gross margin	107	94	165	—	366
Operating and maintenance expense	(78)	(101)	(68)	1	(246)
Depreciation expense	(25)	(18)	(79)	(2)	(124)
Gain on sale of assets, net	—	—	14	—	14
General and administrative expense	—	—	—	(55)	(55)
Acquisition and integration costs (1)	—	(8)	—	—	(8)
Operating income (loss)	$4	$(33)	$32	$(56)	$(53)

52

Table of Contents

	Six Months Ended June 30, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$202	$417	$—	$619
Cost of sales, excluding depreciation expense	(218)	(319)	—	(537)
Gross margin	(16)	98	—	82
Operating and maintenance expense	(92)	(63)	(1)	(156)
Depreciation expense	(23)	(79)	(1)	(103)
Gain on sale of assets, net	2	—	—	2
General and administrative expense	—	—	(47)	(47)
Acquisition and integration costs (1)(2)	—	—	(4)	(4)
Operating loss	$(129)	$(44)	$(53)	$(226)

(1) Relates to costs associated with the AER Transaction Agreement. Please read Note 3—Acquisition and Divestitures for further discussion.

(2) Acquisition and integration costs were captured in the Other segment prior to the closing of the AER Acquisition.

Discussion of Consolidated Results of Operations

Revenues. Revenues increased by $664 million from $619 million for the six months ended June 30, 2013 to $1,283 million for the six months ended June 30, 2014. Coal segment revenues increased by $90 million driven largely by higher realized prices and generation volumes in 2014. IPH segment revenues increased by $383 million on 12.1 million MWh of power generation from zero in the comparable period due to the AER Acquisition. Gas segment revenues increased by $191 million driven largely by higher spark spreads and generation volumes primarily at Independence, Ontelaunee and Casco Bay in 2014, partially offset by a decrease in revenues associated with the Moss Landing toll.

Cost of Sales. Cost of sales increased by $380 million from $537 million for the six months ended June 30, 2013 to $917 million for the six months ended June 30, 2014. Coal segment cost of sales decreased by $33 million primarily due to $63 million in lower amortization costs associated with rail transportation contracts recorded in connection with the application of fresh-start accounting on the effective date of the Plan, partially offset by higher coal transportation costs due to a contracted price increase. IPH segment cost of sales was $289 million due to the AER Acquisition. Gas segment cost of sales increased by $124 million driven by higher natural gas pricing and volumes in 2014.

Operating and Maintenance Expense. Operating and maintenance expense increased by $90 million from $156 million for the six months ended June 30, 2013 to $246 million for the six months ended June 30, 2014. The increase was primarily due to IPH segment costs of $101 million as a result of the AER Acquisition, partially offset by $14 million in lower Coal segment costs primarily due to fewer planned outages during the six months ended June 30, 2014 compared to the the six months ended June 30, 2013.

Depreciation Expense. Depreciation expense increased by $21 million from $103 million for the six months ended June 30, 2013 to $124 million for the six months ended June 30, 2014. The increase in depreciation expense was primarily related to an $18 million increase in the IPH segment as the result of the AER Acquisition.

Gain on Sale of Assets. Gain on sale of assets increased by $12 million from $2 million for the six months ended June 30, 2013 to $14 million for the six months ended June 30, 2014. This increase was primarily due to the sale of our 50 percent partnership interest in Nevada Cogeneration Associates #2, a partnership that owns Black Mountain. Please read Note 3—Acquisition and Divestitures for further discussion.

General and Administrative Expense. General and administrative expense increased by $8 million from $47 million for the six months ended June 30, 2013 to $55 million for the six months ended June 30, 2014. This increase was primarily due to $2 million in higher labor and benefit costs associated with the AER Acquisition, a $2 million increase in stock compensation expense and $2 million in higher legal fees.

53

Table of Contents

Acquisition and Integration Costs. Acquisition and integration costs increased by $4 million from $4 million for the six months ended June 30, 2013 to $8 million for the six months ended June 30, 2014 and was primarily related to the continued integration of the AER Acquisition. Please read Note 3—Acquisition and Divestitures for further discussion.

Earnings from Unconsolidated Investments. Earnings from unconsolidated investments were $10 million for the six months ended June 30, 2014 due to cash distributions received from Black Mountain. There was no similar activity during the six months ended June 30, 2013. Please read Note 3—Acquisition and Divestitures for further discussion.

Interest Expense. Interest expense increased by $27 million from $45 million for the six months ended June 30, 2013 to $72 million for the six months ended June 30, 2014. This increase was primarily due to $30 million in interest related to the Genco Senior Notes as a result of the AER Acquisition and $10 million in mark-to-market losses on interest rate swaps, offset by $10 million in capitalized interest in 2014. Please read Note 9—Debt for further discussion.

Loss on Extinguishment of Debt. Loss on extinguishment of debt totaled $11 million for the six months ended June 30, 2013 and was incurred in connection with the termination of the DPC and DMG credit agreements and the Term Loan B-1. The amount is comprised of (i) a prepayment penalty of approximately $59 million, (ii) $2 million for the accelerated amortization of the discount on the Term Loan B-1 and (iii) $6 million in accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Term Loan B-1, offset by (iv) $56 million in non-cash gains net for the accelerated amortization of the remaining premium related to the DPC and the DMG credit agreements. There was no similar activity during the six months ended June 30, 2014. Please read Note 12—Debt in our Form 10-K for further discussion.

Other Income and Expense, net. Other income and expense, net increased by $35 million from expense of $10 million for the six months ended June 30, 2013 to expense of $45 million for the six months ended June 30, 2014. The increase in other income and expense, net was primarily due to the change in the fair value of our common stock warrants during the six months ended June 30, 2014 compared to the six months ended June 30, 2013.

