DYNEGY INC.
Form 10-Q
November 05, 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 September 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, 120,553,913 shares outstanding as of October 19, 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
CT	Combustion Turbine
EGU	Electric Generating Units
EPA	Environmental Protection Agency
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
IMA	In-market Asset Availability
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
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
RMR	Reliability Must Run
S&P	Standard & Poor’s Ratings Services
SEC	U.S. Securities and Exchange Commission

Table of Contents

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

	September 30, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$934	$1,870
Restricted cash	—	113
Accounts receivable, net of allowance for doubtful accounts of $2 and $2, respectively	436	270
Inventory	531	208
Assets from risk management activities	69	78
Intangible assets	120	27
Prepayments and other current assets	177	108
Total Current Assets	2,267	2,674
Property, Plant and Equipment	9,269	3,685
Accumulated depreciation	(784)	(430)
Property, Plant and Equipment, Net	8,485	3,255
Other Assets		
Investment in unconsolidated affiliate	189	—
Restricted cash	—	5,100
Assets from risk management activities	48	2
Goodwill	818	—
Intangible assets	82	38
Deferred income taxes	54	20
Other long-term assets	214	143
Total Assets	$12,157	$11,232

See the notes to consolidated financial statements.

Table of Contents

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

	September 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$315	$216
Accrued interest	180	80
Deferred income taxes	67	20
Intangible liabilities	98	45
Accrued liabilities and other current liabilities	185	157
Liabilities from risk management activities	94	132
Debt, current portion	71	31
Total Current Liabilities	1,010	681
Debt, long-term portion	7,208	7,075
Other Liabilities		
Liabilities from risk management activities	135	31
Asset retirement obligations	326	205
Deferred income taxes	26	—
Intangible liabilities	73	36
Other long-term liabilities	198	181
Total Liabilities	8,976	8,209
Commitments and Contingencies (Note 14)		
Stockholders' Equity		
Preferred stock, $0.01 par value, 20,000,000 shares authorized:		
Series A 5.375% mandatory convertible preferred stock, $0.01 par value; 4,000,000 shares issued and outstanding, respectively	400	400
Common stock, $0.01 par value, 420,000,000 shares authorized; 128,179,226 shares issued and 123,182,927 shares outstanding at September 30, 2015; 124,436,941 shares issued and outstanding at December 31, 2014	1	1
Additional paid-in capital	3,309	3,338
Accumulated other comprehensive income, net of tax	24	20
Accumulated deficit	(552)	(736)
Total Dynegy Stockholders' Equity	3,182	3,023
Noncontrolling interest	(1)	—
Total Equity	3,181	3,023
Total Liabilities and Equity	$12,157	$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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues	$1,232	$615	$2,854	$1,898
Cost of sales, excluding depreciation expense	(621)	(387)	(1,494)	(1,304)
Gross margin	611	228	1,360	594
Operating and maintenance expense	(219)	(114)	(580)	(360)
Depreciation expense	(174)	(61)	(413)	(185)
Impairments and other charges	(74)	—	(74)	—
Gain (loss) on sale of assets, net	—	3	(1)	17
General and administrative expense	(29)	(25)	(94)	(80)
Acquisition and integration costs	(8)	(9)	(121)	(17)
Operating income (loss)	107	22	77	(31)
Earnings (losses) from unconsolidated investments	(4)	—	(1)	10
Interest expense	(145)	(32)	(413)	(104)
Other income and expense, net	46	5	45	(40)
Income (loss) before income taxes	4	(5)	(292)	(165)
Income tax benefit (expense) (Note 15)	(28)	—	473	1
Net income (loss)	(24)	(5)	181	(164)
Less: Net income (loss) attributable to noncontrolling interest	—	—	(3)	5
Net income (loss) attributable to Dynegy Inc.	(24)	(5)	184	(169)
Less: Dividends on preferred stock	5	—	16	—
Net income (loss) attributable to Dynegy Inc. common stockholders	$(29)	$(5)	$168	$(169)
Earnings (Loss) Per Share (Note 18):				
Basic earnings (loss) per share attributable to Dynegy Inc. common stockholders	$(0.23)	$(0.05)	$1.33	$(1.69)
Diluted earnings (loss) per share attributable to Dynegy Inc. common stockholders	$(0.23)	$(0.05)	$1.31	$(1.69)
Basic shares outstanding	126	100	126	100
Diluted shares outstanding	126	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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$(24)	$(5)	$181	$(164)
Other comprehensive income (loss) before reclassifications:				
Actuarial gain (loss) and plan amendments (net of tax of $2, zero, $2 and zero, respectively)	13	—	8	(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)	(3)	(3)
Other comprehensive income (loss), net of tax	12	(1)	5	(6)
Comprehensive income (loss)	(12)	(6)	186	(170)
Less: Comprehensive income (loss) attributable to noncontrolling interest	1	—	(2)	4
Total comprehensive income (loss) attributable to Dynegy Inc.	$(13)	$(6)	$188	$(174)

