DYNEGY INC.
Form 10-Q
August 07, 2015
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, 2015

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, 128,177,031 shares outstanding as of July 21, 2015.

Table of Contents

TABLE OF CONTENTS

Table of Contents

DEFINITIONS

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

CAISO	The California Independent System Operator
CAA	Clean Air Act
CPUC	California Public Utility Commission
CT	Combustion Turbine
CWA	Clean Water Act
EGU	Electric Generating Units
EPA	Environmental Protection Agency
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
HAPs	Hazardous Air Pollutants, as defined by the Clean Air Act
IMA	In-market Asset Availability
IPCB	Illinois Pollution Control Board
IPH	IPH, LLC (formerly known as Illinois Power Holdings, LLC)
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Pricing
MAAC	Mid-Atlantic Area Council
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	One Million British Thermal Units
Moody’s	Moody’s Investors Service Inc.
MW	Megawatts
MWh	Megawatt Hour
NM	Not Meaningful
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PRIDE	Producing Results through Innovation by Dynegy Employees
RFO	Request for Offers
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	U.S. Securities and Exchange Commission
SEMA/RI	Southeastern Massachusetts and Rhode Island
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, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$711	$1,870
Restricted cash	—	113
Accounts receivable, net of allowance for doubtful accounts of $2 and $2, respectively	439	270
Inventory	523	208
Assets from risk management activities	78	78
Intangible assets	124	27
Prepayments and other current assets	222	108
Total Current Assets	2,097	2,674
Property, Plant and Equipment	9,309	3,685
Accumulated depreciation	(643)	(430)
Property, Plant and Equipment, Net	8,666	3,255
Other Assets		
Investment in unconsolidated affiliate	199	—
Restricted cash	—	5,100
Assets from risk management activities	22	2
Goodwill	837	—
Intangible assets	104	38
Deferred income taxes	22	20
Other long-term assets	202	143
Total Assets	$12,149	$11,232

See the notes to consolidated financial statements.

Table of Contents

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

	June 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$351	$216
Accrued interest	74	80
Deferred income taxes	58	20
Intangible liabilities	113	45
Accrued liabilities and other current liabilities	179	157
Liabilities from risk management activities	119	132
Debt, current portion	52	31
Total Current Liabilities	946	681
Debt, long-term portion	7,079	7,075
Other Liabilities		
Liabilities from risk management activities	137	31
Asset retirement obligations	324	205
Intangible liabilities	93	36
Other long-term liabilities	251	181
Total Liabilities	8,830	8,209
Commitments and Contingencies (Note 14)		
Stockholders’ Equity		
Preferred stock, $0.01 par value, 20,000,000 shares authorized at June 30, 2015 and December 31, 2014:		
Series A 5.375% mandatory convertible preferred stock, $0.01 par value; 4,000,000 shares issued and outstanding at June 30, 2015 and December 31, 2014	400	400
Common stock, $0.01 par value, 420,000,000 shares authorized at June 30, 2015 and December 31, 2014; 128,177,031 shares and 124,436,941 shares issued and outstanding at June 30, 2015 and December 31, 2014, respectively	1	1
Additional paid-in capital	3,435	3,338
Accumulated other comprehensive income, net of tax	14	20
Accumulated deficit	(528)	(736)
Total Dynegy Stockholders’ Equity	3,322	3,023
Noncontrolling interest	(3)	—
Total Equity	3,319	3,023
Total Liabilities and Equity	$12,149	$11,232

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,	
	2015	2014	2015	2014
Revenues	$990	$521	$1,622	$1,283
Cost of sales, excluding depreciation expense	(496)	(365)	(873)	(917)
Gross margin	494	156	749	366
Operating and maintenance expense	(250)	(136)	(361)	(246)
Depreciation expense	(175)	(57)	(239)	(124)
Gain (loss) on sale of assets, net	(1)	14	(1)	14
General and administrative expense	(35)	(29)	(65)	(55)
Acquisition and integration costs	(23)	(2)	(113)	(8)
Operating income (loss)	10	(54)	(30)	(53)
Earnings from unconsolidated investments	3	10	3	10
Interest expense	(132)	(42)	(268)	(72)
Other income and expense, net	4	(39)	(1)	(45)
Loss before income taxes	(115)	(125)	(296)	(160)
Income tax benefit (Note 15)	501	3	501	1
Net income (loss)	386	(122)	205	(159)
Less: Net income (loss) attributable to noncontrolling interest	(2)	1	(3)	5
Net income (loss) attributable to Dynegy Inc.	388	(123)	208	(164)
Less: Dividends on preferred stock	6	—	11	—
Net income (loss) attributable to Dynegy Inc. common stockholders	$382	$(123)	$197	$(164)
Earnings (Loss) Per Share (Note 17):				
Basic earnings (loss) per share attributable to Dynegy Inc. common stockholders	$2.98	$(1.23)	$1.56	$(1.64)
Diluted earnings (loss) per share attributable to Dynegy Inc. common stockholders	$2.73	$(1.23)	$1.49	$(1.64)
Basic shares outstanding	128	100	126	100
Diluted shares outstanding	142	100	140	100

See the notes to consolidated financial statements.

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income (loss)	$386	$(122)	$205	$(159)
Other comprehensive loss before reclassifications:				
Actuarial loss (net of tax of zero, zero, zero and zero, respectively)	(5)	—	(5)	(3)
Amounts reclassified from accumulated other comprehensive income:				
Amortization of unrecognized prior service credit and actuarial gain (net of tax of zero, zero, zero and zero, respectively)	(1)	(1)	(2)	(2)
Other comprehensive loss, net of tax	(6)	(1)	(7)	(5)
Comprehensive income (loss)	380	(123)	198	(164)
Less: Comprehensive income (loss) attributable to noncontrolling interest	(2)	1	(3)	4
Total comprehensive income (loss) attributable to Dynegy Inc.	$382	$(124)	$201	$(168)

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, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$205	$(159)
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Depreciation expense	239	124
Non-cash interest expense	15	10
Amortization of intangibles	(9)	35
Risk management activities	(66)	71
(Gain) loss on sale of assets, net	1	(14)
Earnings from unconsolidated investments	(3)	—
Deferred income taxes	(501)	(1)
Change in value of common stock warrants	2	49
Other	23	19
Changes in working capital:		
Accounts receivable, net	(17)	63
Inventory	(42)	(18)
Prepayments and other current assets	49	14
Accounts payable and accrued liabilities	76	(28)
Changes in non-current assets	(12)	(6)
Changes in non-current liabilities	19	4
Net cash provided by (used in) operating activities	(21)	163
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(102)	(69)
Proceeds from asset sales, net	—	14
Acquisitions, net of cash acquired	(6,092)	—
Decrease in restricted cash	5,148	—
Other investing	(10)	—
Net cash used in investing activities	(1,056)	(55)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	6	12
Repayments of borrowings	(27)	(4)
Financing costs from debt issuance	(31)	(1)
Financing costs from equity issuance	(6)	—
Dividends paid	(12)	—
Interest rate swap settlement payments	(8)	(9)
Other financing	(4)	(1)
Net cash used in financing activities	(82)	(3)
Net increase (decrease) in cash and cash equivalents	(1,159)	105
Cash and cash equivalents, beginning of period	1,870	843
Cash and cash equivalents, end of period	$711	$948

Other non-cash investing activity:		
Non-cash capital expenditures	$(32)	$(3)
Non-cash consideration transferred for Acquisitions	$(105)	$—

See the notes to consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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 the Generally Accepted Accounting Principles of the United States of America ("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. 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, 2014, filed with the SEC on February 25, 2015, 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 its direct and indirect subsidiaries.

Our current business operations are focused primarily on the unregulated 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). All significant intercompany transactions have been eliminated. Please read Note 19—Segment Information for further discussion.

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 ("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

Use of Estimates. The preparation of unaudited 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.

The accounting policies followed by the Company are set forth in Note 2—Summary of Significant Accounting Policies in our Form 10-K. The accompanying unaudited consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries. Accounting policies for all of our operations are in accordance with accounting principles generally accepted in the United States of America. There have been no significant changes to our accounting policies during the six months ended June 30, 2015. Due to our recent Acquisitions in April 2015, we have added the following significant policies:

Undivided Interest Accounting. We account for our undivided interests in certain of our coal-fired power generation facilities whereby our proportionate share of each facility's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying unaudited consolidated financial statements.

Goodwill. Goodwill represents, at the time of an acquisition, the excess of purchase price over fair value of net assets acquired. The carrying amount of our goodwill will be periodically reviewed, at least annually, for impairment and whenever events or changes in circumstances indicate that the carrying value may not be recoverable. In accordance with Accounting Standards Codification ("ASC") 350, Intangibles-Goodwill and Other, we can opt to perform a qualitative assessment to test goodwill for impairment or we can directly perform a two-step impairment test. Based on our qualitative assessment, if we determine that the fair value of a reporting unit is more likely than not (i.e., a likelihood of more than 50 percent) to be less than its carrying amount, the two-step impairment test will be performed.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

In the absence of sufficient qualitative factors, goodwill impairment is determined using a two-step process:

- Step one—Identify potential impairment by comparing the fair value of a reporting unit to the book value, including goodwill. If the fair value exceeds book value, the goodwill of the reporting unit is not considered impaired. If the book value exceeds fair value, proceed to step two.
- Step two—Compare the implied fair value of the reporting unit's goodwill to the book value of the reporting unit's goodwill. If the book value of goodwill exceeds the implied fair value, an impairment charge is recognized for the excess.

Accounting Standards Adopted During the Current Period

Reporting Discontinued Operations and Asset Disposals. In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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. The adoption of this ASU did not have a material impact on our unaudited consolidated financial statements or disclosures.

Accounting Standards Not Yet Adopted

Inventory. In July 2015, the FASB issued ASU 2015-011-Inventory (Topic 330). The amendments in this ASU require that inventory is measured at the lower of cost and net realizable value ("NRV"), with the latter defined as the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. This ASU eliminates the need to determine market or replacement cost and evaluate whether it is above the ceiling at NRV or below the floor (NRV less a normal profit margin). The guidance in this ASU is effective prospectively for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We do not anticipate the adoption of this ASU will have a material impact on our unaudited consolidated financial statements.

Debt Issuance Costs. In April 2015, the FASB issued ASU 2015-03-Interest-Imputation of Interest (Subtopic 835-30). The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update. The guidance in this ASU is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted. The adoption of this ASU should be applied on a retrospective basis, affecting all balance sheet periods presented. We do not anticipate the adoption of this ASU will have a material impact on our unaudited consolidated balance sheets.

Consolidation. In February 2015, the FASB issued ASU 2015-02-Consolidation (Topic 810). The amendments in this ASU respond to concerns about the current accounting for consolidation of certain legal entities, in particular: (i) consolidation of limited partnerships and similar legal entities, (ii) evaluating fees paid to a decision maker or a service provider as a variable interest, (iii) the effect of fee arrangements on the primary beneficiary determination, (iv) the effect of related parties on the primary beneficiary determination and (v) consolidation of certain investment funds. The guidance in this ASU is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted in an interim period. We do not anticipate the adoption of this ASU will have a material impact on our unaudited consolidated financial statements.

Extraordinary and Unusual Items. In January 2015, the FASB issued ASU 2015-01-Income Statement-Extraordinary and Unusual Items (Subtopic 225-20). The amendments in this ASU eliminate from GAAP the concept of extraordinary items and will no longer require separate classification of these items within the statement of operations. Presentation and disclosure guidance for items that are unusual in nature or occur infrequently will be retained and will be expanded to include items that are both unusual in nature and infrequently occurring. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Reporting entities may elect to apply the amendments prospectively only, or retrospectively for all prior periods presented in the financial statements. Early adoption is permitted provided that the guidance is applied from the beginning of the fiscal year of adoption. We do not anticipate the adoption of this ASU will have a material impact on our unaudited consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Revenue from Contracts with Customers. In May 2014, the FASB and International Accounting Standards Board ("IASB") jointly issued ASU 2014-09-Revenue from Contracts with Customers (Topic 606). The amendments in this ASU develop a common revenue standard for GAAP and International Financial Reporting Standards ("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, 2017, with early adoption permitted for interim and annual periods beginning after December 15, 2016. We are currently assessing this ASU; however, we do not anticipate the adoption of this ASU will have a material impact on our unaudited consolidated financial statements.

Note 3—Acquisitions

Acquisitions

ECP Purchase Agreements. On April 1, 2015 (the "EquiPower Closing Date"), pursuant to the terms of the stock purchase agreement dated August 21, 2014, as amended (the "ERC Purchase Agreement"), our wholly-owned subsidiary, Dynegy Resource II, LLC (the "ERC Purchaser") purchased 100 percent of the equity interests in EquiPower Resources Corp. ("ERC") from certain affiliates of Energy Capital Partners (collectively, the "ERC Sellers") thereby acquiring (i) five combined cycle natural gas-fired facilities in Connecticut, Massachusetts and Pennsylvania, (ii) a partial interest in one natural gas-fired peaking facility in Illinois, (iii) two gas and oil-fired peaking facilities in Ohio and (iv) one coal-fired facility in Illinois (the "ERC Acquisition").

On the EquiPower Closing Date, in a related transaction, pursuant to a stock purchase agreement and plan of merger dated August 21, 2014, as amended (the "Brayton Purchase Agreement" and together with the ERC Purchase Agreement, the "ECP Purchase Agreements"), our wholly-owned subsidiary Dynegy Resource III, LLC (the "Brayton Purchaser" and together with the ERC Purchaser, the "ECP Purchasers") purchased 100 percent of the equity interests in Brayton Point Holdings, LLC ("Brayton") from certain affiliates of Energy Capital Partners (collectively, the "Brayton Sellers" and together with the ERC Sellers, the "ECP Sellers"), thereby acquiring a coal-fired facility in Massachusetts (the "Brayton Acquisition").

The ERC Acquisition and the Brayton Acquisition (collectively, the "EquiPower Acquisition") added approximately 6,300 MW of generation in Connecticut, Illinois, Massachusetts, Ohio and Pennsylvania for an aggregate base purchase price of approximately $3.35 billion in cash plus approximately $105 million in common stock of Dynegy, subject to certain adjustments. In aggregate, the resulting operations from the two coal-fired facilities acquired from the ECP Sellers are reported within our Coal segment, while related operations from the six natural gas-fired and two gas and oil-fired facilities are reported within our Gas segment.

Under the ECP Purchase Agreements, the ECP Purchasers and ECP Sellers have agreed to indemnify the other applicable parties for breaches of representations and warranties, breaches of covenants and certain other matters, subject to certain exceptions and limitations. Neither the ECP Purchasers nor the ECP Sellers, in the aggregate, are entitled to indemnification in excess of $276 million, and $104 million of the purchase price will be held in escrow for one year after closing to support the post-closing adjustment and the indemnification obligations of the ECP Sellers.

Duke Midwest Purchase Agreement. On April 2, 2015 (the "Duke Midwest Closing Date"), pursuant to the terms of the purchase and sale agreement dated August 21, 2014, as amended (the "Duke Midwest Purchase Agreement"), our wholly-owned subsidiary Dynegy Resource I, LLC ("DRI") purchased 100 percent of the membership interests in Duke Energy Commercial Asset Management, LLC and Duke Energy Retail Sales, LLC, from two affiliates of Duke Energy Corporation (collectively, "Duke Energy"), thereby acquiring approximately 6,200 MW of generation in (i) three combined cycle natural gas-fired facilities located in Ohio and Pennsylvania, (ii) two natural gas-fired peaking facilities located in Ohio and Illinois, (iii) one oil-fired peaking facility located in Ohio, (iv) partial interests in five coal-fired facilities located in Ohio and (v) a retail energy business for a base purchase price of approximately $2.80 billion in cash (the "Duke Midwest Acquisition"), subject to certain adjustments. We operate two of the five coal-fired facilities, the Miami Fort and Zimmer facilities, with other owners operating the three remaining facilities. The operations from the retail energy business, the five coal-fired and the one oil-fired facilities acquired from Duke Energy are reported within our Coal segment, while related operations from the five natural gas-fired facilities are reported within our Gas segment.

Under the Duke Midwest Purchase Agreement, DRI and Duke Energy have agreed to indemnify the other applicable parties for breaches of representations and warranties, breaches of covenants and certain other matters, subject to certain exceptions and limitations. Dynegy has guaranteed, up to a maximum liability of $2.80 billion, the obligations of DRI under the Duke Midwest Purchase Agreement and related Transition Services Agreement (“TSA”). DRI shall, in the aggregate, not be entitled to indemnification in excess of $280 million for most matters and $2.80 billion for certain fundamental representations, tax matters and fraud.

Business Combination Accounting. The EquiPower Acquisition and the Duke Midwest Acquisition (collectively, the "Acquisitions") have been accounted for in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition dates, April 1, 2015 and April 2, 2015, respectively. The initial accounting for the Acquisitions is not complete because certain information and analysis that may impact our initial valuations are still being obtained or reviewed as a result of the short time period since the closing of the Acquisitions. The significant assets and liabilities for which provisional amounts are recognized at the respective acquisition dates are property, plant and equipment, intangible assets and liabilities, goodwill, investment in unconsolidated affiliate, working capital adjustments, deferred income taxes, taxes other than deferred income taxes and asset retirement obligations. The provisional amounts recognized are subject to revision until our valuations are completed, not to exceed one year, and any material adjustments identified that existed as of the acquisition date will be retroactively adjusted.

To fair value the acquired property, plant and equipment, we used a Discounted Cash Flow ("DCF") analysis, classified as Level 3 within the fair value hierarchy levels and based upon a debt-free, free cash flow model. This DCF model was created for each power generation facility based on its remaining useful life. The DCF model included gross margin forecasts for each power generation facility determined using forward commodity market prices obtained from third party quotations for the years 2015 through 2016. For the years 2017 through 2024, we used commodity and capacity price curves developed internally utilizing forward NYMEX natural gas prices and supply and demand factors. For periods beyond 2024, we assumed a 2.5 percent growth rate. We also used management's forecasts of operations and maintenance expense, general and administrative expense and capital expenditures for the years 2015 through 2019 and assumed a 2.5 percent growth rate, thereafter. The resulting cash flows were then discounted using plant specific discount rates of approximately 8 to 10 percent for gas-fired generation facilities and approximately 9 to 13 percent for coal-fired generation facilities, based upon the asset's age, efficiency, region and years until retirement. Contracts with terms that were not at current market value were also valued using a DCF analysis. The cash flows generated by the contracts were compared with their cash flows based on current market prices with the resulting difference recorded as either an intangible asset or liability. The 3,460,053 shares of common stock of Dynegy issued as part of the consideration for the EquiPower Acquisition were valued at approximately $105 million based on the closing price of Dynegy's common stock on the EquiPower Closing Date.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

The following table summarizes the consideration paid and the preliminary fair value amounts recognized for the assets acquired and liabilities assumed related to the EquiPower Acquisition and Duke Midwest Acquisition, as of the respective acquisition dates, April 1, 2015 and April 2, 2015:

(amounts in millions)	EquiPower Acquisition	Duke Midwest Acquisition	Total
Cash	$3,350	$2,800	$6,150
Equity instruments (3,460,053 common shares of Dynegy)	105	—	105
Net working capital adjustment	206	(9)	197
Fair value of total consideration transferred	$3,661	$2,791	$6,452
Cash	$267	$—	$267
Accounts receivable	50	124	174
Inventory	166	106	272
Assets from risk management activities (including current portion of $4 million and $30 million, respectively)	4	33	37
Prepayments and other current assets	32	69	101
Property, plant and equipment	2,776	2,741	5,517
Investment in unconsolidated affiliate	196	—	196
Intangible assets (including current portion of $67 million and $36 million, respectively)	111	84	195
Other long-term assets	28	34	62
Total assets acquired	3,630	3,191	6,821
Accounts payable	27	92	119
Accrued liabilities and other current liabilities	20	10	30
Debt, current portion	39	—	39
Liabilities from risk management activities (including current portion of $41 million and zero, respectively)	57	107	164
Asset retirement obligations	53	56	109
Intangible liabilities (including current portion of $24 million and $58 million, respectively)	73	93	166
Deferred income taxes, net	537	—	537
Other long-term liabilities	—	42	42
Total liabilities assumed	806	400	1,206
Identifiable net assets acquired	2,824	2,791	5,615
Goodwill	837	—	837
Net assets acquired	$3,661	$2,791	$6,452

As a result of recording the stepped up fair market basis for GAAP purposes, but receiving primarily carryover basis for tax purposes in the EquiPower Acquisition, we recorded a net deferred tax liability of $537 million. As we have previously recorded a valuation allowance against our historical deferred tax assets, we have released approximately $480 million of our valuation allowance as a result of these increased net deferred tax liabilities.