Income Tax Benefit. We reported income tax benefit from continuing operations of $1 million and zero for the six months ended June 30, 2014 and June 30, 2013, respectively.

For the six months ended June 30, 2014 and 2013, the difference between the effective rate of one percent and zero percent, respectively, and the statutory rate of 35 percent resulted primarily from a valuation allowance against our net deferred tax assets. As of June 30, 2014 and 2013, we did not believe we would produce sufficient future taxable income, nor were there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

Income from Discontinued Operations. For the six months ended June 30, 2013, our income from discontinued operations was $5 million and primarily consisted of a $7 million DNE pension curtailment gain due to the termination of a majority of the Danskammer employees and closing of the Roseton sale, partially offset by a $2 million loss related to legacy capacity contracts executed with the Roseton facility which terminated upon the sale of the facility. There was no similar activity during the six months ended June 30, 2014. Please read Note 3—Acquisition and Divestitures for further discussion.

Net Income Attributable to Noncontrolling Interest. For the six months ended June 30, 2014, net income attributable to noncontrolling interest was $5 million related to the minority shareholder’s 20 percent interest in EEI.

Table of Contents

Adjusted EBITDA — Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2014:

	Six Months Ended June 30, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(164)
Income attributable to noncontrolling interest					5
Income tax benefit					(1)
Interest expense					72
Earnings from unconsolidated investments					(10)
Other items, net					45
Operating income (loss)	$4	$(33)	$32	$(56)	(53)
Depreciation expense	25	18	79	2	124
Amortization of intangible assets and liabilities, net	(3)	2	36	—	35
Earnings from unconsolidated investments	—	—	10	—	10
Other items, net	—	—	—	(45)	(45)
EBITDA	26	(13)	157	(99)	71
Acquisition and integration costs	—	8	—	—	8
Mark-to-market loss, net	19	38	18	—	75
Change in fair value of common stock warrants	—	—	—	49	49
Income attributable to noncontrolling interest	—	(5)	—	—	(5)
Gain on sale of assets, net	—	—	(14)	—	(14)
Other	5	2	1	(2)	6
Adjusted EBITDA	$50	$30	$162	$(52)	$190

Table of Contents

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2013:

	Six Months Ended June 30, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(287)
Income from discontinued operations, net of tax				(5)
Loss on extinguishment of debt				11
Interest expense				45
Other items, net				10
Operating loss	$(129)	$(44)	$(53)	(226)
Depreciation expense	23	79	1	103
Amortization of intangible assets and liabilities, net	64	63	—	127
Other items, net	—	—	(10)	(10)
EBITDA	(42)	98	(62)	(6)
Acquisition and integration costs	—	—	4	4
Mark-to-market loss, net	22	15	—	37
Change in fair value of common stock warrants	—	—	9	9
Other	—	1	6	7
Adjusted EBITDA	$(20)	$114	$(43)	$51

Adjusted EBITDA increased by $139 million from $51 million for the six months ended June 30, 2013 to $190 million for the six months ended June 30, 2014. The increase was primarily due to improved spark spreads in the Gas segment, improved realized energy prices for the Coal segment and the addition of the IPH segment. See Discussion of Segment Adjusted EBITDA for further information.

Table of Contents

Discussion of Segment Adjusted EBITDA — Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the six months ended June 30, 2014 and 2013, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$375	$230	$ 145	63 %
Capacity	3	1	2	200 %
Mark-to-market loss, net	(19)	(22)	3	14 %
Other (1)	(67)	(7)	(60)	(857)%
Total operating revenues	292	202	90	45 %
Operating Costs				
Cost of sales	(188)	(154)	(34)	(22)%
Contract amortization	3	(64)	67	105 %
Total operating costs	(185)	(218)	33	15 %
Gross margin	107	(16)	123	769 %
Operating and maintenance expense	(78)	(92)	14	15 %
Depreciation expense	(25)	(23)	(2)	(9)%
Gain on sale of assets, net	—	2	(2)	(100)%
Operating income (loss)	4	(129)	133	103 %
Depreciation expense	25	23	2	9 %
Amortization of intangible assets and liabilities, net	(3)	64	(67)	(105)%
EBITDA	26	(42)	68	162 %
Mark-to-market loss, net	19	22	(3)	(14)%
Other	5	—	5	100 %
Adjusted EBITDA	$50	$(20)	$ 70	350 %
Million Megawatt Hours Generated	9.9	9.4	0.5	5 %
In Market Availability for Coal-Fired Facilities (2)	90 %	90 %		
Average Capacity Factor for Coal-Fired Facilities (3)	76 %	72 %		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$58.29	$37.96	$ 20.33	54 %
Off-Peak: Indiana (Indy Hub)	$36.65	$27.92	$ 8.73	31 %

(1) For the six months ended June 30, 2014 and 2013, respectively, Other includes ($69) million and ($4) million in financial settlements, $2 million and $1 million in ancillary services and zero and ($4) million in other miscellaneous items.

(2) In Market Availability is an internal measurement calculation that reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.

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

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

Table of Contents

Operating income for the six months ended June 30, 2014 was $4 million compared to operating loss of $129 million for the six months ended June 30, 2013. Adjusted EBITDA totaled $50 million during the six months ended June 30, 2014 compared to a loss of $20 million during the same period in 2013. The $70 million increase in Adjusted EBITDA resulted from higher realized prices in the six months ended June 30, 2014 compared to the six months ended June 30, 2013. During the period LMP prices increased $132 million and the percentage of the fleet that was hedged declined further enhancing the impact of rising prices. The benefit associated with higher realized prices, together with a reduction in operating and maintenance expense of $17 million due to fewer planned outages more than offset increases in hedge losses of $65 million and higher delivered fuel costs of $23 million primarily due to the new rail transport agreement.