See the notes to consolidated financial statements.

4

Table of Contents

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

	Nine Months Ended September 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$181	$(164)
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Depreciation expense	413	185
Non-cash interest expense	25	15
Amortization of intangibles	(18)	38
Risk management activities	(117)	57
(Gain) loss on sale of assets, net	1	(17)
Loss from unconsolidated investments	1	—
Deferred income taxes	(473)	(1)
Impairment of long-lived assets	74	—
Change in value of common stock warrants	(43)	43
Other	37	27
Changes in working capital:		
Accounts receivable, net	(48)	187
Inventory	(52)	1
Prepayments and other current assets	95	32
Accounts payable and accrued liabilities	227	(124)
Distributions from unconsolidated investments	3	—
Changes in non-current assets	(23)	(9)
Changes in non-current liabilities	19	6
Net cash provided by operating activities	302	276
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(171)	(94)
Proceeds from asset sales, net	—	17
Acquisitions, net of cash acquired	(6,078)	—
Decrease in restricted cash	5,148	—
Distributions from unconsolidated affiliates	8	—
Other investing	(6)	—
Net cash used in investing activities	(1,099)	(77)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	88	12
Repayments of borrowings	(29)	(6)
Financing costs from debt issuance	(31)	(2)
Financing costs from equity issuance	(6)	—
Dividends paid	(17)	—
Interest rate swap settlement payments	(13)	(13)
Repurchase of common stock	(127)	—
Other financing	(4)	(1)
Net cash used in financing activities	(139)	(10)
Net increase (decrease) in cash and cash equivalents	(936)	189

Cash and cash equivalents, beginning of period	1,870	843
Cash and cash equivalents, end of period	$934	$1,032
Other non-cash investing and financing activity:		
Non-cash capital expenditures	$9	$36
Non-cash consideration transferred for Acquisitions	$105	$—
Non-cash capital expenditures pursuant to an equipment financing agreement	$63	$—

See the notes to consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 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 20—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 nine months ended September 30, 2015. Due to our Acquisitions in April 2015 and the authorization of a share repurchase program in August 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 September 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.

Treasury Stock. Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock, which is presented on our unaudited consolidated balance sheet as a reduction of Additional paid-in capital.

Accounting Standards Adopted During the Current Period

Business Combinations. In September 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-16-Business Combinations (Topic 805). The amendments in this ASU require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in this ASU require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments in this ASU require an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The guidance in this ASU is effective prospectively for interim and annual periods beginning after December 15, 2016, with early adoption permitted for financial statements that have not been issued. We adopted ASU 2015-16 as of September 30, 2015. Please see Note 3—Acquisitions for a summary of the impact on our unaudited consolidated financial statements.

Derivatives. In August 2015, the FASB issued ASU 2015-13-Derivatives and Hedging (Topic 815). The amendments in this ASU specify that the use of locational marginal pricing by an ISO does not constitute net settlement of a contract for the purchase or sale of electricity on a forward basis and, therefore, does not cause that contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. If the physical delivery criterion is met, along with all of the other criteria of the normal purchases and normal sales scope exception, an entity may elect to designate that contract as a normal purchase or normal sale. The amendments in this ASU are effective upon issuance and should be applied prospectively. The adoption of this ASU did not have a material impact on our unaudited consolidated financial statements.