The goodwill of $837 million resulting from the EquiPower Acquisition reflects the excess of our purchase price over the fair value of the net assets acquired. We allocated 88 percent of the goodwill to our Gas reporting unit, and 12 percent to our Coal reporting unit, or $732 million and $105 million, respectively, based upon the fair value of the plant assets associated with each reporting unit. None of the goodwill recognized is deductible for income tax purposes, and as such, no deferred taxes have been recorded related to goodwill. No goodwill was recognized as a result of the Duke Midwest Acquisition.

We incurred acquisition costs of $2 million and $85 million for the three and six months ended June 30, 2015, respectively, related to the Acquisitions, which are included in Acquisition and integration costs in our unaudited consolidated statement of operations. Revenues of $585 million and operating income of $148 million attributable to the Acquisitions are included in our unaudited consolidated statement of operations for the three and six months ended June 30, 2015.

Pro Forma Results. The unaudited pro forma financial results for the six months ended June 30, 2015 and 2014 assume the EquiPower Acquisition and the Duke Midwest Acquisition occurred on January 1, 2014. 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, 2014, nor are they indicative of future results of operations.

	Six Months Ended June 30,	
(amounts in millions)	2015	2014
Revenues	$2,612	$2,696
Net income (loss)	$466	$(528)
Net income (loss) attributable to noncontrolling interests	$(3)	$5
Net income (loss) attributable to Dynegy Inc.	$469	$(533)

Note 4—Unconsolidated Investments

Equity Method Investments

Elwood. In connection with the EquiPower Acquisition, we acquired a 50 percent interest in Elwood Energy LLC, a limited liability company ("Elwood Energy") and Elwood Expansion LLC, a limited liability company ("Elwood Expansion" and, together with Elwood Energy, "Elwood"). Elwood Energy owns a 1,566 MW natural gas-fired facility located in Elwood, Illinois. As of June 30, 2015, our equity method investment included in our unaudited consolidated balance sheet was $199 million. Upon the acquisition of our Elwood investment, we recognized basis differences in the net assets of approximately $84 million related to property plant and equipment, debt and intangibles. These basis differences are being amortized over their respective useful lives. Our risk of loss related to our equity method investment is limited to our investment balance. Holders of the debt of our unconsolidated investment do not have recourse to us and our other subsidiaries; therefore, the debt of our unconsolidated investment is not reflected in our unaudited consolidated balance sheet. As of June 30, 2015, Elwood debt was approximately $160 million, and based on our pro rata share of the investment, our share of such debt would be approximately $80 million.

We recorded $3 million in equity earnings related to our investment in Elwood, which is reflected in Earnings from unconsolidated investments in our unaudited consolidated statement of operations for the three and six months ended June 30, 2015. There were no distributions for the three and six months ended June 30, 2015. In July 2015, we received a distribution of $11 million. As of June 30, 2015, we have approximately $2 million in accounts receivable due from Elwood, which is included in Accounts receivable in our unaudited consolidated balance sheet.

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.

Note 5—Risk Management Activities, Derivatives and Financial Instruments

The nature of our business necessarily involves commodity 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 and physically settled contracts consistent with our commodity risk management policy. Our treasury team manages our 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.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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 have other contractual arrangements such as capacity forward sales arrangements, tolling arrangements, fixed price coal purchases and retail power sales which 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.

Quantitative Disclosures Related to Financial Instruments and Derivatives

As of June 30, 2015, we had net purchases and sales of derivative contracts outstanding in the following quantities:

Contract Type (dollars and quantities in millions)	Quantity Purchases (Sales)	Unit of Measure	Fair Value (1) Asset (Liability)
Commodity contracts:			
Electricity derivatives (2)	(42)	MWh	$(69)
Electricity basis derivatives (3)	(51)	MWh	$60
Natural gas derivatives (2)	260	MMBtu	$(131)
Natural gas basis derivatives	62	MMBtu	$(29)
Diesel fuel derivatives	5	Gallon	$(4)
Coal derivatives	—	Metric Ton	$(39)
Heat rate derivatives	4	MWh/MMBtu	$(7)
Emissions derivatives	6	Metric Ton	$2
Interest rate swaps	781	U.S. Dollar	$(44)
Common stock warrants (4)	16	Warrant	$(63)

(1) Includes both asset and liability risk management positions, but excludes margin and collateral netting of $105 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, 2015 and December 31, 2014. As of June 30, 2015 and December 31, 2014, there were no gross amounts available to be offset that were not offset in our unaudited consolidated balance sheets.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

		June 30, 2015			
			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	$445	$(345)	$—	$100
Total derivative assets		$445	$(345)	$—	$100
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(662)	$345	$105	$(212)
Interest rate contracts	Liabilities from risk management activities	(44)	—	—	(44)
Common stock warrants	Other long-term liabilities	(63)	—	—	(63)
Total derivative liabilities		$(769)	$345	$105	$(319)
Total derivatives		$(324)	$—	$105	$(219)

		December 31, 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	$115	$(35)	$—	$80
Total derivative assets		$115	$(35)	$—	$80
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(163)	$35	$9	$(119)
Interest rate contracts	Liabilities from risk management activities	(44)	—	—	(44)
Common stock warrants	Other long-term liabilities	(61)	—	—	(61)
Total derivative liabilities		$(268)	$35	$9	$(224)
Total derivatives		$(153)	$—	$9	$(144)

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, 2015 was $81 million, for which we have posted $7 million collateral. Our remaining derivative instruments do not have credit-related collateral contingencies as they are included within our first-lien collateral program.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

The following table summarizes our total cash collateral posted as of June 30, 2015 and December 31, 2014, along with the location on the balance sheet and the amount applied against our short-term risk management liabilities.

Location on balance sheet	June 30, 2015	December 31, 2014
(amounts in millions)		
Gross collateral posted with counterparties	$166	$49
Less: Collateral netted against risk management liabilities	105	9
Net collateral within Prepayments and other current assets	$61	$40

Impact of Derivatives on the Unaudited 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 our unaudited consolidated statements of operations.

Our unaudited consolidated statements of operations for the three and six months ended June 30, 2015 and 2014 include the impact of derivative financial instruments as presented below.

Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30,		Six Months Ended June 30,	
		2015	2014	2015	2014
(amounts in millions)					
Commodity contracts	Revenues	$53	$(36)	$72	$(209)
Interest rate contracts	Interest expense	$1	$(10)	$(8)	$(7)
Common stock warrants	Other income (expense), net	$3	$(43)	$(2)	$(49)

Note 6—Fair Value Measurements

We apply the market approach for recurring fair value measurements, employing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We have consistently used the same valuation techniques for all periods presented. Please read Note 2—Summary of Significant Accounting Policies—Fair Value Measurements in our Form 10-K for further discussion.

The following tables set forth, by level within the fair value hierarchy, are financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014 and are presented on a gross basis before consideration of amounts netted under master netting agreements and the application of collateral and margin paid.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

	Fair Value as of June 30, 2015			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$310	$84	$394
Natural gas derivatives	—	39	5	44
Emissions derivatives	—	2	—	2
Coal derivatives	—	1	4	5
Total assets from commodity risk management activities	$—	$352	$93	$445
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(265)	$(138)	$(403)
Natural gas derivatives	—	(188)	(16)	(204)
Heat rate derivatives	—	—	(7)	(7)
Diesel fuel derivatives	—	(4)	—	(4)
Coal derivatives	—	(44)	—	(44)
Total liabilities from commodity risk management activities	—	(501)	(161)	(662)
Liabilities from interest rate contracts	—	(44)	—	(44)
Liabilities from outstanding common stock warrants	(63)	—	—	(63)
Total liabilities	$(63)	$(545)	$(161)	$(769)

	Fair Value as of December 31, 2014			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$88	$22	$110
Natural gas derivatives	—	3	—	3
Emissions derivatives	—	2	—	2
Total assets from commodity risk management activities	$—	$93	$22	$115
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(27)	$(26)	$(53)
Natural gas derivatives	—	(100)	—	(100)
Diesel derivatives	—	(6)	—	(6)
Crude oil derivatives	—	(3)	—	(3)
Coal derivatives	—	(1)	—	(1)
	—	(137)	(26)	(163)

Total liabilities from commodity risk management activities				
Liabilities from interest rate contracts	—	(44)	—	(44)
Liabilities from outstanding common stock warrants	(61)	—	—	(61)
Total liabilities	$(61)	$(181)	$(26)	$(268)

15

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Level 3 Valuation Methods. The electricity derivatives classified within Level 3 include financial swaps executed in illiquid trading locations or on long dated contracts, capacity contracts, 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. 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 correlation values. The natural gas derivatives classified within Level 3 include financial swaps, basis swaps and physical purchases executed in illiquid trading locations or on long dated contracts. The coal derivatives classified within Level 3 include financial swaps executed in illiquid trading locations.

Sensitivity to Changes in Significant Unobservable Inputs for Level 3 Valuations. The significant unobservable inputs used in the fair value measurement of our commodity instruments categorized within Level 3 of the fair value hierarchy include estimates of forward congestion, power price spreads, natural gas and coal pricing and the difference between our plant locational prices to liquid hub prices. Power price spreads, natural gas and coal pricing and the difference between our plant locational prices to liquid hub prices 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 of the spread on a buy or sell 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, 2015 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)	(2)	Million MWh	$(43)	Basis spread + liquid location	Basis spread	$5.00 - $7.00
FTRs	45	Million MWh	$(11)	Historical congestion	Forward price	$0.00 - $4.00
Heat rate derivatives:	(1)	Million MWh	$5	Option model	Gas/power price correlation	24% - 44%
	5	Million MMBtu	$(12)	Option model	Power price volatility	70% - 100%
Natural gas derivatives (1)	33	Million MMBtu	$(11)	Illiquid location fixed price	Forward price	$1.80 - $2.20
Coal derivatives (1)	(110)	Thousand Tons	$4	Illiquid location fixed price	Forward price	$6.80 - $8.30

(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:

(amounts in millions)	Three Months Ended June 30, 2015 Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at March 31, 2015	$4	$—	$—	$—	$4
Acquisitions	(54)	(14)	(9)	5	(72)

Total gains included in earnings	(2)	3	—	—	1
Settlements (1)	(2)	—	2	(1)	(1)
Balance at June 30, 2015	$(54)	$(11)	$(7)	$4	$(68)
Unrealized gains relating to instruments held as of June 30, 2015	$(2)	$3	$—	$—	$1

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

	Six Months Ended June 30, 2015				
(amounts in millions)	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at December 31, 2014	$(4)	$—	$—	$—	$(4)
Acquisitions	(54)	(14)	(9)	5	(72)
Total losses included in earnings	1	3	—	—	4
Settlements (1)	3	—	2	(1)	4
Balance at June 30, 2015	$(54)	$(11)	$(7)	$4	$(68)
Unrealized losses relating to instruments held as of June 30, 2015	$1	$3	$—	$—	$4

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

	Six Months Ended June 30, 2014		
(amounts in millions)	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)
Unrealized losses relating to instruments held as of June 30, 2014	$(22)	$—	$(22)

---

(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 in our 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, 2015 and 2014.

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, 2015 and 2014, other than the preliminary purchase price allocation discussed in Note 3—Acquisitions.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Fair Value of Financial Instruments. The following table discloses the fair value of financial instruments recognized on our unaudited consolidated 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, 2015 and December 31, 2014, respectively.

(amounts in millions)	June 30, 2015 Carrying Amount	June 30, 2015 Fair Value	December 31, 2014 Carrying Amount	December 31, 2014 Fair Value
Dynegy Inc.:				
6.75% Senior Notes, due 2019 (2)(6)	$(2,100)	$(2,184)	$(2,100)	$(2,132)
Tranche B-2 Term Loan, due 2020 (1)(2)	$(781)	$(786)	$(785)	$(775)
7.375% Senior Notes, due 2022 (2)(6)	$(1,750)	$(1,833)	$(1,750)	$(1,777)
5.875% Senior Notes, due 2023 (2)	$(500)	$(486)	$(500)	$(475)
7.625% Senior Notes, due 2024 (2)(6)	$(1,250)	$(1,319)	$(1,250)	$(1,272)
Inventory financing agreements (2)	$(45)	$(45)	$(23)	$(23)
Interest rate derivatives (2)	$(44)	$(44)	$(44)	$(44)
Commodity-based derivative contracts (3)	$(217)	$(217)	$(48)	$(48)
Common stock warrants (4)	$(63)	$(63)	$(61)	$(61)
Genco:				
7.00% Senior Notes Series H, due 2018 (2)(5)	$(272)	$(290)	$(268)	$(264)
6.30% Senior Notes Series I, due 2020 (2)(5)	$(209)	$(229)	$(206)	$(208)
7.95% Senior Notes Series F, due 2032 (2)(5)	$(224)	$(257)	$(224)	$(241)

(1) Carrying amount includes an unamortized discount of $3 million as of June 30, 2015 and December 31, 2014. Please read Note 13—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 $105 million and $9 million of cash posted as collateral, as of June 30, 2015 and December 31, 2014, 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, 2015 and December 31, 2014 include unamortized discounts of $120 million and $127 million, respectively. Please read Note 13—Debt for further discussion.
(6) At December 31, 2014, these debt agreements were held by Dynegy Finance I and Dynegy Finance II. Upon the closing of the Acquisitions, the Dynegy Finance I and Dynegy Finance II notes were exchanged for an equal aggregate principal amount of notes with the same terms issued by Dynegy (the “Notes”).

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Note 7—Accumulated Other Comprehensive Income

Changes in accumulated other comprehensive income, net of tax, by component is as follows:

	Six Months Ended June 30,	
(amounts in millions)	2015	2014
Beginning of period	$20	$58
Other comprehensive loss before reclassifications:		
Actuarial loss (net of tax of zero and zero, respectively)	(5)	(2)
Amounts reclassified from accumulated other comprehensive income:		
Amortization of unrecognized prior service credit and actuarial gain (net of tax of zero and zero, respectively) (1)	(1)	(2)
Net current period other comprehensive loss, net of tax	(6)	(4)
End of period	$14	$54

(1) 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 (gain). Please read Note 16—Pension and Other Post-Employment Benefit Plans for further discussion.

Note 8—Inventory

A summary of our inventories is as follows:

(amounts in millions)	June 30, 2015	December 31, 2014
Materials and supplies	$176	$83
Coal (1)	266	119
Fuel oil (1)	8	3
Emissions allowances	72	2
Other	1	1
Total	$523	$208

(1) As of June 30, 2015, approximately $33 million and $7 million of the coal and fuel oil inventory, respectively, are part of an inventory financing arrangement. Please read Note 13—Debt—Brayton Point Inventory Financing Facility for further discussion.

Note 9—Property, Plant and Equipment

A summary of our property, plant and equipment is as follows:

(amounts in millions)	June 30, 2015	December 31, 2014
Power generation	$6,657	$2,248
Environmental upgrades	1,656	926
Buildings and improvements	898	457
Office and other equipment	98	54
Property, plant and equipment	9,309	3,685
Accumulated depreciation	(643)	(430)
Property, plant and equipment, net	$8,666	$3,255

Note 10—Joint Ownership of Generating Facilities

We hold ownership interests in certain jointly owned generating facilities. We are entitled to the proportional share of the generating capacity and the output of each unit equal to our ownership interests. We pay our share of capital expenditures,

19

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs. Our share of revenues and operating costs of the jointly owned generating facilities are included within the corresponding financial statement line items in our unaudited consolidated statement of operations.

The following table presents the ownership interests of the jointly owned facilities included in the unaudited consolidated balance sheet.

	June 30, 2015				
(dollars in millions)	Ownership Interest	Property, Plant and Equipment	Accumulated Depreciation	Construction Work in Progress	Total
Miami Fort (Units 7 and 8) (1)	64.0 %	$251	$(6)	$6	$251
J.M. Stuart (2)(3)	39.0 %	$27	$(1)	$9	$35
Conesville (Unit 4) (2)(3)	40.0 %	$41	$—	$2	$43
W.H. Zimmer (2)	46.5 %	$156	$(4)	$8	$160
Killen Station (1)(3)	33.0 %	$1	$—	$1	$2

(1) Co-owned with The Dayton Power and Light Company.
(2) Co-owned with The Dayton Power and Light Company and AEP Generation Resources Inc.
(3) Facilities not operated by Dynegy.

Note 11—Intangible Assets and Liabilities

The following table summarizes the components of our intangible assets and liabilities as of June 30, 2015 and December 31, 2014:

	June 30, 2015			December 31, 2014		
(amounts in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Intangible Assets:						
Electricity contracts	$262	$(76)	$186	$111	$(46)	$65
Coal contracts	—	—	—	—	—	—
Gas transport contracts	44	(2)	42	—	—	—
Total intangible assets	$306	$(78)	$228	$111	$(46)	$65
Intangible Liabilities:						
Electricity contracts	$(30)	$12	$(18)	$(20)	$14	$(6)
Coal contracts	(134)	45	(89)	(41)	22	(19)
Coal transport contracts	(104)	47	(57)	(81)	32	(49)
Gas transport contracts	(64)	22	(42)	(24)	17	(7)
Total intangible liabilities	$(332)	$126	$(206)	$(166)	$85	$(81)
Intangible assets and liabilities, net	$(26)	$48	$22	$(55)	$39	$(16)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

The following table presents our amortization expense (revenue) of intangible assets and liabilities for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
(amounts in millions)	2015	2014	2015	2014
Electricity contracts, net (1)	$25	$32	$32	$61
Coal contracts, net (2)	(20)	(4)	(23)	(8)
Coal transport contracts, net (2)	(9)	(7)	(15)	(14)
Gas transport contracts, net (2)	(1)	(2)	(3)	(4)
Total	$(5)	$19	$(9)	$35

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

The following table summarizes the components of our contract based intangible assets and liabilities recorded in connection with the Acquisitions in April 2015:

	EquiPower Acquisition		Duke Midwest Acquisition	
(amounts in millions/months)	Gross Carrying Amount	Weighted-Average Amortization Period	Gross Carrying Amount	Weighted-Average Amortization Period
Intangible Assets:				
Electricity contracts	$71	32	$80	38
Coal contracts	—	0	—	9
Gas transport contracts	40	24	4	19
Total intangible assets	$111	29	$84	37
Intangible Liabilities:				
Electricity contracts	$—	0	$(10)	23
Coal contracts	(10)	21	(83)	27
Coal transport contracts	(23)	22	—	0
Gas contracts	—	1	—	0
Gas transport contracts	(40)	128	—	0
Total intangible liabilities	$(73)	81	$(93)	27
Total intangible assets and liabilities, net	$38		$(9)	

Amortization expense (revenue), net related to intangible assets and liabilities recorded in connection with the Acquisitions for the next five years as of June 30, 2015 is as follows: 2015—$7 million, 2016—$26 million, 2017—$19 million, 2018—$1 million and 2019—$(3) million.