Table of Contents

IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the six months ended June 30, 2014:

(dollars in millions, except for price information)	Six Months Ended June 30, 2014	
Operating Revenues		
Energy	$ 403	
Capacity	18	
Mark-to-market loss, net	(38	)
Contract amortization	(21	)
Other (1)	21	
Total operating revenues	383	
Operating Costs		
Cost of sales	(308	)
Contract amortization	19	
Total operating costs	(289	)
Gross margin	94	
Operating and maintenance expense	(101	)
Depreciation expense	(18	)
Acquisition and integration costs	(8	)
Operating loss	(33	)
Depreciation expense	18	
Amortization of intangible assets and liabilities, net	2	
EBITDA	(13	)
Mark-to-market loss, net	38	
Acquisition and integration costs	8	
Income attributable to noncontrolling interest	(5	)
Other	2	
Adjusted EBITDA	$ 30	
Million Megawatt Hours Generated	12.1	
In Market Availability for IPH Facilities (2)	89	%
Average Capacity Factor for IPH Facilities (3)	66	%
Average Quoted Market Power Prices ($/MWh) (4):		
On-Peak: Indiana (Indy Hub)	$ 58.29	
Off-Peak: Indiana (Indy Hub)	$ 36.65	

---

(1) For the six months ended June 30, 2014, Other includes $27 million in financial settlements and ($5) million in ancillary services and ($1) million in other miscellaneous items.

(2) In Market Availability is an internal measurement calculation that reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.

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

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

Table of Contents

Operating loss for the six months ended June 30, 2014 was $33 million. Adjusted EBITDA totaled $30 million during the six months ended June 30, 2014. IPH generated 12.1 million MWh, a meaningful portion of which was hedged through the retail business and other third parties. During the six months ended June 30, 2014, the capacity factor was 66 percent due to planned and unplanned outages as well as unfavorable market conditions which adversely affected results.

Table of Contents

Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the six months ended June 30, 2014 and 2013, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2014 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$571	$301	$ 270	90 %
Capacity	113	108	5	5 %
Mark-to-market loss, net	(18)	(15)	(3)	(20)%
Contract amortization	(40)	(67)	27	40 %
Other (1)	(18)	90	(108)	(120)%
Total operating revenues	608	417	191	46 %
Operating Costs				
Cost of sales	(447)	(323)	(124)	(38)%
Contract amortization	4	4	—	— %
Total operating costs	(443)	(319)	(124)	(39)%
Gross margin	165	98	67	68 %
Operating and maintenance expense	(68)	(63)	(5)	(8)%
Depreciation expense	(79)	(79)	—	— %
Gain on sale of assets, net	14	—	14	100 %
Operating income (loss)	32	(44)	76	173 %
Depreciation expense	79	79	—	— %
Amortization of intangible assets and liabilities, net	36	63	(27)	(43)%
Earnings from unconsolidated investments	10	—	10	100 %
EBITDA	157	98	59	60 %
Mark-to-market loss, net	18	15	3	20 %
Gain on sale of assets, net	(14)	—	(14)	(100)%
Other	1	1	—	— %
Adjusted EBITDA	$162	$114	$ 48	42 %
Million Megawatt Hours Generated (2)	8.2	7.8	0.4	5 %
In Market Availability for Combined Cycle Facilities (3)	99 %	97 %		
Average Capacity Factor for Combined Cycle Facilities (4)	44 %	41 %		
Average Market On-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$13.71	$10.32	$ 3.39	33 %
PJM West	$32.71	$15.00	$ 17.71	118 %
North of Path 15 (NP 15)	$12.24	$12.76	$ (0.52)	(4)%
New York—Zone A	$43.69	$14.35	$ 29.34	204 %
Mass Hub	$22.99	$14.09	$ 8.90	63 %
Average Market Off-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$(14.45)	$0.24	$ (14.69)	(6,121)%
PJM West	$(2.40)	$2.06	$ (4.46)	(217)%
North of Path 15 (NP 15)	$2.38	$5.42	$ (3.04)	(56)%
New York—Zone A	$16.24	$5.93	$ 10.31	174 %

Mass Hub	$(7.65)	$(0.55)	$ (7.10)	(1,291)%
Average natural gas price—Henry Hub ($/MMBtu) (6)	$4.81	$3.75	$ 1.06	28 %

61

(1) For the six months ended June 30, 2014 and 2013, respectively, Other includes ($92) million and ($13) million in financial settlements, $46 million and $48 million in natural gas sales, $23 million and $15 million in ancillary services, $3 million and $32 million in tolls and $2 million and $8 million in RMR, option premiums and other miscellaneous items.
(2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility.
(3) In Market Availability is an internal measurement calculation that reflects the percentage of generation available when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues.
(4) Reflects actual production as a percentage of available capacity.
(5) Reflects the simple average of the on- and off-peak spark spreads available to a 7.0 MMBtu/MWh heat rate generator selling power at day-ahead prices and buying delivered natural gas at a daily cash market price and does not reflect spark spreads available to us.
(6) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Operating income for the six months ended June 30, 2014 was $32 million compared to operating loss of $44 million for the six months ended June 30, 2013. Adjusted EBITDA totaled $162 million during the six months ended June 30, 2014 compared to $114 million during the same period in 2013. The $48 million increase in Adjusted EBITDA primarily resulted from higher energy margin due to increased generation and higher spark spreads primarily at Independence, Ontelaunee and Casco Bay, capacity revenues primarily at Kendall and Ontelaunee, ancillary services across the Gas fleet and distributions from Black Mountain in the six months ended June 30, 2014 as compared to the same period in 2013. This increase was partially offset by a decrease in revenues generated on the Moss Landing toll and an increase in operating and maintenance expense.