Inventory. In July 2015, the FASB issued ASU 2015-11-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 adopted ASU 2015-11 as of July 1, 2015. The adoption of this ASU did not have a material impact on our unaudited consolidated financial statements.

Retirement Benefits. In April 2015, the FASB issued ASU 2015-04-Compensation-Retirement Benefits (Topic 715). For an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan or post retirement plan assets and obligations, the amendments in this ASU provide a practical expedient that permits the entity to remeasure the plan assets and obligations using the month-end that is closest to the date of the significant event. The month-end remeasurement of defined benefit plan assets and obligations that is closest to the date of the significant event should be adjusted for any effects of the significant event that may or may not be captured in the month-end measurement. An entity is required to disclose the accounting policy election and the date used to measure defined benefit plan assets and obligations in accordance with the amendments in this ASU. The amendments in this ASU are effective for public business entities for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years, with early adoption allowed. The amendments in this ASU should be applied prospectively. We adopted the guidance in this ASU on July 1, 2015.

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

Accounting Standards Not Yet Adopted

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.

In August 2015, the FASB issued ASU 2015-15-Interest-Imputation of Interest (Subtopic 835-30). The amendments in this ASU further clarify the guidance provided in ASU 2015-03 to include the presentation of debt issuance costs in relation to line-of-credit arrangements. The amendments state these costs may be presented as an asset and subsequently amortized ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement.

The guidance in these ASUs is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted. The adoption of these ASUs should be applied on a retrospective basis, affecting all balance sheet periods presented. We do not anticipate the adoption of these ASUs 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.

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). This ASU was further updated through the issuance of ASU 2015-14 in August 2015. 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 valuation of these assets and liabilities are classified as Level 3 within the fair value hierarchy levels. 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 recognized in the current period.

To fair value working capital, we used available market information. Asset retirement obligations were recorded in accordance with ASC 410. To fair value the acquired property, plant and equipment, we used a Discounted Cash Flow ("DCF") analysis, based upon a debt-free, free cash flow model. This DCF model was created for each power generation facility based on its estimated 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, based upon management's view of future conditions, 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 prices 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.

The following table summarizes the consideration paid and the provisional 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:

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

(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	47	124	171
Inventory	166	105	271
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	2,769	2,740	5,509
Investment in unconsolidated affiliate	201	—	201
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	3,625	3,189	6,814
Accounts payable	27	92	119
Accrued liabilities and other current liabilities	21	11	32
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	52	53	105
Intangible liabilities (including current portion of $24 million and $58 million, respectively)	73	93	166
Deferred income taxes, net	513	—	513
Other long-term liabilities	—	42	42
Total liabilities assumed	782	398	1,180
Identifiable net assets acquired	2,843	2,791	5,634
Goodwill	818	—	818
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 within our provisional valuation of the EquiPower Acquisition for the period ended June 30, 2015. As we had previously recorded a valuation allowance against our historical deferred tax assets, we released approximately $480 million of our valuation allowance as a result of these increased net deferred tax liabilities in the three months ended June 30, 2015. Due to the availability of new information related to the EquiPower Acquisition, we reduced the deferred tax liability in the three months ended September 30, 2015 by $24 million, offset by a corresponding reduction to goodwill. This reduction to the deferred tax liability resulted in a partial reversal of the previously recognized release of the valuation allowance by $21 million. The initial release of the valuation allowance and the partial reversal were recorded as Income tax benefit (expense) in our unaudited consolidated statements of operations for the three and nine months ended September 30, 2015.

The goodwill of $818 million resulting from the EquiPower Acquisition reflects the excess of our purchase price over the fair value of the net assets acquired. We allocated all of the goodwill to our Gas 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.

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

We incurred acquisition costs of $1 million and $86 million for the three and nine months ended September 30, 2015, respectively, related to the Acquisitions, which are included in Acquisition and integration costs in our unaudited consolidated statement of operations. Acquisition costs for the nine months ended September 30, 2015 include $48 million of commitment fees associated with a temporary bridge facility, which were payable only upon the closing of the Acquisitions. No amounts were borrowed under the bridge facility, and the bridge facility was cancelled, as our permanent financing for the Acquisitions was executed. Revenues of $589 million and $1,071 million and operating income of $91 million and $133 million attributable to the Acquisitions for the three and nine months ended September 30, 2015, respectively, are included in our unaudited consolidated statement of operations.