Note 12—Asset Retirement Obligation

We record the present value of our legal obligations to retire tangible, long-lived assets on our balance sheets as liabilities when the liability is incurred. A summary of changes in our asset retirement obligations is as follows:

(amounts in millions)	June 30, 2015
Balance, December 31, 2014	$224
Accretion expense	9
Liabilities settled in the current period	(4)
Acquisitions	109
Balance, June 30, 2015	$338

21

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Note 13—Debt
A summary of our long-term debt is as follows:

(amounts in millions)	June 30, 2015	December 31, 2014
Dynegy Inc.:		
6.75% Senior Notes, due 2019 (1)	$2,100	$2,100
Tranche B-2 Term Loan, due 2020	784	788
7.375% Senior Notes, due 2022 (1)	1,750	1,750
5.875% Senior Notes, due 2023	500	500
7.625% Senior Notes, due 2024 (1)	1,250	1,250
Revolving Facility	—	—
Inventory Financing Agreements	45	23
Genco:		
7.00% Senior Notes Series H, due 2018	300	300
6.30% Senior Notes Series I, due 2020	250	250
7.95% Senior Notes Series F, due 2032	275	275
	7,254	7,236
Unamortized discounts on debt, net	(123)	(130)
	7,131	7,106
Less: Current maturities, including unamortized discounts, net	52	31
Total Long-term debt	$7,079	$7,075

---

(1) At December 31, 2014, these debt agreements were held by Dynegy Finance I and Dynegy Finance II. Upon the closing of the Acquisitions, the Dynegy Finance I and Dynegy Finance II notes were exchanged for an equal aggregate principal amount of notes with the same terms issued by Dynegy (the "Notes").

Debt Issuance

On October 27, 2014, Dynegy Finance II, Inc. (the "EquiPower Escrow Issuer"), a wholly-owned subsidiary of Dynegy, issued $3.06 billion in aggregate principal amount of senior notes, the proceeds of which were placed into escrow until the closing of the EquiPower Acquisition. On the EquiPower Closing Date, the proceeds from the issuance were released from escrow and used to pay a portion of the EquiPower Acquisition consideration and to pay fees and expenses. On the EquiPower Closing Date, Dynegy, as successor in interest to the EquiPower Escrow Issuer, executed supplemental indentures evidencing its accession to the 6.75 percent senior notes due 2019 (the "2019 Finance II Notes"), the 7.375 percent senior notes due 2022 (the "2022 Finance II Notes"), and the 7.625 percent senior notes due 2024 (the "2024 Finance II Notes" and, together with the 2019 Finance II Notes and the 2022 Finance II Notes, the "Finance II Notes").

Further, on October 27, 2014, Dynegy Finance I, Inc. (the "Duke Escrow Issuer"), a wholly-owned subsidiary of Dynegy, issued $2.04 billion in aggregate principal amount of senior notes, the proceeds of which were placed into escrow until the closing of the Duke Midwest Acquisition. On the Duke Midwest Closing Date, the proceeds from the issuance were released from escrow and used to pay a portion of the Duke Midwest Acquisition consideration and to pay fees and expenses. On the Duke Midwest Closing Date, Dynegy, as successor in interest to the Duke Escrow Issuer, executed supplemental indentures evidencing its accession to the 6.75 percent senior notes due 2019 (the "2019 Finance I Notes"), the 7.375 percent senior notes due 2022 (the "2022 Finance I Notes"), and the 7.625 percent senior notes due 2024 (the "2024 Finance I Notes" and, together with the 2019 Finance I Notes and the 2022 Finance I Notes, the "Finance I Notes"). Concurrently with Dynegy's accession to the Finance I Notes, as successor in interest to the Duke Escrow Issuer, each series of Finance I Notes was automatically exchanged for an equal aggregate principal amount of Finance II Notes with the same terms, as applicable, issued by Dynegy. The additional Finance II Notes issued pursuant to such automatic exchanges were treated as a single class for all purposes and are fully fungible with the

Finance II Notes with the same terms previously issued under the Finance II indentures.

On the EquiPower Closing Date, generally, each of Dynegy's current wholly-owned domestic subsidiaries that is a borrower or guarantor under Dynegy's existing credit facilities (the "Dynegy Guarantors"), and the entities acquired in the

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

EquiPower Acquisition (the “EquiPower Guarantors”) executed supplemental indentures evidencing their accession to the Finance II Notes as guarantors. Similarly, on the Duke Midwest Closing Date, each of Dynegy’s current wholly-owned domestic subsidiaries that is a borrower or guarantor under Dynegy’s existing credit facilities and the entities acquired in the Duke Midwest Acquisition (the “Duke Guarantors” and, together with the Dynegy Guarantors and the EquiPower Guarantors, the “Guarantors”) executed supplemental indentures evidencing their accession to the Finance I Notes and the Finance II Notes as guarantors.

On the EquiPower Closing Date, the Dynegy Guarantors and the EquiPower Guarantors executed a joinder to the registration rights agreement, dated October 27, 2014, among the EquiPower Escrow Issuer, the Duke Escrow Issuer, and Morgan Stanley & Co. LLC, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, RBC Capital Markets, LLC and UBS Securities LLC as representatives of the initial purchasers identified therein (the “Registration Rights Agreement”). Additionally, on the Duke Midwest Closing Date, the Duke Guarantors executed a joinder to the Registration Rights Agreement.

As required by the Registration Rights Agreement, on July 17, 2015 Dynegy commenced registered exchange offers for the Notes which close at 5:00 p.m., New York City time, on August 17, 2015, unless extended by Dynegy. The exchange offers are being made only pursuant to the prospectus dated July 17, 2015 and the accompanying letter of transmittal and only to such persons and in such jurisdictions as is permitted under applicable law.

Credit Agreement

As of June 30, 2015, we had a $2.225 billion credit agreement that consisted of (i) an $800 million seven-year senior secured term loan B facility (the “Tranche B-2 Term Loan”) and (ii) a $1.425 billion 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 (as defined in the Credit Agreement) 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. Following the closings of the Acquisitions in April 2015, the acquired entities were added as additional subsidiary guarantors.

At June 30, 2015, there were no amounts drawn on the Revolving Facility; however, we had outstanding letters of credit of approximately $470 million, which reduce 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 were in compliance at June 30, 2015.

Credit Agreement Amendments. On the EquiPower Closing Date, Dynegy entered into a First Amendment to the Credit Agreement (the “First Amendment”) among Dynegy, certain subsidiaries of Dynegy, the lenders party thereto, Credit Suisse AG, Cayman Islands Branch (“Credit Suisse”), as administrative agent, and the other parties thereto. The First Amendment provides for a new $350 million five-year senior secured incremental tranche of revolving commitments (the “Incremental Tranche A Revolving Loan Commitments”), which have terms substantially the same as the terms of the outstanding tranche of revolving loans under the Credit Agreement and will mature on April 1, 2020. Amounts available under the Incremental Tranche A Revolving Loan Commitments are available on a revolving basis, and such amounts that are repaid or prepaid may be re-borrowed. The loans issued pursuant to the Incremental Tranche A Revolving Loan Commitments bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio (as such terms are defined in the Credit Agreement).

Further on the Duke Midwest Closing Date, Dynegy entered into a Second Amendment to the Credit Agreement (the “Second Amendment”) among the Company, certain subsidiaries of Dynegy, the lenders party thereto, Credit Suisse, as administrative agent, and the other parties thereto. The Second Amendment provides for a new $600 million five-year senior secured incremental tranche of revolving commitments (the “Incremental Tranche B Revolving Loan Commitments”), which have terms substantially the same as the terms of the outstanding tranche of revolving loans

under the Credit Agreement and will mature on April 2, 2020. Amounts available under the Incremental Tranche B Revolving Loan Commitments are available on a revolving basis, and such amounts that are repaid or prepaid may be re-borrowed. The loans issued pursuant to the Incremental Tranche B Revolving Loan Commitments bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio (as such terms are defined in the Credit Agreement).
Subsequent to the First Amendment and Second Amendment, we have three tranches of revolvers: (i) $475 million tranche which will mature on April 23, 2018, (ii) $350 million tranche which will mature April 1, 2020 and (iii) $600 million tranche which will mature on April 2, 2020.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Genco Senior Notes

On December 2, 2013, in connection with the acquisition of New Ameren Energy Resources, LLC ("AER"), 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 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, 2015 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.

Inventory Financing Agreements

Brayton Point Inventory Financing. In connection with the EquiPower Acquisition, we assumed an inventory financing arrangement (the "Inventory Financing Arrangement") for coal and fuel oil inventories at our Brayton Point facility, consisting of a debt obligation for existing and subsequent inventories, as well as a $15 million line of credit. Balances on the line of credit in excess of the $15 million line of credit are cash collateralized. This Inventory Financing Arrangement terminates, and our obligation becomes due and payable, on May 31, 2017, and is secured by a guaranty from Dynegy. As of June 30, 2015, our line of credit balance was $20.8 million, of which approximately $5.8 million was collateralized by cash and included in Prepayments and other current assets on our unaudited consolidated balance sheets.

As the materials are purchased and delivered to our facilities, our debt obligation and line of credit increase based on the then market rate of the materials, transportation cost, and other expenses. The debt obligation increases for 85 percent of the total price of the coal and 90 percent for the total price of fuel oil. The line of credit increases for the remaining 15 percent and 10 percent for coal and oil, respectively. Upon consuming the materials, we repay the debt obligation and line of credit at the then market price, as defined within the Inventory Financing Agreement for the amount of the materials consumed on a weekly basis.

The line of credit bears interest at an annual interest rate of the 3-month LIBOR plus 8 percent. An availability fee is calculated on a per annum rate of 0.75 percent. As of June 30, 2015, the line of credit bears interest at 8.27 percent.

Emissions Repurchase Agreements. In 2013, we entered into two repurchase transactions with a third party in which we sold $6 million in California Carbon Allowance ("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 of RGGI inventory and received cash. In October 2014, we repurchased all $6 million of the previously sold CCA credits and in February 2015, we repurchased all $23 million of the previously sold RGGI inventory.

24

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Letter of Credit Facilities

On January 29, 2014, Illinois Power Marketing Company ("IPM") entered into a fully cash collateralized Letter of Credit and Reimbursement Agreement with an issuing bank, as amended on May 16, 2014 ("LC Agreement"), pursuant to which the issuing 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 the issuing bank an amount of cash sufficient to cover the face value of such requested letter of credit plus an additional percentage thereon. As of June 30, 2015, IPM had $10.5 million deposited with the issuing bank and approximately $2 million in letters of credit outstanding.

On September 18, 2014, Dynegy entered into a Letter of Credit Reimbursement Agreement with an issuing bank, and its affiliate (the "Lender"), for a letter of credit in an amount not to exceed $55 million. The facility has a one-year tenor and may be extended at the Lender's option up to one additional year. At June 30, 2015, there was $55 million outstanding under this letter of credit.

On March 27, 2015, IPM entered into a letter of credit facility with the Lender for up to $25 million. The facility, which is collateralized by receivables, has a two-year tenor and may be extended if agreed to by both parties for one additional year. Interest on the facility is LIBOR plus 500 basis points on issued letters of credit. At June 30, 2015, there was $20 million outstanding under this letter of credit facility.

Interest Rate Swaps

Subsequent to executing the Credit Agreement and issuing the Senior Notes, we amended our interest rate swaps to more closely match the terms of our Tranche B-2 Term Loan. The swaps have an aggregate notional value of approximately $781 million at an average fixed rate of 3.19 percent with a floor of one percent and expire during the second quarter 2020. In lieu of paying the breakage fees related to terminating the old swaps and issuing the new swaps, the costs were incorporated into the terms of the new swaps. As a result, any cash flows related to the settlement of the new swaps are reflected as a financing activity in our unaudited consolidated statement of cash flows.

Note 14—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 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 Dynegy Holdings, LLC Debtor Entities and their non-debtor affiliates in 2011 (the "2011 Prepetition Restructuring"), and specifically the transfer of Dynegy Midwest Generation, LLC ("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

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

"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 October 31, 2014, the Second Circuit affirmed the District Court's dismissal based upon the lead plaintiff's lack of standing. The lead plaintiff did not appeal to the U.S. Supreme Court.

Additionally, on July 19, 2013, the defendants filed a substantive motion to dismiss the plaintiff's remaining claims by any opt-out plaintiffs against the non-debtor defendants. On April 30, 2014, the District Court granted the defendants' motion and dismissed the action. On June 25, 2015, the Second Circuit Court affirmed the District Court's dismissal.

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 April 21, 2015, the Supreme Court issued its opinion affirming the Ninth Circuit's decision and remanding the matter to the Nevada District Court for further proceedings.

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. The Texas Supreme Court denied rehearing on August 22, 2014. On November 20, 2014, PPE initiated a new arbitration against IGC and its co-respondents, but the Dallas District Court enjoined the arbitration from proceeding against IGC while any dispute over the escrow account remains pending. On December 16, 2014, the Dallas District Court entered a judgment requiring a full distribution of the escrow account to IGC and an additional $2.5 million in interest. PPE paid the $17 million principal to IGC from the escrow account, but filed a notice of appeal regarding the $17 million and $2.5 million interest judgment in March 2015.

Other Contingencies

MISO 2015-2016 Planning Resource Auction Complaints. In May of 2015, three complaints were filed at FERC regarding the Zone 4 results for the 2015-2016 Planning Resource Auction ("PRA") conducted by MISO. Dynegy is a named party in one of the complaints. The complainants, Public Citizen, Inc., the Illinois Attorney General, and Southwestern Electric Cooperative, Inc., have challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds and requested changes to the MISO PRA structure going forward. Complainants have also alleged that Dynegy may have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the 2015-2016 PRA. The Independent Market Monitor for MISO ("MISO IMM"), which was responsible for monitoring the MISO 2015-2016 PRA, determined that all offers were competitive and that no physical or economic withholding occurred. The MISO IMM also stated, in a filing responding to the complaints, that there is no basis for the proposed remedies. Dynegy complied fully with the terms of the MISO Tariff in connection with the 2015-2016 PRA, disputes the allegations and will defend its actions vigorously. Dynegy filed an Answer to these complaints. In addition, the Illinois Industrial Energy Consumers filed a complaint at FERC against MISO on June 30, 2015 requesting prospective changes to the MISO tariff. Dynegy also responded to this complaint.

Dam Safety Assessment Reports. In response to the failure at the Tennessee Valley Authority's Kingston plant, the EPA initiated a nationwide investigation of the structural integrity of coal combustion residual ("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.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

In response to the Hennepin report, we notified the EPA in July 2013 of our intent to close the Hennepin west CCR surface impoundment and make certain capital improvements to the east 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 asset retirement obligation ("ARO") by approximately $2 million during the second quarter 2013. We performed further studies needed to support closure of the west CCR surface impoundment and submitted them to the Illinois EPA in August 2014. The capital improvements to the Hennepin east CCR surface impoundment berms were completed in 2014 at a cost of approximately $3 million.

In response to the Baldwin report, we notified the EPA in April 2013 of our action plan, which included implementation of recommended operating practices and certain recommended studies. In 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. In the first quarter 2015, we submitted to the EPA engineering design information concerning repairs of the affected south berm at the Baldwin CCR surface impoundment and a deformation analysis of the Baldwin CCR surface impoundment's north berm. 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 would be approximately $3 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 New Source Review and New Source Performance Standard 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.

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 ("NOV") alleging that projects performed in 1997, 2006 and 2007 at the Newton facility violated Prevention of Significant Deterioration, Title V permitting and other requirements. We believe our defenses to the allegations described in the NOV are meritorious. A decision by the U.S. Court of Appeals for the Seventh Circuit in 2013 held that similar claims older than five years were barred by the statute of limitations. This decision may provide an additional defense to the allegations in the Newton facility NOV.

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 facility's compliance with the Illinois State Implementation Plan ("SIP") and associated permits. We responded to the EPA's request and believe that there are no issues with Wood River's compliance, but we are unable to predict the EPA's response, if any.

CAA Notices of Violation. In December 2014, the EPA issued a NOV alleging violation of opacity standards at the Zimmer facility, which we co-own and operate for the owners. The EPA previously had issued NOVs to Zimmer in 2008 and 2010 alleging violations of the CAA, the Ohio SIP and the station's air permits involving standards applicable to opacity, SO_2, sulfuric acid mist and heat input. The NOVs remain unresolved. In December 2014, the EPA also issued NOVs alleging violations of opacity standards at the co-owned Stuart and Killen facilities, which are operated by The Dayton Power and Light Company. 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 the NOV matters at the Zimmer, Stuart and Killen facilities.

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. The District Court has scheduled the trial date for May 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.

Ultimate resolution of these CAA matters could have a material adverse impact on our 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.

Stuart NPDES Permit Appeal. In January 2013, the Ohio EPA issued a final National Pollutant Discharge Elimination System ("NPDES") renewal permit for the co-owned Stuart facility. The operator of Stuart, The Dayton Power and Light Company, appealed various aspects of the final permit, including provisions regarding thermal discharge limitations, to the Ohio Environmental Review Appeals Commission. A hearing before the Commission is scheduled for August 2015. Depending on the outcome of the appeal, the effects on Stuart's operations could be material. 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.

Vermilion and Baldwin Groundwater. In response to requests by the Illinois EPA, we have implemented hydrogeologic investigations for the CCR surface impoundment at our Baldwin facility and for two CCR surface impoundments at our Vermilion facility.

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. The cause of the exceedances is uncertain. If offsite groundwater impacts 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 (i.e., the old east CCR surface impoundment and the north CCR surface impoundment). The proposed corrective action plans reflect the results of a hydrogeologic investigation, which indicate that the facility's old east and north CCR surface 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 surface 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 CCR surface impoundment at Vermilion. Our estimated cost of the recommended closure alternative for both the Vermilion old east and north CCR surface impoundments, including post-closure care, is approximately $10 million. The Vermilion facility also has a third CCR surface impoundment, the new east CCR surface 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 CCR surface impoundment by removing its CCR contents concurrent with the recommended closure alternative for the old east and north CCR surface 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 September 2014, the Illinois EPA requested additional analyses concerning the closure plans for the Vermilion old east and north CCR surface impoundments. In June 2015, we advised the Illinois EPA that the additional analyses would be performed after receipt of a riverbank stabilization permit from the U.S. Army Corps of Engineers. 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 Baldwin out-of-service east CCR surface impoundment begin and that a geotechnical investigation of the existing soil cap on the Baldwin out-of-service old east CCR surface impoundment be undertaken. In October 2014, we submitted a supplemental groundwater modeling report to the Illinois EPA that indicates no known offsite water supply wells will be impacted under the various Baldwin CCR surface impoundment closure scenarios modeled. At this time we cannot reasonably estimate the costs of resolving these groundwater issues, 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.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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 addition, in April 2015, we submitted an assessment monitoring report to the Illinois EPA concerning previously reported groundwater quality standard exceedances at the Newton facility's active CCR landfill. The report identifies the Newton facility's inactive unlined landfill as the likely source of the contamination and recommends various measures to minimize the effects of that source on the groundwater monitoring results of the active landfill. The Illinois EPA also has required assessment monitoring at the Duck Creek facility's active CCR landfill, with the findings of that assessment, including proposed remedial action, if any, due in September 2015.