Outlook

We expect that our future financial results will continue to be impacted by fuel and commodity prices, especially natural gas prices. Other factors to which our future financial results will remain sensitive include market structure and prices for electric energy, capacity and ancillary services, including pricing at our plant locations relative to pricing at their respective trading hubs, the volatility of fuel and electricity prices, transportation and transmission logistics, weather conditions and IMA. Further, there is a trend toward greater environmental regulation of all aspects of our business. As this trend continues, it is possible that we will experience additional costs associated with the handling and disposal of coal ash, how water used by our power generation facilities is withdrawn and treated before being discharged and more stringent air emission standards.

Coal. The Coal segment consists of four plants, all located in the MISO region, and totaling 2,980 MW.

As of August 1, 2014, our expected remaining generation volumes are 53 percent hedged volumetrically for 2014 and approximately 41 percent hedged volumetrically for 2015. As a result of the offsetting risks of our Coal and Gas segments, we are able to reduce the costs associated with hedging by executing a portion of the hedges with an internal affiliate. The internal hedges are cross-commodity hedges and we intend to expand this in the future. Beyond 2015, the portfolio is largely open, positioning Coal to benefit from possible future power market pricing improvements. We mitigate the risk of a breakdown between plant LMP prices and trading hub prices through participation in FTR markets and busbar swaps to the extent they are economically available. We plan to continue our hedging program over a one- to three-year period using various instruments, which includes the sale of natural gas swaps as a cross-commodity correlated hedge for our power revenue.

As of August 1, 2014, our expected coal requirements are fully contracted and priced in 2014. Our forecasted coal requirements for 2015 are 82 percent contracted and 60 percent priced. Our coal transportation requirements are fully contracted and priced for the next several years. We look to procure and price additional fuel opportunistically.

The MISO filed proposed Resource Adequacy Enhancements with FERC on July 20, 2011. The FERC conditionally approved MISO's proposal on June 11, 2012, leaving much of MISO's proposal in place. The new tariff provisions replace the monthly construct with a full planning year product (June 1 - May 31) and further recognize zonal deliverability capacity requirements. The first zonal auction was held in March 2013. For the 2013-2014 planning year, capacity cleared at $1.05 per MW-day for all zones. This low clearing price was likely caused by excess capacity conditions prevailing in MISO for the term of the planning year. We did not sell a material amount of our generation in the latest auction.

On April 14, 2014, MISO released the results of the 2014-2015 planning year capacity auction. Local Resource Zone 4, in which our assets are located, cleared at $16.75 per MW-day, compared to $1.05 per MW-day for the previous 2013-2014 planning year capacity auction. In the future, the potential retirement of marginal MISO coal capacity due to poor economics or expected environmental mandates and confirmed future capacity exports from MISO to PJM could also increase MISO capacity and energy pricing. As such, we expect to benefit from the 9.1 GW of MISO retirements by market participants that have been announced or retired to date. Year-to-date, our Coal segment has entered into total bilateral forward capacity sales in MISO in excess of 1,000 MW at prices up to $2.50 per kW-month.

Based on analysis of historical constraints near our generating facilities, we have identified opportunities to invest in transmission facilities upgrades which will help to mitigate the impact of congestion around our Baldwin plant. We are working with the transmission owner to potentially implement these upgrades. We continue to assess grid constraints impacting our other facilities to identify other opportunities to reduce congestion and improve LMPs at our Coal and IPH facilities.

IPH. The IPH segment consists of five plants, totaling 4,062 MW. The Coffeen, Edwards, Duck Creek and Newton facilities are located in the MISO region. Joppa is located within its own control area, known as EEI. Joppa sells all of its net power into three connected control areas: MISO, TVA and LGE.

As of August 1, 2014, our IPH expected generation volumes are 74 percent hedged volumetrically for 2014 and approximately 59 percent hedged volumetrically for 2015. The IPH hedging program will continue to use our retail business, Homefield Energy, to hedge a portion of the output from our IPH facilities. The retail hedges are well correlated to our facilities due to the close proximity of the hedge and through participation in FTR markets. We may use other instruments to hedge the power revenue. Homefield Energy's ability to keep and possibly grow its existing market share will impact IPH's hedge levels in the future.

As of August 1, 2014, our expected coal requirements for IPH are fully contracted and 93 percent priced for 2014. Our forecasted coal requirements for 2015 are 49 percent contracted and 28 percent priced. Our coal transportation requirements are fully contracted and priced for the next several years. We look to procure and price additional fuel opportunistically.

IPH realized capacity sales in the latest MISO 2014-2015 planning year capacity auction, clearing 1,995 MW. On May 23, 2014, PJM's RPM released its results for the 2017-2018 planning year, with a clearing price of $3.65 per kW-month, of which the IPH segment cleared 847 MW. We have also secured one segment of the transmission path required to transfer an additional 240 MW of capacity and energy to PJM which may be available for incremental capacity auction for the 2017-2018 planning year. In July 2014, we executed a long-term wholesale contract for up to 120 MW annually for 2018 through 2026 planning years for energy and capacity in Illinois bringing long-term, annual origination sales from the IPH segment to more than 470 MW.

Gas. The Gas segment consists of six plants, geographically diverse in four markets, totaling 6,078 MW. Approximately 62 percent of our power plant capacity in the CAISO market is contracted through 2014 under tolling agreements with LSEs and a RMR agreement.