Pro Forma Results. The unaudited pro forma financial results for the nine months ended September 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.

	Nine Months Ended September 30,	
(amounts in millions)	2015	2014
Revenues	$3,844	$4,155
Net income (loss)	$442	$(555)
Net income (loss) attributable to noncontrolling interests	$(3)	$5
Net income (loss) attributable to Dynegy Inc.	$445	$(560)

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 1,576 MW natural gas-fired facility located in Elwood, Illinois. As of September 30, 2015, our equity method investment included in our unaudited consolidated balance sheet was $189 million. Upon the acquisition of our Elwood investment, we recognized basis differences in the net assets of approximately $90 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.

We recorded $4 million and $1 million in equity losses related to our investment in Elwood, which is reflected in Earnings (losses) from unconsolidated investments in our unaudited consolidated statement of operations for the three and nine months ended September 30, 2015. For the three months ended September 30, 2015, we received a distribution of $11 million, of which $8 million was considered a return of investment. As of September 30, 2015, we have approximately $4 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 $3 million and $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 nine months ended September 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 (losses) from unconsolidated investments in our unaudited consolidated statements of operations for the nine months ended September 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.

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

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

Many of our contractual arrangements are derivative instruments and are accounted for at fair value as part of Revenues in our unaudited consolidated statements of operations. We 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 September 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)	(46)	MWh	$(25)
Electricity basis derivatives (3)	(40)	MWh	$40
Natural gas derivatives (2)	313	MMBtu	$(133)
Natural gas basis derivatives	67	MMBtu	$(12)
Diesel fuel derivatives	4	Gallon	$(5)
Coal derivatives (4)	—	Metric Ton	$(30)
Heat rate derivatives	2	MWh/MMBtu	$(2)
Emissions derivatives	6	Metric Ton	$5
Interest rate swaps	779	U.S. Dollar	$(48)
Common stock warrants (5)	16	Warrant	$(18)

(1) Includes both asset and liability risk management positions, but excludes margin and collateral netting of $98 million.
(2) Mainly comprised of swaps, options and physical forwards.
(3) Comprised of FTRs and swaps.
(4) Our net position rounds to less than 1 million tons.
(5) Each warrant is convertible into one share of Dynegy common stock.

13

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

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 September 30, 2015 and December 31, 2014. As of September 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.

		September 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	$423	$(306)	$—	$117
Total derivative assets		$423	$(306)	$—	$117
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(585)	$306	$98	$(181)
Interest rate contracts	Liabilities from risk management activities	(48)	—	—	(48)
Common stock warrants	Other long-term liabilities	(18)	—	—	(18)
Total derivative liabilities		$(651)	$306	$98	$(247)
Total derivatives		$(228)	$—	$98	$(130)

		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 September 30, 2015 was $55 million, for which we have posted $10 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 September 30, 2015 and 2014

The following table summarizes our total cash collateral posted as of September 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	September 30, 2015	December 31, 2014
(amounts in millions)		
Gross collateral posted with counterparties	$148	$49
Less: Collateral netted against risk management liabilities	98	9
Net collateral within Prepayments and other current assets	$50	$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 nine months ended September 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 September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
(amounts in millions)					
Commodity contracts	Revenues	$48	$(3)	$120	$(212)
Interest rate contracts	Interest expense	$(9)	$1	$(17)	$(6)
Common stock warrants	Other income (expense), net	$45	$6	$43	$(43)

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, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 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 September 30, 2015 and 2014

	Fair Value as of September 30, 2015			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$257	$102	$359
Natural gas derivatives	—	43	5	48
Emissions derivatives	—	5	—	5
Coal derivatives	—	7	4	11
Total assets from commodity risk management activities	$—	$312	$111	$423
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(193)	$(151)	$(344)
Natural gas derivatives	—	(174)	(19)	(193)
Heat rate derivatives	—	—	(2)	(2)
Diesel fuel derivatives	—	(5)	—	(5)
Coal derivatives	—	(40)	(1)	(41)
Total liabilities from commodity risk management activities	—	(412)	(173)	(585)
Liabilities from interest rate contracts	—	(48)	—	(48)
Liabilities from outstanding common stock warrants	(18)	—	—	(18)
Total liabilities	$(18)	$(460)	$(173)	$(651)