In April 2013, Ameren Energy Resources Company filed a proposed site-specific rulemaking with the IPCB which, if approved, would provide for the systematic and eventual closure of its CCR surface impoundments that impact groundwater in exceedance of applicable groundwater standards. In October 2013, the Illinois EPA filed a proposed rulemaking with the IPCB that would establish processes governing monitoring, corrective action and closure of CCR surface impoundments at all power generating facilities in Illinois. The site-specific rulemaking proposal, which now covers IPH CCR surface impoundments, 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 IPH groundwater 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.

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 liquefied petroleum gas vessel charters. The following describes the more significant commitments outstanding at June 30, 2015.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. Recently we have undertaken several measures to restructure our existing maintenance agreements as well as negotiate new long-term maintenance service agreements with proven turbine service providers. The term of these 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, 2015, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $359 million and $434 million in the event all contracts are terminated by us or the counterparty, respectively.

Coal Commitments. During the six months ended June 30, 2015, we entered into or assumed through our Acquisitions new long term contracts to purchase coal for our generation facilities with aggregate minimum commitments of $482 million. To the extent forecasted volumes have not been priced but are subject to a price collar structure, the obligations have been calculated using the minimum purchase price of the collar.

Coal Transportation. During the six months ended June 30, 2015, we executed or assumed through our Acquisitions new long term coal transportation contracts for our generation facilities with aggregate minimum commitments of $366 million.

Gas Transportation. During the six months ended June 30, 2015, we assumed through our Acquisitions firm capacity payment obligations related to transportation of natural gas. Such arrangements are routinely used in the physical movement and storage of energy. The total of such obligations was $153 million.

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 annually, through September 2016, at the option of the counterparty. The primary term of the second charter was through September 2014 but has been extended through September 2016 at the option of the counterparty. The first charter will terminate at the end of September 2016, and the second charter has one optional one-year extension remaining. 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, 2015 and 2016, respectively. To date, the subsidiary of Transammonia Inc. has complied with the terms of the sub-charter agreement and has not exercised the remaining optional extension.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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.

LS Power Indemnities. In connection with the 2009 transaction with LS Power, we agreed to indemnify LS Power against claims regarding any breaches in our representations and warranties and certain other potential liabilities. Even though Dynegy was discharged from any claims pursuant to the order confirming the Plan (the "Confirmation Order"), Dynegy Power Generation Inc., Dynegy Power, LLC ("DPC"), DMG and Dynegy Power Marketing, LLC remain jointly and severally liable for any indemnification claims. 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. We have accrued no amounts with respect to the indemnifications as of June 30, 2015 because none were probable of occurring, nor could they be reasonably estimated.

EquiPower Acquisition. In connection with the ECP Purchase Agreements, the ECP Purchasers agreed to indemnify the ECP Sellers against claims regarding breaches in the covenants and representations and warranties of the ECP Purchasers and certain other potential liabilities. The indemnification obligations of the ECP Purchasers shall survive for one year for most covenants and representations and warranties of the ECP Purchasers, two years for fundamental representations, and indefinitely for certain other matters. The ECP Sellers shall, in the aggregate, not be entitled to indemnification in excess of $276 million. We have accrued no amounts with respect to this indemnification as of June 30, 2015 because none were probable of occurring, nor could they be reasonably estimated. Please read Note 3—Acquisitions for further discussion.

Duke Midwest Acquisition. In connection with the Duke Midwest Purchase Agreement, Dynegy Resource I, LLC ("DRI") agreed to indemnify Duke Energy against claims regarding breaches in the covenants and representations and warranties of DRI and certain other potential liabilities. The indemnification obligations of DRI shall survive for one year for most covenants and representations and warranties of DRI, three years for fundamental representations, 30 days after the applicable statute of limitations for certain tax matters, and indefinitely for certain other matters. We have accrued no amounts with respect to this indemnification as of June 30, 2015 because none were probable of occurring, nor could they be reasonably estimated. Dynegy has guaranteed, up to maximum liability of $2.80 billion, the obligations of DRI under the Duke Midwest Purchase Agreement and related TSA. Please read Note 3—Acquisitions for further discussion.

Limited Guaranty. In connection with the acquisition of AER, 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 Corporation ("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. We have accrued no amounts with respect to the guaranty as of June 30, 2015 because none were probable of occurring, nor could they be reasonably estimated.

Note 15—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.

As of June 30, 2015, we continued to maintain a valuation allowance against our net deferred tax assets in each jurisdiction as they arise as there was not sufficient evidence to overcome our historical cumulative losses to conclude that it is more-likely-than-not our net deferred tax assets can be realized in the future. We released $480 million of our valuation allowance as a result of increased net deferred tax liabilities related to the EquiPower Acquisition. In addition we recorded a tax benefit of $21 million for discreet items, including a state law change in Connecticut and the application of our effective state tax rates for jurisdictions for which we do not record a valuation allowance. Please read Note 3—Acquisitions for further discussion of the release of the valuation allowance.

Note 16—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 17—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans in our Form 10-K.

Upon the close of the Duke Midwest Acquisition on April 2, 2015, we assumed certain benefit plan obligations and the associated plan assets were transferred to us. As a result, we increased our net liability by approximately $13 million. These benefit plan obligations and related plan assets were merged into our pension and other post-employment benefit plans. The Duke employees began participating in our plans upon acquisition, which as a result triggered a re-measurement of our plans. As a result of the re-measurements, we recorded a loss through accumulated other comprehensive income and increased our net liability by approximately $5 million during the second quarter of 2015.

No benefit plan obligations associated with the EquiPower employees were assumed upon the EquiPower Acquisition on April 1, 2015. The EquiPower employees will become eligible to participate in our plans effective January 1, 2016.

Components of Net Periodic Benefit Cost. The components of net periodic benefit cost (gain) were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
(amounts in millions)	2015	2014	2015	2014
Service cost benefits earned during period	$4	$3	$—	$—
Interest cost on projected benefit obligation	5	5	1	1
Expected return on plan assets	(6)	(6)	(1)	(1)
Amortization of prior service credit	(1)	(1)	—	—
Net periodic benefit cost	$2	$1	$—	$—

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
(amounts in millions)	2015	2014	2015	2014
Service cost benefits earned during period	$7	$6	$—	$—
Interest cost on projected benefit obligation	9	9	2	2
Expected return on plan assets	(11)	(11)	(2)	(2)
Amortization of prior service credit	(1)	(1)	(1)	(1)
Net periodic benefit cost (gain)	$4	$3	$(1)	$(1)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Note 17—Earnings (Loss) Per Share

The reconciliation of basic earnings (loss) per share to diluted earnings (loss) per share from continuing operations attributable to our common stockholders during the three and six months ended June 30, 2015 and 2014 is shown in the following table. Please read Note 16—Capital Stock in our Form 10-K for further discussion.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	2015	2014	2015	2014
Income (loss) from continuing operations	$386	$(122)	$205	$(159)
Less: Net income (loss) attributable to noncontrolling interest	(2)	1	(3)	5
Income (loss) from continuing operations attributable to Dynegy Inc.	388	(123)	208	(164)
Less: Dividends on preferred stock	6	—	11	—
Income (loss) from continuing operations attributable to Dynegy Inc. common stockholders for basic earnings (loss) per share	382	(123)	197	(164)
Add: Dividends on preferred stock	6	—	11	—
Adjusted income (loss) from continuing operations attributable to Dynegy Inc. common stockholders for diluted earnings (loss) per share	$388	$(123)	$208	$(164)
Basic weighted-average shares	128	100	126	100
Effect of dilutive securities (1)	14	—	14	—
Diluted weighted-average shares	142	100	140	100
Earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders:				
Basic	$2.98	$(1.23)	$1.56	$(1.64)
Diluted (1)	$2.73	$(1.23)	$1.49	$(1.64)

(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 the three and six months ended June 30, 2014.

For the three and six months ended June 30, 2015 and 2014, 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)	2015	2014
Stock options	—	1.4
Restricted stock units	—	1.1
Performance stock units	—	0.3
Warrants	15.6	15.6
Total	15.6	18.4

Note 18—Condensed Consolidating Financial Information

On May 20, 2013, Dynegy issued the Senior Notes, as further described in Note 13—Debt. On October 27, 2014, the Escrow Issuers, wholly-owned subsidiaries of Dynegy, issued the Notes as further described in Note 13—Debt. On the respective closing dates, Dynegy executed a second and third supplemental indenture adding the EquiPower Guarantors and the Duke Guarantors as guarantors of the $500 million in aggregate principal amount of the Senior Notes. The 100 percent owned subsidiary guarantors, jointly, severally, fully and unconditionally, guarantee the payment obligations under the Senior Notes and Notes. Not all of Dynegy's subsidiaries guarantee the Senior Notes and Notes including Dynegy’s indirect, wholly-owned subsidiary, IPH, which acquired AER and its subsidiaries on December 2, 2013.

The following condensed consolidating financial statements present the financial information of (i) Dynegy (Parent), which is the parent and issuer of the Senior Notes and Notes, on a stand-alone, unconsolidated basis, (ii) the guarantor subsidiaries

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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 financial statements and notes thereto of Dynegy. The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information 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, 2015 and December 31, 2014.

Condensed Consolidating Balance Sheet as of June 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$296	$237	$178	$—	$711
Accounts receivable, net	581	931	182	(1,255)	439
Inventory	—	312	211	—	523
Other current assets	27	332	76	(11)	424
Total Current Assets	904	1,812	647	(1,266)	2,097
Property, Plant and Equipment, Net	—	7,922	744	—	8,666
Other Assets					
Investment in affiliates	12,978	199	—	(12,978)	199
Goodwill	—	837	—	—	837
Other assets	111	192	53	(6)	350
Intercompany note receivable	7	—	—	(7)	—
Total Assets	$14,000	$10,962	$1,444	$(14,257)	$12,149
Current Liabilities					
Accounts payable	$909	$233	$464	$(1,255)	$351
Other current liabilities	144	296	166	(11)	595
Total Current Liabilities	1,053	529	630	(1,266)	946
Debt, long-term portion	6,374	—	705	—	7,079
Intercompany note payable	3,042	—	7	(3,049)	—
Other liabilities	209	387	215	(6)	805
Total Liabilities	10,678	916	1,557	(4,321)	8,830
Stockholders' Equity					
Dynegy Stockholders' Equity	3,322	13,088	(110)	(12,978)	3,322
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	3,322	10,046	(110)	(9,936)	3,322
Noncontrolling interest	—	—	(3)	—	(3)
Total Equity	3,322	10,046	(113)	(9,936)	3,319
Total Liabilities and Equity	$14,000	$10,962	$1,444	$(14,257)	$12,149

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Condensed Consolidating Balance Sheet as of December 31, 2014
(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets						
Cash and cash equivalents	$1,642	$—	$54	$174	$—	$1,870
Restricted cash	—	113	—	—	—	113
Accounts receivable, net	14	—	732	176	(652)	270
Inventory	—	—	82	126	—	208
Other current assets	9	6	125	73	—	213
Total Current Assets	1,665	119	993	549	(652)	2,674
Property, Plant and Equipment, Net	—	—	2,675	580	—	3,255
Other Assets						
Investment in affiliates	6,133	—	—	—	(6,133)	—
Restricted cash	—	5,100	—	—	—	5,100
Other assets	46	47	43	67	—	203
Intercompany note receivable	17	—	—	—	(17)	—
Total Assets	$7,861	$5,266	$3,711	$1,196	$(6,802)	$11,232
Current Liabilities						
Accounts payable	$310	$166	$111	$281	$(652)	$216
Other current liabilities	51	67	246	101	—	465
Total Current Liabilities	361	233	357	382	(652)	681
Debt, long-term portion	1,277	5,100	—	698	—	7,075
Intercompany note payable	3,042	—	—	17	(3,059)	—
Other liabilities	158	—	103	192	—	453
Total Liabilities	4,838	5,333	460	1,289	(3,711)	8,209
Stockholders' Equity						
Dynegy Stockholders' Equity	3,023	(67)	6,293	(93)	(6,133)	3,023
Intercompany note receivable	—	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	3,023	(67)	3,251	(93)	(3,091)	3,023
Noncontrolling interest	—	—	—	—	—	—
Total Equity	3,023	(67)	3,251	(93)	(3,091)	3,023
Total Liabilities and Equity	$7,861	$5,266	$3,711	$1,196	$(6,802)	$11,232

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Condensed Consolidating Statements of Operations for the Three Months Ended June 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$841	$258	$(109)	$990
Cost of sales, excluding depreciation expense	—	(438)	(167)	109	(496)
Gross margin	—	403	91	—	494
Operating and maintenance expense	—	(165)	(85)	—	(250)
Depreciation expense	—	(144)	(31)	—	(175)
Loss on sale of assets, net	—	(1)	—	—	(1)
General and administrative expense	(2)	(26)	(7)	—	(35)
Acquisition and integration costs	—	(23)	—	—	(23)
Operating income (loss)	(2)	44	(32)	—	10
Equity in losses from investments in affiliates	501	—	—	(501)	—
Earnings from unconsolidated investments	—	3	—	—	3
Interest expense	(114)	—	(18)	—	(132)
Other income and expense, net	3	1	—	—	4
Income (loss) before income taxes	388	48	(50)	(501)	(115)
Income tax benefit (expense)	—	518	(17)	—	501
Net income (loss)	388	566	(67)	(501)	386
Less: Net loss attributable to noncontrolling interest	—	—	(2)	—	(2)
Net income (loss) attributable to Dynegy Inc.	$388	$566	$(65)	$(501)	$388

Condensed Consolidating Statements of Operations for the Six Months Ended June 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$1,144	$587	$(109)	$1,622
Cost of sales, excluding depreciation expense	—	(609)	(373)	109	(873)
Gross margin	—	535	214	—	749
Operating and maintenance expense	—	(221)	(140)	—	(361)
Depreciation expense	—	(196)	(43)	—	(239)
Loss on sale of assets	—	(1)	—	—	(1)
General and administrative expense	(3)	(43)	(19)	—	(65)
Acquisition and integration costs	—	(113)	—	—	(113)
Operating income (loss)	(3)	(39)	12	—	(30)
Equity in losses from investments in affiliates	447	—	—	(447)	—

Earnings from unconsolidated investments	—	3	—	—	3
Interest expense	(234)	—	(34)	—	(268)
Other income and expense, net	(2)	1	—	—	(1)
Income (loss) before income taxes	208	(35)	(22)	(447)	(296)
Income tax benefit (expense)	—	518	(17)	—	501
Net income (loss)	208	483	(39)	(447)	205
Less: Net loss attributable to noncontrolling interest	—	—	(3)	—	(3)
Net income (loss) attributable to Dynegy Inc.	$208	$483	$(36)	$(447)	$208

35

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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	$—	$260	$261	$—	$521
Cost of sales, excluding depreciation expense	—	(169)	(196)	—	(365)
Gross margin	—	91	65	—	156
Operating and maintenance expense	—	(74)	(62)	—	(136)
Depreciation expense	—	(44)	(13)	—	(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)	(28)	(24)	—	(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)
Income (loss) before income taxes	(107)	(18)	(38)	38	(125)
Income tax benefit (expense)	(16)	—	19	—	3
Net income (loss)	(123)	(18)	(19)	38	(122)
Less: Net income attributable to noncontrolling interest	—	—	1	—	1
Net income (loss) attributable to Dynegy Inc.	$(123)	$(18)	$(20)	$38	$(123)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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	$—	$595	$688	$—	$1,283
Cost of sales, excluding depreciation expense	—	(393)	(524)	—	(917)
Gross margin	—	202	164	—	366
Operating and maintenance expense	—	(133)	(113)	—	(246)
Depreciation expense	—	(98)	(26)	—	(124)
Gain on sale of assets, net	—	14	—	—	14
General and administrative expense	(4)	(29)	(22)	—	(55)
Acquisition and integration costs	—	—	(8)	—	(8)
Operating loss	(4)	(44)	(5)	—	(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)
Income (loss) before income taxes	(170)	(34)	(33)	77	(160)
Income tax benefit (expense)	6	—	(5)	—	1
Net income (loss)	(164)	(34)	(38)	77	(159)
Less: Net income attributable to noncontrolling interest	—	—	5	—	5
Net income (loss) attributable to Dynegy Inc.	$(164)	$(34)	$(43)	$77	$(164)

37

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended June 30, 2015

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$388	$ 566	$ (67)	$ (501)	$ 386
Other comprehensive loss before reclassifications:					
Actuarial loss, net of tax of zero	(5)	—	—	—	(5)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit, net of tax of zero	(1)	—	—	—	(1)
Other comprehensive loss, net of tax	(6)	—	—	—	(6)
Comprehensive income (loss)	382	566	(67)	(501)	380
Less: Comprehensive loss attributable to noncontrolling interest	—	—	(2)	—	(2)
Total comprehensive income (loss) attributable to Dynegy Inc.	$382	$ 566	$ (65)	$ (501)	$ 382

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Six Months Ended June 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$208	$ 483	$ (39)	$ (447)	$ 205
Other comprehensive loss before reclassifications:					
Actuarial loss, net of tax of zero	(5)	—	—	—	(5)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(2)	—	—	—	(2)
Other comprehensive loss, net of tax	(7)	—	—	—	(7)
Comprehensive income (loss)	201	483	(39)	(447)	198
Less: Comprehensive loss attributable to noncontrolling interest	—	—	(3)	—	(3)
Total comprehensive income (loss) attributable to Dynegy Inc.	$201	$ 483	$ (36)	$ (447)	$ 201

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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 income (loss)	$(123)	$(18)	$ (19)	$ 38	$ (122)
Other comprehensive income (loss) before reclassifications:					
Actuarial loss, net of tax of zero	—	—	—	—	—
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(1)	—	—	—	(1)
Other comprehensive income (loss) from investment in affiliates	—	—	—	—	—
Other comprehensive income (loss), net of tax	(1)	—	—	—	(1)
Comprehensive income (loss)	(124)	(18)	(19)	38	(123)
Less: Comprehensive income (loss) attributable to noncontrolling interest	—	—	1	—	1
Total comprehensive income (loss) attributable to Dynegy Inc.	$(124)	$(18)	$ (20)	$ 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)	$(34)	$ (38)	$ 77	$ (159)
Other comprehensive income (loss) before reclassifications:					
Actuarial loss, net of tax of zero	—	—	(3)	—	(3)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit and actuarial gain, 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)	(34)	(41)	80	(164)
Less: Comprehensive income (loss) attributable to noncontrolling interest	(1)	—	4	1	4
Total comprehensive income (loss) attributable to Dynegy Inc.	$(168)	$(34)	$ (45)	$ 79	$ (168)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Condensed Consolidating Statements of Cash Flow for the Six Months Ended June 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$(140)	$ 355	$ (236)	$—	$ (21)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(73)	(29)	—	(102)
Acquisitions, net of cash acquired	(6,221)	15	114	—	(6,092)
Decrease in restricted cash	5,148	—	—	—	5,148
Net intercompany transfers	(68)	—	—	68	—
Other investing	—	(10)	—	—	(10)
Net cash provided by (used in) investing activities	(1,141)	(68)	85	68	(1,056)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	—	—	6	—	6
Repayments of borrowings	(4)	(23)	—	—	(27)
Financing costs from debt issuance	(31)	—	—	—	(31)
Financing costs from equity issuance	(6)	—	—	—	(6)
Dividends paid	(12)	—	—	—	(12)
Net intercompany transfers	—	(81)	149	(68)	—
Interest rate swap settlement payments	(8)	—	—	—	(8)
Other financing	(4)	—	—	—	(4)
Net cash provided by (used in) financing activities	(65)	(104)	155	(68)	(82)
Net increase (decrease) in cash and cash equivalents	(1,346)	183	4	—	(1,159)
Cash and cash equivalents, beginning of period	1,642	54	174	—	1,870
Cash and cash equivalents, end of period	$296	$ 237	$ 178	$—	$ 711