The CAISO capacity market is a bilateral market in which LSEs are required to procure sufficient resources to meet their peak load plus a fifteen percent reserve margin. The CAISO faces challenges to ensure system reliability and the ability to integrate renewables into the system given the state's mandate to have 33 percent renewable resources by 2020. The CAISO and CPUC recently approved the Joint Reliability Plan in which the CAISO and CPUC will collaborate on several initiatives: (i) determination of multi-year resource adequacy procurement obligations for CPUC jurisdictional LSEs; (ii) development of a joint long-term planning assessment and (iii) development of a market-based reliability backstop mechanism to replace CPM (Capacity Procurement Mechanism), which is the administratively-priced mechanism currently used by CAISO. A flexible capacity requirement to support renewable integration has been imposed on CPUC jurisdictional LSEs and will be mandatory starting in 2015. The CAISO board recently approved the methodology and "must-offer" obligations for flexible capacity developed through a stakeholder process. We do not anticipate a significant near term change in capacity prices because energy efficiency programs and distributed generation of residential and commercial rooftop solar power have kept energy demand growth relatively flat. Additionally, CAISO studies on flexible capacity needs appear to show ample supplies through 2018.

The estimated useful lives of our generation facilities consider environmental regulations currently in place. With respect to Units 6 and 7 at our Moss Landing facility, we are continuing to review the potential impact of the California Water Intake Policy. We are currently depreciating these units through 2024; however, depending on (i) a final determination of the compliance term and requirements of the California Water Intake Policy and (ii) our ability to secure energy and/or capacity contracts in the future, we could decide to reduce operations or cease to operate the units prior to 2024. The Morro Bay facility was retired on February 5, 2014; we are currently evaluating alternatives for the site.

On October 10, 2013, Dynegy and SCE agreed to resolve prior contract termination disputes by entering into two new transactions. The pending arbitration and federal court litigation have been dismissed as a result of the new transactions. Under the first transaction, SCE agreed to purchase energy and capacity from our Moss Landing Energy Facility for 2014 and 2015. Under the second transaction, SCE agreed to purchase energy and capacity from the same facility for 2016. The 2016 transaction was conditioned on approval by the CPUC, which was received and became final in July 2014, 30 days after the CPUC resolution was issued.

In New England, eight forward capacity auctions have been held since the ISO-NE transitioned to a forward capacity market in June 2010. The highest clearing price of $15 per kW-month occurred in the most recent auction for the 2017-2018 market period. However, the "insufficient competition" clause in the ISO-NE tariff was triggered, resulting in existing generation receiving an administrative cap price of $7.025 per kW-month. Due to oversupply conditions, the seven prior annual auctions cleared at the designated floor. Changes made to the forward capacity market design removed the auction floor price and implemented a minimum offer price rule that sets a floor price for new entrants based on technology type. For the eighth auction, the floor price was removed. However, the auction cleared at the high mark, with existing generation receiving the administrative cap due to significant retirements in the region. ISO-NE is developing additional changes to the forward capacity market including performance incentives and a sloped demand curve which are expected to be in place for the ninth forward capacity auction in 2015.

In PJM, where the Kendall and Ontelaunee combined-cycle plants are located, eleven forward capacity auctions (known as RPM or Reliability Pricing Model) have been held since the transition from a daily capacity market in June 2007. RPM clearing prices have ranged from $0.50 per kW-month (Kendall, 2012-2013 planning year) and $1.24 per kW-month (Ontelaunee, 2007-2008 planning year) to $5.30 per kW-month (Kendall, 2010-2011 planning year) and $6.88 per kW-month (Ontelaunee, 2013-2014 planning year). The latest RPM auction was for the 2017-2018 planning year, which cleared at $3.65 per kW-month for both Kendall and Ontelaunee. The next RPM auction, for the 2018-2019 planning year will be conducted in May 2015.

Capacity pricing for the NYISO seems to be recovering from the low point in 2011. The most recent summer and winter auctions have cleared higher than the previous auctions with summer 2014 at $5.15 per kW-month and winter 2013-2014 at $2.58 per kW-month for the rest of state market. We attribute the rebound in part to the FERC Order on buyer-side mitigation, affecting in-City resources, and retirements. For 2014, approximately 91 percent of the capacity for our Independence facility has been contracted, of which, approximately 75 percent has been contracted at a favorable premium compared to current market prices through October 31, 2014.

On May 23, 2014, the D.C. Circuit Court of Appeals vacated FERC Order No. 745. If the May 23 decision stands, it will likely affect how Demand Response can participate in the energy, ancillary service and capacity markets. FERC requested an en banc review of this decision on July 7, 2014. It is too early to evaluate market impacts at this time.

Excluding volumes subject to tolling agreements, as of August 1, 2014, our Gas portfolio is 51 percent hedged volumetrically through 2014 and approximately 36 percent hedged volumetrically for 2015. As a result of the offsetting risks of our Gas and Coal segments, we are able to reduce the costs associated with hedging by executing a portion of our natural gas hedges with an internal affiliate. We continue to manage our remaining commodity price exposure to changing fuel and power prices in accordance with our risk management policy.

Environmental and Regulatory Matters

Please read Item 1. Business-Environmental Matters in our Form 10-K and Item 2. Results of Operations-Outlook-Environmental and Regulatory Matters in our Form 10-Q for the period ended March 31, 2014 for a detailed discussion of our environmental and regulatory matters.

The Clean Air Act

Mercury/HAPs. In July 2014, various parties filed petitions for certiorari with the U.S. Supreme Court seeking review of the U.S. Court of Appeals for the District of Columbia Circuit's decision upholding the MATS rule for EGUs. Given the air emission controls already employed, we expect that each of our Coal and IPH segment facilities except Edwards Unit 1 will be in compliance with the MATS rule emission limits without the need for significant additional investment. We continue to evaluate the ability of Edwards Unit 1 to meet the MATS limits until such time as MISO allows us to retire the unit. We also continue to monitor the performance of our other units and evaluate approaches to optimizing compliance strategies.