	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)

16

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 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 September 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)	(5)	Million MWh	$(40)	Basis spread + liquid location	Basis spread	$7.00 - $9.00
FTRs	35	Million MWh	$(9)	Historical congestion	Forward price	$0.00 - $2.00
Heat rate derivatives:	—	Million MWh	$3	Option model	Gas/power price correlation	70% - 100%
	2	Million MMBtu	$(5)	Option model	Power price volatility	14% - 34%
Natural gas derivatives (1)	39	Million MMBtu	$(14)	Illiquid location fixed price	Forward price	$1.61 - $1.97
Coal derivatives (1)	(50)	Thousand Tons	$3	Illiquid location fixed price	Forward price	$5.80 - $7.10

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

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

	Three Months Ended September 30, 2015				
(amounts in millions)	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at June 30, 2015	$(54)	$(11)	$(7)	$4	$(68)
Total gains (losses) included in earnings	2	(3)	—	—	(1)

Settlements (1)	3	—	5	(1)	7
Balance at September 30, 2015	$(49)	$(14)	$(2)	$3	$(62)
Unrealized gains (losses) relating to instruments held as of September 30, 2015	$2	$(3)	$—	$—	$(1)

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

	Nine Months Ended September 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 gains included in earnings	7	—	—	—	7
Settlements (1)	2	—	7	(2)	7
Balance at September 30, 2015	$(49)	$(14)	$(2)	$3	$(62)
Unrealized gains relating to instruments held as of September 30, 2015	$7	$—	$—	$—	$7

	Three Months Ended September 30, 2014				
(amounts in millions)	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at June 30, 2014	$(14)	$—	$(1)	$—	$(15)
Total gains (losses) included in earnings	3	(1)	—	—	2
Settlements (1)	(2)	—	1	—	(1)
Balance at September 30, 2014	$(13)	$(1)	$—	$—	$(14)
Unrealized gains (losses) relating to instruments held as of September 30, 2014	$3	$(1)	$—	$—	$2

	Nine Months Ended September 30, 2014				
(amounts in millions)	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Coal Derivatives	Total
Balance at December 31, 2013	$11	$—	$(1)	$—	$10
Total losses included in earnings	(19)	(1)	—	—	(20)
Settlements (1)	(5)	—	1	—	(4)
Balance at September 30, 2014	$(13)	$(1)	$—	$—	$(14)
Unrealized losses relating to instruments held as of September 30, 2014	$(19)	$(1)	$—	$—	$(20)

(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 nine months ended September 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 nine months ended September 30, 2015 and 2014, other than the provisional purchase price allocation discussed in Note 3—Acquisitions.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 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 September 30, 2015 and December 31, 2014, respectively.

(amounts in millions)	September 30, 2015 Carrying Amount	September 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)	$(2,116)	$(2,100)	$(2,132)
Tranche B-2 Term Loan, due 2020 (1)(2)	$(779)	$(780)	$(785)	$(775)
7.375% Senior Notes, due 2022 (2)(6)	$(1,750)	$(1,768)	$(1,750)	$(1,777)
5.875% Senior Notes, due 2023 (2)	$(500)	$(469)	$(500)	$(475)
7.625% Senior Notes, due 2024 (2)(6)	$(1,250)	$(1,259)	$(1,250)	$(1,272)
Inventory financing agreements (2)	$(127)	$(127)	$(23)	$(23)
Equipment financing agreements (7)	$(63)	$(63)	$—	$—
Interest rate derivatives (2)	$(48)	$(48)	$(44)	$(44)
Commodity-based derivative contracts (3)	$(162)	$(162)	$(48)	$(48)
Common stock warrants (4)	$(18)	$(18)	$(61)	$(61)
Genco:				
7.00% Senior Notes Series H, due 2018 (2)(5)	$(274)	$(275)	$(268)	$(264)
6.30% Senior Notes Series I, due 2020 (2)(5)	$(211)	$(209)	$(206)	$(208)
7.95% Senior Notes Series F, due 2032 (2)(5)	$(225)	$(235)	$(224)	$(241)