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	—	12	—	—	12
Repayments of borrowings	(4)	—	—	—	(4)
Financing costs from debt issuance	(1)	—	—	—	(1)
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

40

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Note 19—Segment Information

We report the results of our operations in three segments: (i) Coal, (ii) IPH and (iii) Gas. The Coal segment includes certain of our coal-fired power generation facilities and our Dynegy Energy Services retail business. The IPH segment includes Genco, and Illinois Power Resources Generating, LLC ("IPRG"), which also own, 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. The Gas segment includes substantially all of our 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, 2015 and 2014 is presented below:

Segment Data as of and for the Three Months Ended June 30, 2015

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$317	$186	$485	$2	$990
Intercompany revenues	(10)	(1)	13	(2)	—
Total revenues	$307	$185	$498	$—	$990
Depreciation expense	$(47)	$(8)	$(119)	$(1)	$(175)
General and administrative expense	—	—	—	(35)	(35)
Acquisition and integration costs	—	—	—	(23)	(23)
Operating income (loss)	$(5)	$(14)	$86	$(57)	$10
Earnings from unconsolidated investments	—	—	3	—	3
Interest expense				(132)	(132)
Other income and expense, net	—	—	—	4	4
Loss before income taxes					(115)
Income tax benefit				501	501
Net income					386
Less: Net loss attributable to noncontrolling interest					(2)
Net income attributable to Dynegy Inc.					$388
Identifiable assets (domestic)	$2,637	$992	$7,997	$523	$12,149
Capital expenditures	$(16)	$(18)	$(25)	$(3)	$(62)

41

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

Segment Data as of and for the Six Months Ended June 30, 2015

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$460	$405	$755	$2	$1,622
Intercompany revenues	(11)	(1)	14	(2)	—
Total revenues	$449	$404	$769	$—	$1,622
Depreciation expense	$(57)	$(16)	$(164)	$(2)	$(239)
General and administrative expense	—	—	—	(65)	(65)
Acquisition and integration costs	—	—	—	(113)	(113)
Operating income (loss)	$2	$8	$138	$(178)	$(30)
Earnings from unconsolidated investments	—	—	3	—	3
Interest expense				(268)	(268)
Other income and expense, net	—	—	—	(1)	(1)
Loss before income taxes					(296)
Income tax benefit				501	501
Net income					205
Less: Net loss attributable to noncontrolling interest					(3)
Net income attributable to Dynegy Inc.					$208
Identifiable assets (domestic)	$2,637	$992	$7,997	$523	$12,149
Capital expenditures	$(19)	$(29)	$(49)	$(5)	$(102)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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)	(42)
Other income and expense, net	—	—	—	(39)	(39)
Loss before income taxes					(125)
Income tax benefit				3	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)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2015 and 2014

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)	(72)
Other income and expense, net	—	—	—	(45)	(45)
Loss before income taxes					(160)
Income tax benefit				1	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)

Note 20—Subsequent Events

Dividends

On July 1, 2015, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.34 per share, or approximately $5 million in the aggregate. The dividend is for the dividend period beginning on May 1, 2015 and ending on July 31, 2015. Such dividends were paid on August 3, 2015 to stockholders of record as of July 15, 2015.

Share Repurchase Program

On August 3, 2015, our Board of Directors authorized a share repurchase program for up to $250 million, initiated in the third quarter of 2015, with targeted completion in 2016. The shares will be purchased in the open market or privately negotiated transactions from time to time at management's discretion at prevailing market prices.

DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended June 30, 2015 and 2014
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 unregulated 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").

On April 1, 2015, we completed the acquisition of EquiPower Resources Corp. and Brayton Point Holdings, LLC from Energy Capital Partners for an aggregate base purchase price of approximately $3.35 billion in cash plus $105 million in common stock of Dynegy (the "EquiPower Acquisition"), subject to certain adjustments. On April 2, 2015, we completed the acquisition of Duke Energy's commercial generation assets and retail business in the Midwest for a base purchase price of approximately $2.80 billion in cash (the "Duke Midwest Acquisition"), subject to certain adjustments. With these transactions, we now own approximately 26,000 MW of generating capacity in eight states and also provide retail electricity to 895,000 residential customers and 30,200 commercial, industrial and municipal customers in Illinois, Ohio and Pennsylvania.

On August 3, 2015, our Board of Directors authorized a share repurchase program for up to $250 million, initiated in the third quarter of 2015, with targeted completion in 2016. The shares will be purchased in the open market or privately negotiated transactions from time to time at management's discretion at prevailing market prices.

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, 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 our revolving and letter of credit ("LC") facilities.

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 Illinois Power Generating Company ("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.

In connection with the closings of the Acquisitions, we entered into amendments to the Credit Agreement which provide for incremental revolving credit facilities that expand the credit available to us by an aggregate of $950 million which will be used to support our collateral and liquidity requirements. The loans issued pursuant to these facilities bear interest, initially, at either (i) 2.75 percent per annum plus LIBOR with respect to any LIBOR Loan or (ii) 1.75 percent per annum plus the Base Rate with respect to any Base Rate Loan, with steps down based on a Senior

Secured Leverage Ratio.

Table of Contents

On March 27, 2015, IPM entered into a letter of credit facility with an issuing bank for up to $25 million. The facility, which is collateralized by receivables, has a two-year tenor and may be extended if agreed to by both parties for one additional year. Interest on the facility is LIBOR plus 500 basis points on issued letters of credit. At June 30, 2015, there was approximately $20 million outstanding under this letter of credit facility. Please read Note 13—Debt—Letter of Credit Facilities for further discussion.

Liquidity. The following table summarizes our liquidity position at June 30, 2015:

	June 30, 2015		
(amounts in millions)	Dynegy Inc.	IPH (1) (2)	Total
Revolving facilities and LC capacity (3)	$1,480	$25	$1,505
Less: Outstanding letters of credit	(525)	(20)	(545)
Revolving facilities and LC availability	955	5	960
Cash and cash equivalents	569	142	711
Total available liquidity (4)	$1,524	$147	$1,671

(1) Includes cash of $116 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.

(3) Includes: (i) $950 million of aggregate available capacity related to our incremental revolving credit facilities, $475 million of available capacity related to the five-year senior secured revolving credit facility and $55 million related to a letter of credit and (ii) $25 million related to the two-year secured letter of credit facility. Please read Note 13—Debt—Letter of Credit Facilities for further discussion.

(4) On December 2, 2013, Dynegy and Illinois Power Resources, LLC entered into an intercompany revolving promissory note of $25 million. At June 30, 2015, there was approximately $15 million outstanding on the note, which is not reflected in the table above.

The following table presents net cash from operating, investing and financing activities for the six months ended June 30, 2015 and 2014:

	Six Months Ended June 30,	
(amounts in millions)	2015	2014
Net cash provided by (used in) operating activities	$(21)	$163
Net cash used in investing activities	$(1,056)	$(55)
Net cash used in financing activities	$(82)	$(3)

Operating Activities

Historical Operating Cash Flows. Cash used in operations totaled $21 million for the six months ended June 30, 2015. During the period, our power generation business provided cash of $317 million primarily due to the operation of our power generation facilities and our retail operations. Corporate and other activities used cash of $332 million primarily due to interest payments on our various debt agreements of $247 million and payments for acquisition-related costs of $102 million, offset by $17 million related to the Ponderosa Pine Energy, LLC ("PPE") cash receipt. In addition, changes in working capital and other, including general and administrative expenses, used cash of approximately $6 million.

Cash 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.

46

Table of Contents

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, 2015 and December 31, 2014:

(amounts in millions)	June 30, 2015	December 31, 2014
Dynegy Inc.:		
Cash (1)	$167	$14
Letters of credit	525	178
Total Dynegy Inc.	692	192
IPH:		
Cash (1) (2)	9	32
Letters of credit (3)	22	10
Total IPH	31	42
Total	$723	$234

(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, 2015 and December 31, 2014, $105 million and $9 million of cash, respectively, posted as collateral were netted against Liabilities from risk management activities on our unaudited consolidated balance sheets.

(2) Includes cash of $5 million related to Genco at June 30, 2015 and December 31, 2014.

(3) Includes letters of credit of approximately $2 million and $10 million related to the $25 million cash-backed LC facility at IPM at June 30, 2015 and December 31, 2014, respectively.

In addition to cash and letters of credit posted as collateral, we have increased the number of counterparties that participate in our first priority lien program. 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.

Collateral postings increased from December 31, 2014 to June 30, 2015 primarily due to acquisition-related collateral requirements, increased MISO FTR postings and other changes in our commercial activity.

The fair value of our derivatives collateralized by first priority liens included liabilities of $184 million and $141 million at June 30, 2015 and December 31, 2014, 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 economic hedging instruments in the future could be limited due to the potential collateral requirements of such instruments.

Table of Contents

Investing Activities

Capital Expenditures. Our capital spending by reportable segment was as follows:

	Six Months Ended June 30,	
(amounts in millions)	2015	2014
Coal	$19	$11
IPH	29	31
Gas	49	25
Other	5	2
Total (1)	$102	$69

(1) Includes capitalized interest of $6 million and $10 million for the six months ended June 30, 2015 and 2014, respectively.

Other Investing Activities. During the six months ended June 30, 2015, we paid $6.092 billion in cash, net of cash acquired, in connection with the Acquisitions and paid $10 million for other investing activities. In addition, there was a $5.148 billion cash inflow related to the release of restricted cash as a result of closing the Acquisitions. Please read Note 11—Debt in our Form 10-K and Note 3—Acquisitions for further discussion.

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 22—Dispositions and Discontinued Operations in our Form 10-K for further discussion.

Financing Activities

Historical Cash Flow from Financing Activities. Cash used in financing activities totaled $82 million for the six months ended June 30, 2015 primarily due to (i) $37 million in financing costs related to our debt and equity issuances, (ii) $27 million in repayments associated with our inventory financing agreements and term loan, (iii) $12 million in dividend payments on our Mandatory Convertible Preferred Stock and (iv) $8 million in interest rate swap settlement payments. Please read Note 13—Debt for further discussion.

Cash 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 from a repurchase agreement related to emission credits. Please read Note 13—Debt for further discussion.

Future Cash Flow from Financing Activities. As a result of our issuance of $400 million of mandatory convertible preferred stock on October 14, 2014, we are obligated to pay dividends of $5.4 million quarterly on a cumulative basis when declared by our Board of Directors or upon conversion. We may pay declared dividends in cash or, subject to certain limitations, in shares of our common stock or by delivery of any combination of cash and shares of our common stock. Our future cash flows from financing activities will include principal payments on our debt instruments as they become due, as well as periodic payments to settle our interest rate swap agreements. In addition, our future cash flows from financing activities will be impacted by our share repurchase program. Please read Note 20—Subsequent Events for further discussion.

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. Please read Note 13—Debt in our Form 10-K for further discussion.

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 uses 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, as defined within the Credit Agreement, we may only apply a maximum of $150 million in cash to our outstanding secured debt.

Our revolver usage at June 30, 2015 was 33 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 were in compliance at June 30, 2015.

Genco Senior Notes. On December 2, 2013, in connection with the acquisition of AER, 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.

Based on June 30, 2015 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.

Please read Note 13—Debt for further discussion.

Dividends. We have paid no cash dividends on our common stock and have no current intention of doing so. Any future determinations to pay cash dividends will be at the discretion of our Board of Directors, subject to applicable limitations under Delaware law, and will be dependent upon our results of operations, financial condition, contractual restrictions and other factors deemed relevant by our Board of Directors.

On March 3, 2015, our Board of Directors declared a dividend on our Mandatory Convertible Preferred Stock of $1.34 per share, or approximately $5 million. An equivalent dividend was also declared on July 1, 2015. Such dividends were paid on May 1, 2015 and August 3, 2015, respectively.

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	Ba3	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, 2015 and 2014. 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, 2015 Compared to Three Months Ended June 30, 2014

The following table provides summary financial data regarding our consolidated results of operations for the three months ended June 30, 2015 and 2014, respectively:

	Three Months Ended June 30,		Favorable (Unfavorable)	Favorable (Unfavorable)
(amounts in millions)	2015	2014	$ Change	% Change
Revenues	$990	$521	$ 469	90 %
Cost of sales, excluding depreciation expense	(496)	(365)	(131)	(36)%
Gross margin	494	156	338	217 %
Operating and maintenance expense	(250)	(136)	(114)	(84)%
Depreciation expense	(175)	(57)	(118)	(207)%
Gain (loss) on sale of assets, net	(1)	14	(15)	(107)%
General and administrative expense	(35)	(29)	(6)	(21)%
Acquisition and integration costs	(23)	(2)	(21)	NM
Operating income (loss)	10	(54)	64	119 %
Earnings from unconsolidated investments	3	10	(7)	(70)%
Interest expense	(132)	(42)	(90)	(214)%
Other income and expense, net	4	(39)	43	110 %
Loss before income taxes	(115)	(125)	10	8 %
Income tax benefit	501	3	498	NM
Net income (loss)	386	(122)	508	NM
Less: Net income (loss) attributable to noncontrolling interest	(2)	1	(3)	NM
Net income (loss) attributable to Dynegy Inc.	$388	$(123)	$ 511	NM

The following tables provide summary financial data regarding our operating income (loss) by segment for the three months ended June 30, 2015 and 2014, respectively:

	Three Months Ended June 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$307	$185	$498	$—	$990
Cost of sales, excluding depreciation expense	(134)	(131)	(231)	—	(496)
Gross margin	173	54	267	—	494
Operating and maintenance expense	(131)	(60)	(61)	2	(250)
Depreciation expense	(47)	(8)	(119)	(1)	(175)
Loss on sale of assets, net	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(35)	(35)
Acquisition and integration costs (1)	—	—	—	(23)	(23)
Operating income (loss)	$(5)	$(14)	$86	$(57)	$10

51

Table of Contents

	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)

(1) Relates to costs associated with the AER acquisition, Duke Midwest Acquisition and EquiPower Acquisition. Please read Note 3—Acquisitions for further discussion.

Discussion of Consolidated Results of Operations

Revenues. Our newly acquired plants contributed to increased revenues, while mild temperatures and increased precipitation levels have lowered demand in our generation areas, resulting in lower volumes and prices realized by our legacy plants, compared to 2014. Revenues increased by $469 million from $521 million for the three months ended June 30, 2014 to $990 million for the three months ended June 30, 2015. Gas segment revenues increased by $292 million, driven by a $401 million from the newly acquired plants, offset by $72 million in losses on derivative instruments and $37 million from lower energy revenues and the expiration of the ConEd contract at Independence. Coal segment revenues increased by $171 million, driven by $184 million from the newly acquired plants and $55 million of gains on derivative instruments, offset by $68 million primarily due to lower energy revenues. IPH segment revenues increased by $6 million primarily due to higher revenues from gains on derivative instruments, partially offset by lower energy revenues.

Cost of Sales. Cost of sales increased by $131 million from $365 million for the three months ended June 30, 2014 to $496 million for the three months ended June 30, 2015. Gas segment cost of sales increased by $85 million, driven by $138 million from the newly acquired plants, offset by a $53 million reduction in natural gas prices. Coal segment cost of sales increased by $45 million, driven by $66 million from the newly acquired plants, offset by $21 million lower coal and freight costs as a result of lower generation volumes.

Operating and Maintenance Expense. Operating and maintenance expense increased by $114 million from $136 million for the three months ended June 30, 2014 to $250 million for the three months ended June 30, 2015, primarily due to the newly acquired plants.

Depreciation Expense. Depreciation expense increased by $118 million from $57 million for the three months ended June 30, 2014 to $175 million for the three months ended June 30, 2015, as a result of the newly acquired plants.

Gain (loss) on Sale of Assets. Gain (loss) on sale of assets decreased by $15 million primarily due to a $14 million gain from the sale of our 50 percent ownership interest in Black Mountain in 2014, not repeated in 2015.

General and Administrative Expense. General and administrative expense increased by $6 million from $29 million for the three months ended June 30, 2014 to $35 million for the three months ended June 30, 2015. This increase was primarily due to higher overhead associated with the Acquisitions.

Acquisition and Integration Costs. Acquisition and integration costs increased by $21 million from $2 million for the three months ended June 30, 2014 to $23 million for the three months ended June 30, 2015. Acquisition and integration costs for the three months ended June 30, 2015 consisted of $12 million in severance costs related to the EquiPower Acquisition and $11 million in acquisition advisory and consulting fees. Acquisition and integration costs for the three months ended June 30, 2014 were related to the acquisition of AER. Please read Note 3—Acquisitions for further discussion.

Earnings from Unconsolidated Investments. Earnings from unconsolidated investments decreased by $7 million from $10 million for the three months ended June 30, 2014 to $3 million for the three months ended June 30, 2015. The Company received $10 million in cash distributions from Black Mountain during the three months ended June 30, 2014 and recorded $3 million in earnings from our 50 percent Elwood investment during the three months ended June 30, 2015.

Interest Expense. Interest expense increased by $90 million from $42 million for the three months ended June 30, 2014 to $132 million for the three months ended June 30, 2015 primarily due to the issuance of debt in October 2014 to finance the Acquisitions. Please read Note 13—Debt for further discussion.

Other Income and Expense, net. Other income and expense, net increased by $43 million from expense of $39 million for the three months ended June 30, 2014 to income of $4 million for the three months ended June 30, 2015. The increase was primarily due to a $46 million decrease in the change in the fair value of our common stock warrants.

Income Tax Benefit. We reported an income tax benefit of $501 million and $3 million for the three months ended June 30, 2015 and 2014, respectively. We released $480 million of our valuation allowance as a result of increased net deferred tax liabilities related to the EquiPower Acquisition. In addition, we recorded an additional tax benefit of $21 million for discreet items including a state law change in Connecticut and the application of our effective state tax rates for jurisdictions for which we do not record a valuation allowance. Please read Note 3—Acquisitions for further discussion of the release of the valuation allowance.

As of June 30, 2015, we continued to maintain a valuation allowance against our net deferred tax assets in each jurisdiction as they arise as there was not sufficient evidence to overcome our historical cumulative losses to conclude that it is more-likely-than-not our net deferred tax assets can be realized in the future.

Discussion of Adjusted EBITDA

Non-GAAP Performance Measures. In analyzing and planning for our business, we supplement our use of the Generally Accepted Accounting Principles of the United States of America (“GAAP”) financial measures with non-GAAP financial measures, including earnings before interest, taxes, depreciation and amortization (“EBITDA”) and Adjusted EBITDA. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed with our GAAP results and the accompanying reconciliations to corresponding GAAP financial measures included in the tables below, may provide a more complete understanding of factors and trends affecting our business. These non-GAAP financial measures should not be relied upon to the exclusion of GAAP financial measures and are by definition an incomplete understanding of Dynegy and must be considered in conjunction with GAAP measures.

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

EBITDA and Adjusted EBITDA. We define EBITDA as earnings (loss) before interest expense, income tax expense (benefit) and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA adjusted to exclude (i) gains or losses on the sale of 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 acquisitions, (iv) income or expense on up-front premiums received or paid for financial options in periods other than the strike periods, (v) income or loss attributable to noncontrolling interest and (vi) earnings or losses from unconsolidated investments. Adjusted EBITDA also includes cash distributions received from our unconsolidated investments.