Cross-State Air Pollution Rule. On April 29, 2014, the U.S. Supreme Court issued a decision in EPA v. EME Homer City Generation, L.P. upholding the CSAPR. The Court remanded the case to the Court of Appeals for the District of Columbia Circuit for further proceedings consistent with its decision. On June 26, 2014, the EPA filed a motion in the court of appeals asking the court to lift the stay of the CSAPR such that Phase I of the CSAPR would begin on January 1, 2015. Pending further action by the court of appeals, the CAIR remains in effect. If the CSAPR were to be reinstated in 2015, we would not expect to incur

Table of Contents

any material capital compliance costs given the SO_2 and NO_x emission controls currently installed and operating on our affected facilities.

IPH Variance. In January 2014, an environmental group filed a petition for review in the Illinois Fourth District Appellate Court of the IPCB's November 2013 decision and order granting IPH a variance to extend the applicable compliance dates for MPS SO_2 emission limits through December 31, 2019, subject to certain conditions. On January 17, 2014, we filed a Motion to Dismiss. On February 24, 2014, the Appellate Court granted our motion and dismissed the appeal. On April 1, 2014, the environmental group filed a petition for leave to appeal the Appellate Court's decision with the Illinois Supreme Court. On May 5, 2014, we filed an answer opposing review by the Illinois Supreme Court. We believe the variance was properly granted and that the Appellate Court's judgment dismissing the petition for review was proper. We will vigorously defend our position.

Edwards Clean Air Litigation. In April 2013, environmental groups filed a citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our IPH segment's Edwards facility. The District Court has scheduled the trial date for February 2016. We dispute the allegations and will defend the case vigorously.

Wood River CAA Section 114 Information Request. In May 2014, we received an information request from the EPA concerning our Coal segment's Wood River Station's compliance with the Illinois State Implementation Plan and associated permits. We responded to the EPA's request and are currently unable to predict the EPA's response, if any.

The Clean Water Act

Cooling Water Intake Structures. On May 16, 2014, the EPA issued its final rule for cooling water intake structures at existing facilities. The final rule establishes seven alternatives for complying with the best technology available requirement for reducing impingement mortality, including modified traveling screens, closed-cycle cooling, a numeric impingement standard, or a site-specific determination. For entrainment, the permitting authority is required to establish a case-by-case standard considering several factors, including social costs and benefits. The rule does not require closed-cycle cooling and provides that closed-cycle cooling includes impoundments in waters of the United States that were created for the purpose of serving as part of a cooling water system. The rule also includes provisions to address endangered and threatened species. Compliance with the final rule's entrainment and impingement mortality standards is required as soon as practicable, but will vary by site depending on several different factors, including determinations made by the state permitting authority and the timing of renewal of a facility's NPDES permit. In general, compliance is expected to be required over the period 2018 to 2022.

Our ultimate compliance approach with the final rule at any particular facility will depend on numerous factors, including implementation by the relevant state permitting authority, the results of technology, biological and other required studies, and the applicable compliance deadline. At this time, based on our initial review of the EPA's final rule, we estimate the cost of our compliance will require an average of approximately $8 million annually over a five-year compliance period. This estimate assumes the Baldwin and Duck Creek facilities' cooling water impoundments are closed-cycle cooling systems and cooling towers are not required at any facility. This estimate could change significantly depending upon a variety of factors, including site-specific determinations made by states in implementing the final rule.

Havana NPDES Permit. In September 2012, the Illinois EPA issued a renewal NPDES permit for the Coal segment's Havana Power Station. In October 2012, environmental interest groups filed a petition for review with the IPCB challenging the permit. The petitioners allege that the permit does not adequately address the discharge of wastewaters associated with newly installed air pollution control equipment (i.e., a spray dryer absorber and activated carbon injection system to reduce SO_2 and mercury air emissions) at Havana. In 2013, the IPCB had dismissed petitioners' separate petition seeking to reopen and modify the NPDES permit to include mercury discharge limits. On June 5, 2014, the IPCB granted and denied in part cross motions for summary judgment and remanded the permit to the Illinois EPA to require monthly monitoring for mercury. In July 2014, the environmental interest groups filed a petition for review of the IPCB's decision in the Illinois Fourth District Appellate Court.

Coal Combustion Residuals

The EPA is expected to issue a final CCR rule in late 2014 and intends to align its steam electric effluent limitation guidelines rule with the CCR rule. We are currently evaluating these proposed regulations to determine whether current management of CCR, including beneficial reuse, and the use of the CCR surface impoundments should be altered. We are also evaluating the potential costs to comply with these proposed regulations, which could be material, if such regulations are adopted. At this time, based on the requirements set forth in the EPA's April 2010 Subtitle D CCR proposed rule and the EPA's 2013 proposed effluent limitations guideline rule, we estimate the cost of our compliance with the CCR and effluent limitations guidelines rules would require an average of approximately $25 million annually over a five-year compliance period. This estimate assumes the EPA classifies CCR as "non-hazardous" and the final effluent limitations guideline rule is within the EPA's four stated preferred options. This estimate also does not include the cost of compliance associated with closure of existing surface impoundments, which are

Table of Contents

addressed in our AROs. This estimate could change significantly depending upon a variety of factors, including the requirements of the final EPA rules as promulgated.

Climate Change

Federal Regulation of Greenhouse Gases. On June 2, 2014, the EPA issued a proposed rule to reduce CO_2 emissions from existing fossil-fuel EGUs. The proposal, known as the Clean Power Plan, would not directly establish emission rates for fossil-fuel EGUs, but instead would require states to meet state-specific CO_2 emissions rate targets (expressed as weighted-average pounds of CO_2 per net MWh), beginning with an interim rate in 2020 and a final rate to be achieved by 2030. Overall, the EPA expects the proposal would reduce CO_2 emissions from the power generation sector by 30 percent nationwide from 2005 levels.

Under the proposed rule, each state would be required to reduce CO_2 emissions rates from fossil-fuel EGUs to varying degrees. The emission rate targets are based on each state's unique mix of historical fossil-fuel EGU CO_2 emissions and projected emissions, reflecting individual state regulatory programs such as renewable energy mandates and energy efficiency standards. The EPA intends for states to take the lead in determining how to reduce CO_2 emissions. The proposed state-specific emissions targets are based on four approaches to CO_2 reduction, namely, heat rate improvements at existing solid-fuel EGUs, greater use of natural gas in place of the most carbon intensive affected EGUs, greater use of low- or zero-carbon generation units, and demand side energy efficiency measures that reduce the amount of generation. States would choose how to meet their specific emissions targets and could do so by either meeting the specified target emissions rate or establishing an equivalent mass-based cap-and-trade program. States also would have the flexibility to comply using their own programs or by joining a multi-state approach to compliance. States generally would be required to submit implementation plans detailing their CO_2 reduction plans by June 2016.

On June 2, 2014, the EPA also issued proposed CO_2 emission standards for modified and reconstructed power plants. For modified utility boilers and IGCC units, the EPA proposed two alternatives standards. Under the first alternative, modified sources would be required to meet a limit determined by the unit's best historical annual CO_2 emission rate since 2002, plus an additional two percent reduction. However, the limit would be no lower than 1,900 lbs CO_2/MWh for sources with heat input greater than 2,000 MMBtu/hr or 2,100 lbs CO_2/MWh for sources with heat input less than or equal to 2,000 MMBtu/hr. Under the second alternative, the applicable emissions limit would depend on when the modification occurs. If the source is modified before it becomes subject to a Clean Power Plan, the first alternative identified above would apply. If the source is modified after it becomes subject to a Clean Power Plan, the source must meet a unit-specific limit determined by the implementing authority based on the results of an energy efficiency improvement audit. The proposed CO_2 emission standard for reconstructed utility boilers and IGCC units is 1,900 lbs CO_2/MWh for sources with heat input greater than 2,000 MMBtu/hr or 2,100 lbs CO_2/MWh for sources with a lower heat input. The proposed standard for modified or reconstructed natural gas fired stationary combustion turbines is identical to the proposed NSPS for such units (e.g., 1,000 lbs CO_2/MWh-gross).

The EPA anticipates issuing final rules for the Clean Power Plan and modified/reconstructed power plants in June 2015. We continue to analyze the proposed rules, the potential impacts on our power generation facilities, and how the proposals intersect with electricity market design. The nature and scope of CO_2 emission reduction requirements that ultimately may be imposed on our facilities as result of the EPA's EGU CO_2 reduction rulemakings are uncertain at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

Climate Change Litigation. On June 23, 2014, the U.S. Supreme Court issued a decision in the litigation involving several EPA rules concerning the regulation of GHG emissions under the CAA's PSD and Title V permitting programs. The Court held that the EPA may not impose PSD or Title V permitting requirements on facilities based solely on emissions of GHGs. In doing so, the Court also invalidated the EPA's Tailoring Rule, which had modified the emissions permitting thresholds for PSD and Title V as established in the CAA to account for GHGs, holding that the EPA could not change the statutory applicability terms of the CAA. However, the Court also concluded that the EPA may impose BACT requirements on GHG emissions if a facility is otherwise subject to BACT for emissions of other pollutants. The Court also determined that the EPA may establish a de minimis threshold below which BACT would not be required for GHG emissions, but left it open to the EPA to justify the appropriate threshold.

State Regulation of Greenhouse Gases. In May 2014, the CARB held its seventh GHG allowance auction, with 2014 auction allowances selling at a clearing price of $11.50 per ton and 2017 auction allowances selling at a clearing price of $11.34. The CARB's next quarterly auction is scheduled for August 18, 2014. We have participated in each of the quarterly CARB auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets.

We estimate the cost of GHG allowances required to operate our units in California during 2014 will be approximately $23 million; however, we expect that the cost of compliance would be reflected in the power market, and the actual impact to gross margin would be largely offset by an increase in revenue. Due to the tolling agreement for Moss Landing Units 6 and 7 under

Table of Contents

which GHG allowance costs are passed through to the tolling counterparty and our retirement of the Morro Bay facility, we expect to only acquire allowances covering the GHG emissions of Moss Landing Units 1 and 2.

In June 2014, RGGI held its twenty-fourth auction, in which approximately 18 million allowances for the second control period were sold at a clearing price of $5.02 per allowance. RGGI's next quarterly auction is scheduled for September 2014. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets.

We estimate the cost of RGGI allowances required to operate our affected facilities in New York and Maine during 2014 will be approximately $14 million. While the updated RGGI rules are expected to increase the cost of allowances required to operate our affected facilities in future years, we expect that the cost of compliance would be reflected in the power market and the actual impact to gross margin would be largely offset by an increase in revenue.

RISK MANAGEMENT DISCLOSURES

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

(amounts in millions)	As of and for the Six Months Ended June 30, 2014
Fair value of portfolio at December 31, 2013	$(62)
Risk management losses recognized through the statement of operations in the period, net	(83)
Contracts realized or otherwise settled during the period	12
Changes in collateral/margin netting	4
Fair value of portfolio at June 30, 2014	$(129)

The net risk management liability of $129 million is the aggregate of the following line items on our unaudited consolidated balance sheets: Current Assets—Assets from risk management activities, Other Assets—Assets from risk management activities, Current Liabilities—Liabilities from risk management activities and Other Liabilities—Liabilities from risk management activities.