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 EBITDA or 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 EBITDA or Adjusted EBITDA when performance is discussed on a segment level is Operating income (loss).

Table of Contents

Adjusted EBITDA — Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2015:

	Three Months Ended June 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net income attributable to Dynegy Inc.					$388
Loss attributable to noncontrolling interest					(2)
Income tax benefit					(501)
Other items, net					(4)
Interest expense					132
Earnings from unconsolidated investments					(3)
Operating income (loss)	$(5)	$(14)	$86	$(57)	$10
Depreciation expense	47	8	119	1	175
Amortization expense	(10)	—	5	—	(5)
Earnings from unconsolidated investments	—	—	3	—	3
Other items, net	—	—	—	4	4
EBITDA	32	(6)	213	(52)	187
Acquisition and integration costs	—	—	—	23	23
Loss attributable to noncontrolling interest	—	2	—	—	2
Mark-to-market adjustments	(14)	6	(10)	—	(18)
Change in fair value of common stock warrants	—	—	—	(3)	(3)
Loss on sale of assets, net	—	—	1	—	1
Other	1	3	(2)	(1)	1
Adjusted EBITDA	$19	$5	$202	$(33)	$193

Table of Contents

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)
Other items, net					39
Interest expense					42
Earnings from unconsolidated investments					(10)
Operating loss	$(5)	$(17)	$(2)	$(30)	$(54)
Depreciation expense	11	10	35	1	57
Amortization expense	(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
Income attributable to noncontrolling interest	—	(1)	—	—	(1)
Mark-to-market adjustments	—	4	10	—	14
Change in fair value of common stock warrants	—	—	—	43	43
Gain on sale of assets, net	—	—	(14)	—	(14)
Other	4	(1)	1	(3)	1
Adjusted EBITDA	$8	$—	$58	$(28)	$38

Adjusted EBITDA increased by $155 million from $38 million for the three months ended June 30, 2014 to $193 million for the three months ended June 30, 2015. The increase was primarily due to the newly acquired plants and higher spark spreads at the Gas segment, partially offset by lower realized power prices on the unhedged power sales at the Coal segment and the expiration of the ConEd contract at Independence at the Gas segment. Please read Discussion of Segment Adjusted EBITDA for further information.

Table of Contents

Discussion of Segment Adjusted EBITDA — Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the three months ended June 30, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$255	$157	$ 98	62 %
Capacity	28	1	27	NM
Mark-to-market income, net	10	—	10	NM
Contract amortization	(12)	—	(12)	NM
Other (1)	26	(22)	48	218 %
Total operating revenues	307	136	171	126 %
Operating Costs				
Cost of sales	(156)	(91)	(65)	(71)%
Contract amortization	22	2	20	NM
Total operating costs	(134)	(89)	(45)	(51)%
Gross margin	173	47	126	NM
Operating and maintenance expense	(131)	(41)	(90)	(220)%
Depreciation expense	(47)	(11)	(36)	NM
Operating loss	(5)	(5)	—	NM
Depreciation expense	47	11	36	NM
Amortization expense	(10)	(2)	(8)	NM
EBITDA	32	4	28	NM
Mark-to-market adjustments	(14)	—	(14)	NM
Other	1	4	(3)	(75)%
Adjusted EBITDA	$19	$8	$ 11	138 %
Million Megawatt Hours Generated (5)	7.5	4.6	2.9	63 %
IMA for Coal-Fired Facilities (2)(5)	72 %	92 %		
Average Capacity Factor for Coal-Fired Facilities (3)(5)	50 %	71 %		
Average Quoted Market On-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$33.15	$45.31	$ (12.16)	(27)%
Commonwealth Edison (NI Hub)	$31.47	$46.02	$ (14.55)	(32)%
Mass Hub	$29.16	$46.89	$ (17.73)	(38)%
AD Hub	$37.75	$48.88	$ (11.13)	(23)%
Average Quoted Market Off-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$23.89	$30.36	$ (6.47)	(21)%
Commonwealth Edison (NI Hub)	$19.70	$28.34	$ (8.64)	(30)%
Mass Hub	$19.25	$33.81	$ (14.56)	(43)%
AD Hub	$25.76	$32.78	$ (7.02)	(21)%

Table of Contents

(1) For the three months ended June 30, 2015 and 2014, respectively, Other includes $26 million and ($23) million in financial settlements, $1 million and zero in natural gas sales, ($2) million and $1 million in ancillary services and $1 million and zero in other miscellaneous items.

(2) IMA 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. The 2015 calculation excludes our Brayton Point facility and CTs. In 2015, the IMA for our facilities within MISO and PJM (excluding CTs) was 76 percent and 70 percent, respectively.

(3) Reflects actual production as a percentage of available capacity. The 2015 calculation excludes our Brayton Point facility and CTs. In 2015, the average capacity factors for our facilities within MISO and PJM (excluding CTs) were 56 percent and 45 percent, respectively.

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

(5) Reflects the activity for the period in which the Acquisitions were included in our consolidated results.

Operating loss for the three months ended June 30, 2015 was $5 million compared to $5 million for the three months ended June 30, 2014. Adjusted EBITDA was $19 million during the three months ended June 30, 2015 compared to $8 million during the same period in 2014. The $11 million increase in Adjusted EBITDA was primarily due to the newly acquired plants, offset by lower realized power prices on the unhedged portion of the MISO fleet and lower generation volumes driven primarily by mild temperatures and increased precipitation levels.

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, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$176	$190	$ (14)	(7)%
Capacity	11	12	(1)	(8)%
Mark-to-market loss, net	(6)	(4)	(2)	(50)%
Contract amortization	(8)	(12)	4	33 %
Other (1)	12	(7)	19	NM
Total operating revenues	185	179	6	3 %
Operating Costs				
Cost of sales	(139)	(139)	—	— %
Contract amortization	8	9	(1)	(11)%
Total operating costs	(131)	(130)	(1)	(1)%
Gross margin	54	49	5	10 %
Operating and maintenance expense	(60)	(54)	(6)	(11)%
Depreciation expense	(8)	(10)	2	20 %
Acquisition and integration costs	—	(2)	2	100 %
Operating loss	(14)	(17)	3	18 %
Depreciation expense	8	10	(2)	(20)%
Amortization expense	—	3	(3)	(100)%
EBITDA	(6)	(4)	(2)	(50)%
Acquisition and integration costs	—	2	(2)	(100)%
(Income) loss attributable to noncontrolling interest	2	(1)	3	NM
Mark-to-market adjustments	6	4	2	50 %
Other	3	(1)	4	NM
Adjusted EBITDA	$5	$—	$ 5	NM
Million Megawatt Hours Generated	4.7	5.1	(0.4)	(8)%
IMA for IPH Facilities (2)	91 %	86 %		
Average Capacity Factor for IPH Facilities (3)	54 %	58 %		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$33.15	$45.31	$ (12.16)	(27)%
Off-Peak: Indiana (Indy Hub)	$23.89	$30.36	$ (6.47)	(21)%

(1) For the three months ended June 30, 2015 and 2014, respectively, Other includes $10 million and $1 million in financial settlements, $1 million and ($4) million in ancillary services and $1 million and ($4) million in other miscellaneous items.

(2) IMA 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, 2015 was $14 million compared to $17 million for the three months ended June 30, 2014. Adjusted EBITDA was $5 million during the three months ended June 30, 2015 compared to zero during

Table of Contents

the same period in 2014. The $5 million increase in Adjusted EBITDA resulted from higher capacity revenues and higher energy margin, partially offset by higher operations and maintenance expense.

Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the three months ended June 30, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$361	$155	$ 206	133 %
Capacity	101	61	40	66 %
Mark-to-market income (loss), net	29	(10)	39	NM
Contract amortization	(7)	(20)	13	65 %
Other (1)	14	20	(6)	(30)%
Total operating revenues	498	206	292	142 %
Operating Costs				
Cost of sales	(233)	(148)	(85)	(57)%
Contract amortization	2	2	—	— %
Total operating costs	(231)	(146)	(85)	(58)%
Gross margin	267	60	207	NM
Operating and maintenance expense	(61)	(41)	(20)	(49)%
Depreciation expense	(119)	(35)	(84)	(240)%
Gain (loss) on sale of assets, net	(1)	14	(15)	(107)%
Operating income (loss)	86	(2)	88	NM
Depreciation expense	119	35	84	240 %
Amortization expense	5	18	(13)	(72)%
Earnings from unconsolidated investments	3	10	(7)	(70)%
EBITDA	213	61	152	NM
Mark-to-market adjustments	(10)	10	(20)	(200)%
Gain (loss) on sale of assets, net	1	(14)	15	107 %
Other	(2)	1	(3)	NM
Adjusted EBITDA	$202	$58	$ 144	248 %
Million Megawatt Hours Generated (2) (7)	12.8	3.7	9.1	246 %
IMA for Combined Cycle Facilities (3) (7)	97 %	97 %		
Average Capacity Factor for Combined Cycle Facilities (4) (7):	61 %	39 %		
Average Market On-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$12.57	$13.47	$ (0.90)	(7)%
PJM West	$29.38	$25.39	$ 3.99	16 %
North of Path 15 (NP 15)	$14.99	$15.83	$ (0.84)	(5)%
New York—Zone A	$22.34	$19.02	$ 3.32	17 %
Mass Hub	$13.48	$17.28	$ (3.80)	(22)%
AD Hub	$27.53	$24.19	$ 3.34	14 %
Average Market Off-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$0.80	$(4.22)	$ 5.02	119 %
PJM West	$15.66	$7.97	$ 7.69	96 %

North of Path 15 (NP 15)	$7.79	$4.64	$ 3.15	68 %
New York—Zone A	$6.54	$4.44	$ 2.10	47 %
Mass Hub	$3.58	$4.20	$ (0.62)	(15)%
AD Hub	$15.55	$8.10	$ 7.45	92 %
Average natural gas price—Henry Hub ($/MMBtu) (6)	$2.72	$4.58	$ (1.86)	(41)%

59

Table of Contents

---

(1) For the three months ended June 30, 2015 and 2014, respectively, Other includes ($19) million and $1 million in financial settlements, $10 million and $9 million in natural gas sales, $8 million and $7 million in ancillary services, $4 million and $2 million in tolls and $11 million and $1 million in RMR, option premiums and other miscellaneous items.

(2) The three months ended June 30, 2014 includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility which was sold on June 27, 2014.

(3) IMA 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.

(7) Reflects the activity for the period in which the Acquisitions were included in our consolidated results.

Operating income for the three months ended June 30, 2015 was $86 million compared to an operating loss of $2 million for the three months ended June 30, 2014. Adjusted EBITDA totaled $202 million during the three months ended June 30, 2015 compared to $58 million during the same period in 2014. The $144 million increase in Adjusted EBITDA was primarily due to the newly acquired plants, higher spark spreads and run times at our PJM plants, and improved market capacity, partially offset by the expiration of the ConEd contract at Independence.

Consolidated Summary Financial Information — Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

The following table provides summary financial data regarding our consolidated results of operations for the six months ended June 30, 2015 and 2014, respectively:

(amounts in millions)	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues	$1,622	$1,283	$ 339	26 %
Cost of sales, excluding depreciation expense	(873)	(917)	44	5 %
Gross margin	749	366	383	105 %
Operating and maintenance expense	(361)	(246)	(115)	(47)%
Depreciation expense	(239)	(124)	(115)	(93)%
Gain (loss) on sale of assets, net	(1)	14	(15)	(107)%
General and administrative expense	(65)	(55)	(10)	(18)%
Acquisition and integration costs	(113)	(8)	(105)	NM
Operating loss	(30)	(53)	23	43 %
Earnings from unconsolidated investments	3	10	(7)	(70)%
Interest expense	(268)	(72)	(196)	NM
Other income and expense, net	(1)	(45)	44	98 %
Loss before income taxes	(296)	(160)	(136)	(85)%
Income tax benefit	501	1	500	NM
Net income	205	(159)	364	229 %
Less: Net income (loss) attributable to noncontrolling interest	(3)	5	(8)	(160)%
Net income (loss) attributable to Dynegy Inc.	$208	$(164)	$ 372	227 %

Table of Contents

The following tables provide summary financial data regarding our operating income (loss) by segment for the six months ended June 30, 2015 and 2014, respectively:

	Six Months Ended June 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$449	$404	$769	$—	$1,622
Cost of sales, excluding depreciation expense	(222)	(269)	(382)	—	(873)
Gross margin	227	135	387	—	749
Operating and maintenance expense	(168)	(111)	(84)	2	(361)
Depreciation expense	(57)	(16)	(164)	(2)	(239)
Loss on sale of assets, net	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(65)	(65)
Acquisition and integration costs (1)	—	—	—	(113)	(113)
Operating income (loss)	$2	$8	$138	$(178)	$(30)

	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)

(1) Relates to costs associated with the AER acquisition, Duke Midwest Acquisition and EquiPower Acquisition. Please read Note 3—Acquisitions for further discussion.

Discussion of Consolidated Results of Operations

Revenues. Our newly acquired plants contributed to increased revenues, while mild temperatures and increased precipitation levels have lowered demand in our generation areas, resulting in lower volumes and prices realized by our legacy plants, compared to 2014. Revenues increased by $339 million from $1,283 million for the six months ended June 30, 2014 to $1,622 million for the six months ended June 30, 2015. Gas segment revenues increased by $161 million, driven by $401 million from the newly acquired plants and a $22 million in losses on derivative instruments, offset by $262 million due to lower energy revenues and the expiration of the ConEd contract at Independence. Coal segment revenues increased by $157 million, driven by $184 million from the newly acquired plants and $128 million of gains on derivative instruments, offset by $155 million primarily due to lower energy revenues. IPH segment revenues increased by $21 million primarily due to higher revenues from gains on derivative instruments, partially offset by lower energy revenues.

Cost of Sales. Cost of sales decreased by $44 million from $917 million for the six months ended June 30, 2014 to $873 million for the six months ended June 30, 2015. Gas segment cost of sales decreased by $61 million, driven by a $199 million reduction in natural gas prices, offset by a $138 million increase from the newly acquired plants. Coal segment cost of sales increased by $37 million, driven by $66 million from the newly acquired plants, offset by $29 million lower coal and freight costs as a result of lower generation volumes. IPH segment cost of sales decreased by $20 million, driven by lower freight costs as a result of lower generation volumes.

Table of Contents

Operating and Maintenance Expense. Operating and maintenance expense increased by $115 million from $246 million for the six months ended June 30, 2014 to $361 million for the six months ended June 30, 2015, primarily due to the newly acquired plants.

Depreciation Expense. Depreciation expense increased by $115 million from $124 million for the six months ended June 30, 2014 to $239 million for the six months ended June 30, 2015, as a result of the newly acquired plants.

Gain (loss) on Sale of Assets. Gain (loss) on sale of assets decreased by $15 million primarily due to a $14 million gain from the sale of our 50 percent ownership interest in Black Mountain in 2014, not repeated in 2015.

General and Administrative Expense. General and administrative expense increased by $10 million from $55 million for the six months ended June 30, 2014 to $65 million for the six months ended June 30, 2015. This increase was primarily due to higher overhead associated with the Acquisitions.

Acquisition and Integration Costs. Acquisition and integration costs increased by $105 million from $8 million for the six months ended June 30, 2014 to $113 million for the six months ended June 30, 2015. Acquisition and integration costs for the six months ended June 30, 2015 consisted of $48 million in Bridge Loan financing fees, $12 million in severance costs related to the EquiPower Acquisition and $53 million in acquisition advisory and consulting fees. Acquisition and integration costs for the six months ended June 30, 2014 were related to the acquisition of AER. Please read Note 3—Acquisitions for further discussion.

Earnings from Unconsolidated Investments. Earnings from unconsolidated investments decreased by $7 million from $10 million for the six months ended June 30, 2014 to $3 million for the six months ended June 30, 2015. The Company received $10 million in cash distributions from Black Mountain during the six months ended June 30, 2014 and recorded $3 million in earnings from our 50 percent Elwood investment during the six months ended June 30, 2015.

Interest Expense. Interest expense increased by $196 million from $72 million for the six months ended June 30, 2014 to $268 million for the six months ended June 30, 2015 primarily due to the issuance of debt in October 2014 to finance the Acquisitions. Please read Note 13—Debt for further discussion.

Other Income and Expense, net. Other income and expense, net decreased by $44 million from expense of $45 million for the six months ended June 30, 2014 to expense of $1 million for the six months ended June 30, 2015. This was primarily due to a $47 million decrease in the change in fair value of our common stock warrants.

Income Tax Benefit. We reported an income tax benefit of $501 million and $1 million for the six months ended June 30, 2015 and 2014, respectively. We released $480 million of our valuation allowance as a result of increased net deferred tax liabilities related to the EquiPower Acquisition. In addition, we recorded an additional tax benefit of $21 million for discreet items including a state law change in Connecticut and the application of our effective state tax rates for jurisdictions for which we do not record a valuation allowance. Please read Note 3—Acquisitions for further discussion of the release of the valuation allowance.

As of June 30, 2015, we continued to maintain a valuation allowance against our net deferred tax assets in each jurisdiction as they arise as there was not sufficient evidence to overcome our historical cumulative losses to conclude that it is more-likely-than-not our net deferred tax assets can be realized in the future.

Table of Contents

Adjusted EBITDA — Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2015:

	Six Months Ended June 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net income attributable to Dynegy Inc.					$208
Loss attributable to noncontrolling interest					(3)
Income tax benefit					(501)
Other items, net					1
Interest expense					268
Earnings from unconsolidated investments					(3)
Operating income (loss)	$2	$8	$138	$(178)	$(30)
Depreciation expense	57	16	164	2	239
Amortization expense	(11)	(1)	3	—	(9)
Earnings from unconsolidated investments	—	—	3	—	3
Other items, net	—	—	—	(1)	(1)
EBITDA	48	23	308	(177)	202
Acquisition and integration costs	—	—	—	113	113
Loss attributable to noncontrolling interest	—	3	—	—	3
Mark-to-market adjustments	(21)	(5)	(23)	—	(49)
Change in fair value of common stock warrants	—	—	—	2	2
Loss on sale of assets, net	—	—	1	—	1
Other	2	6	(2)	—	6
Adjusted EBITDA	$29	$27	$284	$(62)	$278

Table of Contents

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)
Other items, net					45
Interest expense					72
Earnings from unconsolidated investments					(10)
Operating income (loss)	$4	$(33)	$32	$(56)	$(53)
Depreciation expense	25	18	79	2	124
Amortization expense	(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
Income attributable to noncontrolling interest	—	(5)	—	—	(5)
Mark-to-market adjustments	19	38	18	—	75
Change in fair value of common stock warrants	—	—	—	49	49
Gain on sale of assets, net	—	—	(14)	—	(14)
Other	5	2	1	(2)	6
Adjusted EBITDA	$50	$30	$162	$(52)	$190

Adjusted EBITDA increased by $88 million from $190 million for the six months ended June 30, 2014 to $278 million for the six months ended June 30, 2015. The increase was primarily due to the newly acquired plants and higher spark spreads at the Gas segment, partially offset by lower realized power prices on the unhedged power sales at the Coal segment and the expiration of the ConEd contract at Independence at the Gas segment. Please read Discussion of Segment Adjusted EBITDA for further information.

Table of Contents

Discussion of Segment Adjusted EBITDA — Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the six months ended June 30, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$386	$375	$ 11	3 %
Capacity	30	3	27	NM
Mark-to-market income (loss), net	17	(19)	36	189 %
Contract amortization	(12)	—	(12)	NM
Other (1)	28	(67)	95	142 %
Total operating revenues	449	292	157	54 %
Operating Costs				
Cost of sales	(245)	(188)	(57)	(30)%
Contract amortization	23	3	20	NM
Total operating costs	(222)	(185)	(37)	(20)%
Gross margin	227	107	120	112 %
Operating and maintenance expense	(168)	(78)	(90)	(115)%
Depreciation expense	(57)	(25)	(32)	(128)%
Operating income	2	4	(2)	(50)%
Depreciation expense	57	25	32	128 %
Amortization expense	(11)	(3)	(8)	NM
EBITDA	48	26	22	85 %
Mark-to-market adjustments	(21)	19	(40)	(211)%
Other	2	5	(3)	(60)%
Adjusted EBITDA	$29	$50	$ (21)	(42)%
Million Megawatt Hours Generated (5)	12.3	9.9	2.4	24 %
IMA for Coal-Fired Facilities (2)(5)	79 %	90 %		
Average Capacity Factor for Coal-Fired Facilities (3)(5)	57 %	76 %		
Average Quoted Market On-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$36.21	$58.34	$ (22.13)	(38)%
Commonwealth Edison (NI Hub)	$36.15	$63.63	$ (27.48)	(43)%
Mass Hub	$62.67	$108.75	$ (46.08)	(42)%
AD Hub	$41.86	$69.42	$ (27.56)	(40)%
Average Quoted Market Off-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$26.43	$36.73	$ (10.30)	(28)%
Commonwealth Edison (NI Hub)	$23.78	$35.64	$ (11.86)	(33)%
Mass Hub	$47.84	$78.37	$ (30.53)	(39)%
AD Hub	$28.69	$40.62	$ (11.93)	(29)%

Table of Contents

(1) For the six months ended June 30, 2015 and 2014, respectively, Other includes $28 million and ($69) million in financial settlements, $1 million and zero in natural gas sales, ($2) million and $2 million in ancillary services and $1 million and zero in other miscellaneous items.

(2) IMA 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. The 2015 calculation excludes our Brayton Point facility and CTs. In 2015, the IMA for our facilities within MISO and PJM (excluding CTs) was 86 percent and 70 percent, respectively.

(3) Reflects actual production as a percentage of available capacity. The 2015 calculation excludes our Brayton Point facility and CTs. In 2015, the average capacity factors for our facilities within MISO and PJM (excluding CTs) were 65 percent and 45 percent, respectively.

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

(5) Reflects the activity for the period in which the Acquisitions were included in our consolidated results.

Operating income for the six months ended June 30, 2015 was $2 million compared to $4 million for the six months ended June 30, 2014. Adjusted EBITDA was $29 million during the six months ended June 30, 2015 compared to $50 million during the same period in 2014. The $21 million decrease in Adjusted EBITDA was primarily due to lower realized power prices on the unhedged portion of the MISO fleet and lower generation volumes driven primarily by mild temperatures and increased precipitation levels, offset by a positive impact related to the newly acquired plants.

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, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$370	$403	$ (33)	(8)%
Capacity	23	18	5	28 %
Mark-to-market income (loss), net	5	(38)	43	113 %
Contract amortization	(14)	(21)	7	33 %
Other (1)	20	21	(1)	(5)%
Total operating revenues	404	383	21	5 %
Operating Costs				
Cost of sales	(284)	(308)	24	8 %
Contract amortization	15	19	(4)	(21)%
Total operating costs	(269)	(289)	20	7 %
Gross margin	135	94	41	44 %
Operating and maintenance expense	(111)	(101)	(10)	(10)%
Depreciation expense	(16)	(18)	2	11 %
Acquisition and integration costs	—	(8)	8	100 %
Operating income (loss)	8	(33)	41	124 %
Depreciation expense	16	18	(2)	(11)%
Amortization expense	(1)	2	(3)	(150)%
EBITDA	23	(13)	36	NM
Acquisition and integration costs	—	8	(8)	(100)%
(Income) loss attributable to noncontrolling interest	3	(5)	8	160 %
Mark-to-market adjustments	(5)	38	(43)	(113)%
Other	6	2	4	200 %
Adjusted EBITDA	$27	$30	$ (3)	(10)%
Million Megawatt Hours Generated	9.9	11.4	(1.5)	(13)%
IMA for IPH Facilities (2)	92 %	89 %		
Average Capacity Factor for IPH Facilities (3)	56 %	65 %		
Average Quoted Market Power Prices ($/MWh) (4):	—			
On-Peak: Indiana (Indy Hub)	$36.21	$58.34	$ (22.13)	(38)%
Off-Peak: Indiana (Indy Hub)	$26.43	$36.73	$ (10.30)	(28)%

(1) For the six months ended June 30, 2015 and 2014, respectively, Other includes $16 million and $27 million in financial settlements, $1 million and ($5) million in ancillary services and $3 million and ($1) million in other miscellaneous items.

(2) IMA 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.

67

Table of Contents

Operating income for the six months ended June 30, 2015 was $8 million compared to an operating loss of $33 million for the six months ended June 30, 2014. Adjusted EBITDA was $27 million during the six months ended June 30, 2015 compared to $30 million during the same period in 2014. The $3 million decrease in Adjusted EBITDA resulted from lower generation volumes and lower power prices on the unhedged portion of the fleet. These decreases were partially offset by higher revenues from the segment’s cost-based contracts and higher capacity revenues.

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, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$589	$571	$ 18	3 %
Capacity	134	113	21	19 %
Mark-to-market income (loss), net	42	(18)	60	NM
Contract amortization	(7)	(40)	33	83 %
Other (1)	11	(18)	29	161 %
Total operating revenues	769	608	161	26 %
Operating Costs				
Cost of sales	(386)	(447)	61	14 %
Contract amortization	4	4	—	— %
Total operating costs	(382)	(443)	61	14 %
Gross margin	387	165	222	135 %
Operating and maintenance expense	(84)	(68)	(16)	(24)%
Depreciation expense	(164)	(79)	(85)	(108)%
Gain (loss) on sale of assets, net	(1)	14	(15)	(107)%
Operating income	138	32	106	NM
Depreciation expense	164	79	85	108 %
Amortization expense	3	36	(33)	(92)%
Earnings from unconsolidated investments	3	10	(7)	(70)%
EBITDA	308	157	151	96 %
Mark-to-market adjustments	(23)	18	(41)	(228)%
Gain (loss) on sale of assets, net	1	(14)	15	107 %
Other	(2)	1	(3)	NM
Adjusted EBITDA	$284	$162	$ 122	75 %
Million Megawatt Hours Generated (2)(7)	17.8	8.2	9.6	117 %
IMA for Combined Cycle Facilities (3)(7)	98 %	99 %		
Average Capacity Factor for Combined Cycle Facilities (4)(7)	61 %	44 %		
Average Market On-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$15.13	$13.26	$ 1.87	14 %
PJM West	$23.46	$28.85	$ (5.39)	(19)%
North of Path 15 (NP 15)	$13.82	$16.15	$ (2.33)	(14)%
New York—Zone A	$31.07	$46.49	$ (15.42)	(33)%
Mass Hub	$14.21	$22.87	$ (8.66)	(38)%
AD Hub	$29.68	$40.02	$ (10.34)	(26)%
Average Market Off-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$2.75	$(14.73)	$ 17.48	119 %
PJM West	$8.32	$(2.21)	$ 10.53	NM
North of Path 15 (NP 15)	$7.51	$6.34	$ 1.17	18 %
New York—Zone A	$15.93	$19.17	$ (3.24)	(17)%

Mass Hub	$(0.62)	$(7.50)	$ 6.88	92	%
AD Hub	$16.52	$11.22	$ 5.30	47	%
Average natural gas price—Henry Hub ($/MMBtu) (6)	$2.80	$4.83	$ (2.03)	(42	)%

69

Table of Contents

(1) For the six months ended June 30, 2015 and 2014, respectively, Other includes ($39) million and ($92) million in financial settlements, $16 million and $46 million in natural gas sales, $18 million and $23 million in ancillary services, $5 million and $3 million in tolls and $11 million and $2 million in RMR, option premiums and other miscellaneous items.
(2) The six months ended June 30, 2014 includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility which was sold on June 27, 2014.
(3) IMA 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.
(7) Reflects the activity for the period in which the Acquisitions were included in our consolidated results.

Operating income for the six months ended June 30, 2015 was $138 million compared to $32 million for the six months ended June 30, 2014. Adjusted EBITDA totaled $284 million during the six months ended June 30, 2015 compared to $162 million during the same period in 2014. The $122 million increase in Adjusted EBITDA was primarily due to a positive impact related to the newly acquired plants, higher spark spreads and improved market capacity pricing, partially offset by the expiration of the ConEd contract at Independence.

Outlook

We expect that our future financial results will continue to be impacted by 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 the availability of our plants. 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 related to water, air and coal ash regulations. Our coal fleet, primarily, may experience added costs associated with greenhouse gases (“GHG”) and the handling and disposal of coal ash.

All references to hedging within this Form 10-Q relate to economic hedging activities as we do not elect hedge accounting.

Our Operating Segments

Coal. The Coal segment is comprised of 11 operating generation facilities located within MISO (3,008 MW), PJM (3,877 MW) and the ISO-NE (1,493 MW) regions, with a total generating capacity of 8,378 MW.

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. The Baldwin transformer upgrade has been completed. Associated re-conductoring work will be phased in over the next two years. 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 in Illinois. When basis differentials between MISO LMPs and trading hub prices exist, we mitigate the basis risk between these prices through participation in FTR markets and busbar swaps to the extent they are economically available.

As of July 21, 2015, our expected remaining generation volumes, excluding Brayton Point, are 60 percent hedged volumetrically for 2015 and approximately 37 percent hedged volumetrically for 2016. We plan to continue our hedging program over a one- to three-year period using various instruments, which may include the sale of natural gas swaps as a cross-commodity hedge for our power revenue. Dynegy’s portfolio beyond the prompt year is primarily open to benefit from possible future power market pricing improvements. We use our retail business, Dynegy Energy Services, to hedge a portion of the output from our PJM facilities.

As of July 21, 2015, excluding non-operated jointly-owned generating units, our expected coal requirements for 2015 are 97 percent contracted and 95 percent priced. Our forecasted coal requirements for 2016 are 66 percent contracted and 63 percent priced. We look to procure and price additional fuel opportunistically. Our coal transportation requirements are fully contracted for 2015 and 2016. In addition, we recently entered into a new long-term coal transportation agreement for our Kincaid

Table of Contents

facility. The contract, which begins in 2017, reflects a reduction from the 2016 rate. Our coal transportation requirements are approximately 77 percent contracted for 2017 to 2019.

The Coal segment cleared no volume in the MISO Planning Year 2014-2015 capacity auction and cleared 398 MW in the MISO Planning Year 2015-2016 capacity auction at $150 per MW-day.

In New England, for our Brayton Point facility, Coal cleared 1,484 MW in the Planning Year 2014-2015 capacity auction, 1,363 MW in the Planning Year 2015-2016 capacity auction and 1,303 MW in the Planning Year 2016-2017 capacity auction. In May 2017, the Brayton Point facility will be retired. In New England, almost all of our capacity sales are made through ISO-NE capacity auctions.

In PJM, Coal cleared 3,341 MW in the Planning Year 2014-2015 capacity auction, 3,331 MW in the Planning Year 2015-2016 capacity auction, 3,567 MW in the Planning Year 2016-2017 capacity auction and 3,372 MW in the Planning Year 2017-2018 capacity auction.

IPH. The IPH segment is comprised of five plants, totaling 4,278 MW, including the Joppa CTs discussed below. The Coffeen, Edwards, Duck Creek and Newton facilities are located in the MISO region. Joppa, which is in the Electric Energy, Inc. ("EEI") control area, is interconnected to MISO, Tennessee Valley Authority and Louisville Gas and Electric Company.

As of July 21, 2015, our IPH expected remaining generation volumes are approximately 69 percent hedged volumetrically for 2015 and approximately 43 percent hedged volumetrically for 2016. IPH will continue to use its 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 July 21, 2015, our expected coal requirements for IPH for 2015 are fully contracted and 96 percent priced. Our forecasted coal requirements for 2016 are 79 percent contracted and 58 percent priced. We look to procure and price additional fuel opportunistically. Our coal transportation requirements are fully contracted for 2015 and 2016. Our coal transportation requirements are approximately 72 percent contracted for 2017 to 2019.

In addition, we recently entered into new long-term coal transportation agreements for our Duck Creek and Joppa facilities. The rate for Duck Creek is a reduction from the 2014 rate and began in April of 2015. The new Joppa transportation contract will begin in 2018 and is also a reduction from the 2017 rate.

We have also secured one segment of the transmission path required to offer an additional 240 MW of capacity and energy into PJM for Planning Year 2017-2018 through Planning Year 2021-2022. In July 2014, we executed a long-term wholesale contract for up to 120 MW annually for energy and capacity beginning in 2018 in Illinois bringing long-term, annual origination sales from the IPH segment to more than 470 MW.

IPH realized capacity sales in the MISO Planning Year 2014-2015 capacity auction, clearing 1,995 MW, all of which are expected to cover retail load obligations. IPH cleared 1,864 MW in the MISO Planning Year 2015-2016 capacity auction, including 1,709 MW that are expected to cover retail load obligations. IPH only sold 155 MW that received the $150 per MW-day clearing price.

In PJM, IPH cleared no volume in the Planning Year 2014-2015 capacity auction, 301 MW in the Planning Year 2015-2016 capacity auction, 856 MW in the Planning Year 2016-2017 capacity auction and 847 MW in the Planning Year 2017-2018 capacity auction.

Midwest Electric Power, Inc. ("MEPI"), a wholly owned subsidiary of EEI, and Genco own simple cycle combustion turbines located at Joppa. MEPI owns two 35 MW units and Genco owns three 55 MW units (collectively the "Joppa CTs"). The Joppa CTs have been on maintenance outage since 2013. Three of the Joppa CTs were in service by the end of July 2015, and all maintenance work and testing necessary to bring the remaining two units back to operational status is expected to be completed in August 2015.

We recently reached agreement on new collective bargaining agreements with the three unions representing our IPH facilities. These agreements cover approximately 400 represented employees located in Illinois and expire between 2018 and 2020.

Gas. The Gas segment is comprised of 19 power generation facilities within PJM (7,081 MW), CAISO (2,694 MW), ISO-NE (2,440 MW) and NYISO (1,108 MW) regions, totaling 13,323 MW of electric generating capacity. Excluding volumes subject to tolling agreements, as of July 21, 2015, our Gas portfolio is 50 percent hedged volumetrically through 2015 and approximately 14 percent hedged volumetrically for 2016. As a result of the offsetting risks of our Gas and

Table of Contents

Coal segments, we are able to reduce the costs associated with hedging with third parties 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.
In PJM, Gas cleared 5,922 MW in the Planning Year 2014-2015 capacity auction, 5,996 MW in the Planning Year 2015-2016 capacity auction, 6,201 MW in the Planning Year 2016-2017 capacity auction and 6,415 MW in the Planning Year 2017-2018 capacity auction.
In New England, Gas cleared 1,890 MW in the Planning Year 2014-2015 capacity auction, 1,956 MW in the Planning Year 2015-2016 capacity auction, 1,893 MW in the Planning Year 2016-2017 capacity auction, 2,147 MW in the Planning Year 2017-2018 capacity auction and 2,148 MW in the Planning Year 2018-2019 capacity auction. In New England, almost all of our capacity sales are made through ISO-NE capacity auctions.
In New York, almost all of our Independence facility's summer capacity had been sold bilaterally prior to the most recent auction, covering the Summer 2015 planning period. As of July 21, 2015, 1,107 MW of capacity were sold for the Winter 2014-2015 planning period; 908 MW were sold for the Summer 2015 planning period; 621 MW were sold for the Winter 2015-2016 planning period; 697 MW were sold for the Summer 2016 planning period; and 161 MW were sold for the Winter 2016-2017 planning period.
In its 2015 Gas Transmission and Storage rate case, which will set gas transportation rates for 2015-2017, Pacific Gas & Electric Company's ("PG&E") proposed revenue requirements and allocation proposals which, if adopted, would result in a significant increase in the rates for electric generators served by the local transmission system, including Dynegy's Moss Landing Units 1 & 2. Historically, after PG&E's gas transportation rate structure was changed to unbundle the Backbone Transmission System ("BB") rates, PG&E gas transmission and storage rate case settlements have included a bill credit for Moss Landing Units 1 & 2 that effectively reduces the differential between rates for BB and local transmission system service, allowing the plant to compete against other power generators. However, according to PG&E's own estimates, the rate differential between BB and local transmission system rates PG&E proposes in its 2015 proceeding would result in Moss Landing Units 1 & 2 likely experiencing a decline in dispatch hours. Dynegy is actively participating in the hearing process before the CPUC and is advocating positions that would maintain the ability of Moss Landing Units 1 & 2 to compete in California electricity markets. A post-hearing briefing concluded in May of 2015, with a decision expected in late 2015.
Capacity Markets
MISO. We have approximately 7,286 MW of power generation in MISO. The capacity auction results for MISO Local Resource Zone 4, in which our assets are located, are as follows for each Planning Year:

	2013-2014	2014-2015	2015-2016
Price per MW-day	$1.05	$16.75	$150.00

Asset retirements and confirmed future capacity exports from MISO to PJM are expected to continue reducing reserve margins in MISO. MISO has reversed its view that the reserve margin will fall below the needed generation level, known as the Planning Reserve Margin, which is currently 14.2 percent. MISO has forecasted reserve margins of 16.1 percent for Planning Year 2016-2017, 16.6 percent for Planning Year 2017-2018, 16.0 percent for Planning Year 2018-2019, 15.2 percent for Planning Year 2019-2020 and 14.7 percent for Planning Year 2020-2021.
In May of 2015, three complaints were filed at FERC regarding the Zone 4 results for the 2015-2016 PRA conducted by MISO. Dynegy is a named party in one of the complaints. The complainants, Public Citizen, Inc., the Illinois Attorney General, and Southwestern Electric Cooperative, Inc., have challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds and requested changes to the MISO PRA structure going forward. Complainants have also alleged that Dynegy may have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the 2015-2016 PRA. The MISO IMM, which was responsible for monitoring the MISO 2015-2016 PRA, determined that all offers were competitive and that no physical or economic withholding occurred. The MISO IMM also stated, in a filing responding to the complaints, that there is no basis for the proposed remedies. Dynegy complied fully with the terms of the MISO Tariff in connection with the 2015-2016 PRA. In addition, the Illinois Industrial Energy Consumers filed a complaint at FERC against MISO on June 30, 2015 requesting prospective changes to the MISO tariff. Please read Note 14—Commitments and Contingencies—Other

Contingencies—MISO 2015-2016 Planning Resource Auction Complaints for further information.

Table of Contents

ISO-NE. We have approximately 3,933 MW of power generation in ISO-NE. The most recent capacity auction results for ISO-NE Rest-of-Pool, in which most of our assets are located, are as follows for each Planning Year:

	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
Price per kW-month	$2.95	$3.21	$3.43	$3.15	$7.03	$9.55

The forecasted 2015 ISO-NE reserve margin is 22.8 percent versus a target reserve margin of 13.9 percent. On February 2, 2015, ISO-NE conducted the capacity auction for Planning Year 2018-2019 (FCA-9). Rest-of-Pool, which includes most of our facilities, cleared at a price of $9.55 per kW-month. The SEMA/RI zone, where our recently acquired Dighton facility is located, had insufficient supply to satisfy its capacity requirements. As a result, the zone separated from Rest-of-Pool, with existing resources in the zone receiving the Net Cost of New Entry ("Net CONE") price of $11.08 per kW-month and new resources in the zone receiving the auction starting price of $17.73 per kW-month. In the most recent auction, a downward sloping demand curve replaced the vertical demand curve and the system-wide administrative pricing rules. Performance incentive rules went into effect for Planning Year 2018-2019, having the potential to increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level.