Risk Management Asset and Liability Disclosures. The following table provides an assessment of net contract values by year as of June 30, 2014, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total	2014	2015	2016	2017	2018	Thereafter
Market quotations (1) (2)	$(122)	$(62)	$(37)	$(15)	$(6)	$(2)	$—
Prices based on models (2)	(15)	(21)	4	2	—	—	—
Total (3)	$(137)	$(83)	$(33)	$(13)	$(6)	$(2)	$—

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

(2) The market quotations category represents our transactions classified as Level 1 and Level 2. The prices based on models category represents transactions classified as Level 3. Please read Note 4—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

(3) Excludes $8 million of broker margin that has been netted against Risk Management liabilities on our unaudited consolidated balance sheets. Please read Note 4—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

This Form 10-Q includes statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward-looking statements." All statements included or incorporated by reference in this quarterly report, other than statements of historical fact, that address activities, events or developments that we 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 and use words such as “anticipate,”

67

Table of Contents

“estimate,” “project,” “forecast,” “plan,” “may,” “will,” “should,” “expect” and other words of similar meaning. In particular, include, but are not limited to, statements relating to the following:

- 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 timing of a recovery in natural gas prices, if any;
- 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 and retail power generation market, including the anticipation of plant retirements and higher market pricing over the longer term;
- the effects of, or changes to, MISO or PJM power procurement process;
- the effectiveness of our strategies to capture opportunities presented by changes in commodity prices and to manage our exposure to energy price volatility;
- efforts to secure retail sales and the ability to grow the retail business;
- efforts to identify opportunities to reduce congestion and improve busbar power prices;
- beliefs and assumptions about weather and general economic conditions;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- expectations regarding our compliance with the Credit Agreement, including collateral demands, interest expense, any applicable financial ratios and other payments;
- 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 costs and scope of the ongoing demolition and site remediation efforts at the South Bay and Vermilion facilities;
- beliefs regarding redevelopment efforts for the Morro Bay facility;
- ability to mitigate impacts associated with expiring RMR and/or capacity contracts;
- beliefs about the outcome of legal, administrative, legislative and regulatory matters;
- the timing and anticipated benefits to be achieved through our company-wide savings improvement programs, including our PRIDE initiative; and
- expectations regarding performance standards and capital and maintenance expenditures.

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

CRITICAL ACCOUNTING POLICIES

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

Item 3—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our Form 10-K for a discussion of our exposure to commodity price variability and other market risks related to our net non-trading derivative assets and liabilities, including foreign currency exchange rate risk. The following is a discussion of the more material of these risks and our relative exposures as of June 30, 2014.

Table of Contents

Value at Risk (“VaR”). The following table sets forth the aggregate daily VaR of the mark-to-market portion of our risk management portfolio primarily associated with the Coal and Gas segments. The VaR calculation does not include market risks associated with the accrual portion of the risk management portfolio that is designated as “normal purchase, normal sale,” nor does it include expected future production from our generating assets. Please read “VaR” in our Form 10-K for a complete description of our valuation methodology. The daily VaR at June 30, 2014 compared to December 31, 2013 remained constant period over period. The average VaR at June 30, 2014 compared to December 31, 2013 increased due to a change in position.

Daily and Average VaR for Risk Management Portfolios

(amounts in millions)	June 30, 2014	December 31, 2013
One day VaR—95 percent confidence level	$7	$7
One day VaR—99 percent confidence level	$9	$10
Average VaR—95 percent confidence level for the rolling twelve months ended	$6	$4

Credit Risk. The following table represents our credit exposure at June 30, 2014 associated with the mark-to-market portion of our risk management portfolio, on a net basis.

Credit Exposure Summary

(amounts in millions)	Investment Grade Quality	Non-Investment Grade Quality	Total
Type of Business:			
Financial institutions	$2	$—	$2
Oil and gas producers	1	—	1
Utility and power generators	7	—	7
Total	$10	$—	$10

Interest Rate Risk

We are exposed to fluctuating interest rates related to our variable rate financial obligations, which consist of amounts outstanding under our Credit Agreement. We currently use interest rate swaps to mitigate this interest rate exposure. Our interest rate hedging instruments are recorded at their fair value. As a result of our outstanding interest rate derivatives, we do not have any significant exposure to changes in LIBOR.

The absolute notional amounts associated with our interest rate contracts were as follows at June 30, 2014 and December 31, 2013, respectively:

	June 30, 2014	December 31, 2013
Interest rate swaps (in millions of U.S. dollars) (1)	$789	$796
Fixed interest rate paid (percent)	3.15	3.15

---

(1) The calculation period for $248 million of the interest rate swaps began June 30, 2013, and the calculation period for the remaining $541 million began October 31, 2013.

Item 4—CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of our management, including our CEO and our CFO, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of June 30, 2014.

Changes in Internal Controls Over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the quarter ended June 30, 2014.

PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS

Please read Note 10—Commitments and Contingencies—Legal Proceedings to the accompanying unaudited consolidated financial statements for a discussion of the legal proceedings that we believe could be material to us.

Item 1A—RISK FACTORS

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

Item 6—EXHIBITS

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

Exhibit Number	Description
**10.1	Waiver and Amendment No. 1 to Letter of Credit and Reimbursement Agreement by and between Illinois Power Marketing Company and Union Bank, N.A.
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

---

** Filed herewith.

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

DYNEGY INC.

SIGNATURE

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

			DYNEGY INC.
Date:	August 7, 2014	By:	/s/ CLINT C. FREELAND Clint C. Freeland Executive Vice President and Chief Financial Officer