PJM. We have approximately 10,958 MW of power generation in PJM. All gas-fired plants within PJM are in the RTO zone except for Liberty and Ontelaunee, which are in the MAAC zone. The most recent RPM auction results for PJM's RTO and MAAC zones, in which our assets are located, are as follows for each Planning Year:

	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
RTO zone, price per MW-day	$27.73	$125.99	$136.00	$59.37	$120.00
MAAC zone, price per MW-day	$226.15	$136.50	$167.46	$119.13	$120.00

PJM recently filed for FERC approval of changes to their capacity market with a product called Capacity Performance ("CP"). CP was developed by PJM in response to concerns about plant performance and system reliability. CP features increased availability and flexibility requirements, incentives for performance, significant penalties for non-performance and the ability to bid in a risk premium and recover costs previously disallowed by PJM and the independent market monitor.

On March 31, 2015, FERC issued a deficiency letter to PJM requesting additional information regarding certain elements of Capacity Performance. PJM answered the deficiency letter on April 10, 2015. On April 24, 2015, FERC granted PJM's request to delay the Planning Year 2018-2019 Base Residual Auction by up to 75 days (but no later than August 10, 2015) to give FERC time to rule on CP.

On June 9, 2015, FERC conditionally approved PJM's proposed CP product. Transitional CP Auctions will be held to procure 60 percent CP for the Planning Year 2016-2017 and 70 percent CP for the Planning Year 2017-2018. On July 22, 2015, FERC directed PJM to include CP-eligible demand response and energy efficiency products into the transitional auctions, which will result in a delay of their start from the originally scheduled dates. The Base Residual Auction for the Planning Year 2018-2019 will be held August 10 - 14, 2015.

NYISO. We have approximately 1,108 MW of power generation in NYISO. The forecasted 2015 NYISO reserve margin is 22.4 percent versus a target reserve margin of 17 percent. The most recent auction results for NYISO's Rest-of-State zones, in which the capacity for our Independence plant clears, are as follows for each planning period:

	Winter 2013-2014	Summer 2014	Winter 2014-2015	Summer 2015
Price per kW-month	$2.58	$5.15	$2.90	$3.50

CAISO. We have approximately 2,694 MW of power generation in CAISO. The CAISO capacity market is a bilateral market in which Load Serving Entities are required to procure sufficient resources to meet their peak load plus a 15 percent reserve margin. We transact with Investor Owned Utilities, Municipalities, Community Choice Aggregators, retail providers, and other marketers through RFO solicitations, broker markets, and directly with bilateral transactions. We transact both the standard resource adequacy ("RA") capacity as well as flexible RA capacity. Although the CPUC created the new flexible RA capacity market to address the risk of retirement of flexible gas fired generation, demand for this product is low due to ample supply of generation. In addition, growth for energy demand has been stagnant mainly due to energy efficiency programs and distributed generation of residential and commercial rooftop solar.

Table of Contents

Other Market Developments

On May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") vacated FERC Order No. 745, which provides compensation for demand response resources that participate in the energy markets administered by RTOs and ISOs. FERC requested a review of this decision on July 7, 2014, and the court denied the request on September 17, 2014. On October 20, 2014, the D.C. Circuit granted FERC's motion for a stay of the mandate, pending the deadline for filing of a petition for writ of certiorari with the U.S. Supreme Court. On January 15, 2015, two petitions were filed with the U.S. Supreme Court seeking review of the D.C. Circuit's decision in the case, one by FERC and one by private parties who intervened in the court of appeals in support of FERC. On May 4, 2015, the U.S. Supreme Court granted the petitions. Oral argument is expected in late 2015, with a decision likely by mid-2016. PJM has announced its intent to include demand response in its next base residual capacity auction, as modified by the PJM Capacity Performance Proposal accepted by FERC. Under PJM's plan, existing demand response resources that cannot meet Capacity Performance requirements (unlimited interruptions on an annual basis) will be allowed into the Base Capacity Product until Planning Year 2020-21, where they will be phased out, leaving only Capacity Performance demand response. Each of the other ISO/RTOs is evaluating options for complying with the decision, but it is unclear how Demand Response will participate in the energy, ancillary service and capacity markets, and therefore, it is too early to evaluate market impacts at this time.

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, 2015 for a detailed discussion of our environmental and regulatory matters.

The Clean Air Act

Mercury/HAPs. On June 29, 2015, the U.S. Supreme Court found that the EPA failed to properly consider costs when it promulgated the MATS rule. The Court remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings consistent with its opinion. The MATS rule remains in effect pending further action by the Court of Appeals.

We believe the Supreme Court's decision will have little or no bearing on the power markets, given that the majority of EGU retirement and investment decisions related to MATS have already been made or are in-progress. Furthermore, EGUs are or will be subject to a number of other environmental regulations that also affect retirement and investment decisions, such as the Coal Combustion Residuals ("CCR") rule and Cross-State Air Pollution Rule ("CSAPR"), and the anticipated Effluent Limitation Guidelines ("ELG") and Clean Power Plan.

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 capital investment. We have committed to retire Edwards Unit 1 as soon as the MISO allows us to retire the unit and, in accordance with our MISO tariff obligations, we requested and obtained from the Illinois EPA a one-year extension of the MATS compliance deadline for Edwards Unit 1. We also continue to monitor the performance of our other units and evaluate approaches to optimize compliance strategies.

Cross-State Air Pollution Rule ("CSAPR"). On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded without vacatur the CSAPR's 2014 SO_2 and ozone-season NOx emissions budgets for certain states to the EPA for reconsideration. As relevant to the states in which our EGUs are located, the court remanded the 2014 ozone-season NOx emissions budgets for Ohio, Pennsylvania and New York. The court found these budgets invalid because the data in the record showed that the downwind locations to which these upwind states were linked would comply with the NAAQS even with no obligation on the upwind states. The court rejected all other challenges to the CSAPR.

National Ambient Air Quality Standards ("NAAQS"). In May 2015, the EPA issued a final rule that eliminates existing exemptions in the state implementation plans ("SIPs") of many states, including Illinois and Ohio, for emissions during periods of startup, shutdown or malfunction ("SSM"). Affected states are required to submit corrective SIP revisions to the EPA by November 22, 2016. While the EPA has determined, for example, that automatic exemptions of excess emissions during SSM periods do not meet the Clean Air Act requirements, permissible SIPs may include alternative standards during SSM periods or include criteria and procedures for use of enforcement discretion by air agency personnel. Each state ultimately will have to decide how to address the specific SSM SIP inadequacies identified by the EPA.

The Clean Water Act

Cooling Water Intake Structures. At this time, based on our initial review of the EPA's final rule for cooling water intake structures at existing facilities, we estimate the capital cost of our compliance, including our newly acquired assets, will be approximately $62 million with the majority of spend in the 2020-2022 timeframe. This estimate excludes Moss Landing, which

Table of Contents

is discussed in Item 2. Results of Operations-Outlook-Environmental and Regulatory Matters in our Form 10-Q for the period ended March 31, 2015. Our estimate could change significantly depending upon a variety of factors, including site-specific determinations made by states in implementing the final rule, the results of assessments required by the rule, the results of site-specific engineering studies, and the outcome of litigation concerning the final rule.

Effluent Limitation Guidelines. In 2013, the EPA proposed revisions to the ELG for steam electric power generation units. The proposed rule would establish new or additional requirements for wastewater streams associated with steam electric power generation processes and byproducts, including flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and non-chemical metal cleaning. The proposed rule identifies four preferred options for regulation of discharges from existing sources, with the options differing in the number of waste streams covered, the size of the units controlled and the stringency of the controls to be imposed. The EPA is expected to take final action on the proposal in September 2015 and intends to align the ELG rule with its related CCR rule. We are currently evaluating the ELG proposal and CCR rule 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 regulations, which could be material. At this time, consistent with our previous estimates, our preliminary estimate is that the cost of our compliance, including our newly acquired assets, with the ELG rule will be approximately $288 million with the majority of spend in the 2018-2023 timeframe. This estimate assumes that the final ELG rule is within the EPA’s four stated preferred options, as proposed. This estimate could change significantly depending upon a variety of factors, including detailed site-specific engineering analyses, the final ELG rule, the outcome of potential litigation concerning the final rule, and our final compliance plans with the EPA’s CCR Rule.

Havana NPDES Permit. In September 2012, the Illinois EPA issued a renewed NPDES permit for our Coal segment’s Havana facility. Environmental interest groups filed a petition for review with the IPCB challenging the permit. The petitioners alleged 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 dismissed petitioners’ separate petition seeking to reopen and modify the NPDES permit to include mercury discharge limits. In June 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. The environmental interest groups appealed the IPCB’s decision. In July 2015, the Illinois Fourth District Appellate Court affirmed the IPCB’s decision, effectively upholding the permit subject to the IPCB’s remand of the permit to the Illinois EPA to require monthly monitoring of mercury.

Waters of the United States. In May 2015, the EPA and the U.S. Army Corps of Engineers released a final rule defining the term “waters of the United States,” which is used to determine the jurisdictional reach of the CWA. Our facilities may be affected by the final rule. The final rule identifies eight categories of waters that are regulated as “waters of the United States,” including waters that are subject to case-specific analysis to determine jurisdiction, and also identifies categories of waters that are excluded from jurisdiction. Several states, business groups and environmental organizations have filed lawsuits challenging the final rule.

Coal Combustion Residuals

EPA CCR Rule. We are currently evaluating the final CCR rule and the ELG proposal 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 regulations, which could be material. At this time, our preliminary view is that the CCR rule remains largely consistent with our previous expectations, and our estimate is that the cost of our compliance, including our newly acquired assets, with the CCR rule will be approximately $357 million with the majority of that spend in the 2019-2023 timeframe. This estimate includes the cost to close surface impoundments that are addressed in our AROs. This estimate could change significantly depending upon a variety of factors, including detailed site-specific engineering analyses, interpretative issues concerning the CCR rule’s requirements, decisions regarding options available under the CCR rule, the outcome of litigation concerning the rule, possible federal legislation concerning CCR regulation, state adoption of CCR rules, and the requirements of the EPA’s final ELG rule. In July 2015, several businesses, industry groups and environmental organizations filed petitions for judicial review of the CCR rule.

Illinois. In October 2013, the Illinois EPA filed a proposed rulemaking with the IPCB that would establish processes governing monitoring, corrective action and closure of CCR surface impoundments at power generating facilities. In May 2015 the IPCB granted the Illinois EPA's request for a 90-day stay of the rulemaking proceeding to consider the implications of the EPA final CCR rule. In August 2015, the Illinois EPA requested that the IPCB stay the rulemaking proceeding indefinitely to enable the Agency and interested parties to evaluate the impact of legal and legislative actions concerning the EPA final CCR rule.

Climate Change

Federal Regulation of Greenhouse Gases. On August 3, 2015, the EPA released as a final rule the Clean Power Plan to reduce carbon emissions from existing EGUs. The EPA also issued its final rules regarding carbon standards for new, modified

Table of Contents

and reconstructed EGUs, and a proposed federal plan and model rule to assist states in implementing the Clean Power Plan. The Clean Power Plan, when fully implemented in 2030, would reduce carbon dioxide ("CO_2") emissions from EGUs by 32 percent from 2005 levels. States would be required to develop plans to achieve interim CO_2 emission rates reductions phased in over the period 2022 to 2029 and the final CO_2 rate for their state by 2030. States must submit final plans by September 6, 2016, unless a state makes certain demonstrations justifying a two-year extension for submittal of a final plan by September 2018.

In June 2015, the U.S. Court of Appeals for the District of Columbia Circuit dismissed petitions challenging the EPA's proposed Clean Power Plan on the grounds that the rule was not yet final. Petitions for rehearing have been filed. Legal challenges to the final rule Clean Power Plan are expected.

We are analyzing the EPA's final rules to reduce EGU CO_2 emissions, the potential impacts on our power generation facilities, and how the rules intersect with electricity market design. The nature and scope of CO_2 emission reduction requirements that ultimately may be imposed on our facilities as a result of the EPA's EGU CO_2 reduction rules 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.

State Regulation of Greenhouse Gases. The Governor of California issued an executive order in April 2015 establishing a new statewide GHG reduction target of 40 percent below 1990 levels by 2030 to ensure California meets its 2050 GHG reduction target of 80 percent below 1990 levels.

The California Air Resources Board ("CARB") and the Province of Québec held their third joint allowance auction in May 2015 with current vintage auction allowances selling at a clearing price of $12.29 per metric ton and 2018 auction allowances selling at a clearing price of $12.10 per metric ton. The CARB expects allowance prices to be in the $15 to $30 range by 2020. We have participated in quarterly auctions or in secondary markets, as appropriate, to secure allowances for our affected assets. The next quarterly auction is scheduled for August 2015.

We estimate the cost of GHG allowances required to operate our units in California during 2015 will be approximately $15 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 which GHG allowance costs are passed through to the tolling counterparty, we expect only to acquire allowances covering the GHG emissions of Moss Landing Units 1 and 2.

In June 2015, RGGI held its twenty-eighth auction, in which approximately 15.5 million 2015 allowances were sold at a clearing price of $5.50 per allowance. RGGI's next quarterly auction is scheduled for September 2015. We have participated in 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 Connecticut, Maine, Massachusetts and New York during 2015 will be approximately $58 million. While the cost of allowances required to operate our RGGI-affected facilities is expected to increase 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, 2015	
Fair value of portfolio at December 31, 2014	$(83	)
Risk management gains recognized through the statement of operations in the period, net	32	
Contracts realized or otherwise settled during the period	34	
Acquisitions	(235	)
Changes in collateral/margin netting	96	
Fair value of portfolio at June 30, 2015	$(156	)

The net risk management liability of $156 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.

Table of Contents

Risk Management Asset and Liability Disclosures. The following table provides an assessment of net contract values by year as of June 30, 2015, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total	2015	2016	2017	2018	2019	Thereafter
Market quotations (1)(2)	$(193)	$(89)	$(86)	$(10)	$(5)	$(2)	$(1)
Prices based on models (2)	(68)	(11)	(2)	(44)	(12)	—	1
Total (3)	$(261)	$(100)	$(88)	$(54)	$(17)	$(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 5—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

(3) Excludes $105 million of broker margin that has been netted against Risk Management liabilities on our unaudited consolidated balance sheets. Please read Note 5—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 expect, believe or anticipate will or may occur in the future are forward-looking statements. These statements represent our reasonable judgment of the future based on various factors and using numerous assumptions and are subject to known and unknown risks, uncertainties and other factors that could cause our actual results and financial position to differ materially from those contemplated by the statements. You can identify these statements by the fact that they do not relate strictly to historical or current facts. They use words such as “anticipate,” “estimate,” “project,” “forecast,” “plan,” “may,” “will,” “should,” “expect” and other words of similar meaning. In particular, these include, but are not limited to, statements relating to the following:

- beliefs and assumptions about weather and general economic conditions;
- 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;
- beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale and retail power markets, including the anticipation of plant retirements and higher market pricing over the longer term;
- sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation thereof;
- the effects of, or changes to, MISO, PJM, CAISO, NYISO or ISO-NE power and capacity procurement processes;
- expectations regarding environmental matters, including costs of compliance, availability and adequacy of emission credits and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts and other laws and regulations to which we are, or could become, subject;
- beliefs about the outcome of legal, administrative, legislative and regulatory matters;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- our focus on safety and our ability to efficiently operate our assets so as to capture revenue generating opportunities and operating margins;
- our ability to mitigate forced outage risk as we become subject to proposed capacity performance in PJM and new performance incentives in ISO-NE;
- our ability to optimize our assets through targeted investment in cost effective technology enhancements;
- 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;
- ability to mitigate impacts associated with expiring RMR and/or capacity contracts;

- expectations regarding our compliance with the Credit Agreement, including collateral demands, interest expense, any applicable financial ratios and other payments;
- expectations regarding performance standards and capital and maintenance expenditures;
- the timing and anticipated benefits to be achieved through our company-wide improvement programs, including our PRIDE initiative;
- expectations regarding the synergies and anticipated benefits of the Acquisitions;
- beliefs concerning our capital allocation program, including the amount of shares, manner, timing and funding of the share repurchase program;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the South Bay and Vermilion facilities; and
- beliefs regarding redevelopment efforts for the Morro Bay facility.

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, except as noted below.

Goodwill

We record goodwill when the purchase price for an acquisition exceeds the estimated net fair value of the identified tangible and intangible assets acquired. We allocate goodwill to our reporting units based on the relative fair value of the purchased operating assets assigned to our existing reporting units.

We perform an annual impairment assessment in the fourth quarter of each year, or more frequently if indicators of potential impairment exist, to determine whether it is more likely than not that the fair value of a reporting unit in which goodwill resides is less than its carrying value.

For reporting units in which the impairment assessment concludes that it is more likely than not that the fair value is less than its carrying value, we perform the first step of the goodwill impairment test, which compares the fair value of the reporting unit to its carrying value inclusive of goodwill. If the fair value of the reporting unit exceeds the carrying value of the net assets assigned to that unit, goodwill is not considered impaired and we are not required to perform additional analysis. If the carrying value of the net assets assigned to the reporting unit exceeds the fair value of the reporting unit, then we must perform the second step of the goodwill impairment test to determine the implied fair value of the reporting unit’s goodwill. If we determine during the second step that the carrying value of a reporting unit’s goodwill exceeds its implied fair value, we record an impairment loss equal to the difference.

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, 2015.

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 and average VaR at June 30, 2015 compared to December 31, 2014 were lower due to a decrease in volatility and price.

Daily and Average VaR for Risk Management Portfolios

(amounts in millions)	June 30, 2015	December 31, 2014
One day VaR—95 percent confidence level	$8	$10
One day VaR—99 percent confidence level	$11	$14
Average VaR—95 percent confidence level for the rolling twelve months ended	$7	$8

Credit Risk. The following table represents our credit exposure at June 30, 2015 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	$16	$—	$16
Oil and gas producers	—	—	—
Utility and power generators	55	2	57
Total	$71	$2	$73

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, 2015 and December 31, 2014, respectively:

	June 30, 2015		December 31, 2014	
Interest rate swaps (in millions of U.S. dollars)	$781		$785	
Fixed interest rate paid (percent)	3.19	%	3.19	%

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 Chief Executive Officer ("CEO") and our Chief Financial Officer ("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, 2015.

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, 2015.

PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS

Please read Note 14—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
**4.1	Fourth Supplemental Indenture to the 2019 Notes Indenture, dated May 11, 2015, among Dynegy Inc., the Subsidiary Guarantors, (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor.
**4.2	Fourth Supplemental Indenture to the 2022 Notes Indenture, dated May 11, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor.
**4.3	Fourth Supplemental Indenture to the 2024 Notes Indenture, dated May 11, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association, as trustee, adding Dynegy Resource Holdings, LLC as a guarantor.
**4.4	Fourth Supplemental Indenture to the 2023 Notes Indenture, dated May 11, 2015, among Dynegy Inc., the Subsidiary Guarantors (as defined therein) and Wilmington Trust, National Association as Trustee, adding Dynegy Resource Holdings, LLC as a guarantor.
**10.1	Form of Stock Unit Award Agreement - Flexon (2015 Employment Agreement Award).
**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.

80

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, 2015	By:	/s/ CLINT C. FREELAND Clint C. Freeland Executive Vice President and Chief Financial Officer