(1) Carrying amount includes an unamortized discount of $3 million as of September 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 $98 million and $9 million of cash posted as collateral, as of September 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 September 30, 2015 and December 31, 2014 include unamortized discounts of $115 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").
(7) Carrying amounts for the equipment financing agreement include unamortized discounts of $11 million as of September 30, 2015. In addition, the fair value is classified as Level 3 within the fair value hierarchy levels.

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

Note 7—Accumulated Other Comprehensive Income

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

	Nine Months Ended September 30,	
(amounts in millions)	2015	2014
Beginning of period	$20	$58
Other comprehensive loss before reclassifications:		
Actuarial gain (loss) and plan amendments (net of tax of $2 and zero, respectively)	7	(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)	(3)	(3)
Net current period other comprehensive income (loss), net of tax	4	(5)
End of period	$24	$53

(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)	September 30, 2015	December 31, 2014
Materials and supplies	$177	$83
Coal (1)	270	119
Fuel oil (1)	17	3
Emissions allowances (2)	64	2
Other	3	1
Total	$531	$208

(1) At September 30, 2015, approximately $36 million and $16 million of the coal and fuel oil inventory, respectively, are part of an inventory financing agreement. At December 31, 2014, there were no amounts that were part of an inventory financing agreement. Please read Note 13—Debt—Brayton Point Inventory Financing for further discussion.

(2) At September 30, 2015, a portion of this inventory was held as collateral by one of our counterparties as part of an inventory financing agreement. At December 31, 2014, there were no amounts that were part of an inventory financing agreement. Please read Note 13—Debt—Emissions Repurchase Agreements for further discussion.

Note 9—Property, Plant and Equipment

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

(amounts in millions)	September 30, 2015	December 31, 2014
Power generation	$8,217	$3,174
Buildings and improvements	952	457
Office and other equipment	100	54
Property, plant and equipment	9,269	3,685
Accumulated depreciation	(784)	(430)
Property, plant and equipment, net	$8,485	$3,255

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

On November 5, 2015, Dynegy announced that it expects to retire the final two units at its Wood River Power Station ("Wood River") in mid-2016, subject to the approval of MISO. The decision to retire Wood River was the result of a strategic review performed in the third quarter, and was primarily attributable to its uneconomic operation stemming from a poorly designed wholesale capacity market that mixes out-of-state regulated generators, that receive rate based compensation from their home states to recover costs, with Central and Southern Illinois competitive generators that rely on the capacity market for fair compensation to recover costs. As a result of these factors, we performed an impairment analysis, which indicated that Wood River had a negative value. Therefore, we recorded an impairment charge of $74 million in Impairments and other charges in our unaudited consolidated statements of operations for the three and nine months ended September 30, 2015 to write off the entire carrying value. The fair value of Wood River was determined using a discounted cash flow model, assuming normal operations for the remainder of its estimated useful life. For the model, gross margin was based on publicly available forward market quotes, operations and maintenance expenses were based on current forecasts, and capital expenditures assumed the minimum of cash expenditures required to continue running the plant until its anticipated retirement. The valuation is classified as Level 3 within the fair value hierarchy levels.

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, 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 statements of operations.

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

	September 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	%	$202	$(11)	$6	$197
J.M. Stuart (2)(3)	39.0	%	$32	$(3)	$12	$41
Conesville (Unit 4) (2)(3)	40.0	%	$61	$(1)	$3	$63
W.H. Zimmer (2)	46.5	%	$87	$(7)	$10	$90
Killen Station (1)(3)	33.0	%	$17	$(1)	$2	$18

(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.

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

Note 11—Intangible Assets and Liabilities

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

(amounts in millions)	September 30, 2015 Gross Carrying Amount	September 30, 2015 Accumulated Amortization	September 30, 2015 Net Carrying Amount	December 31, 2014 Gross Carrying Amount	December 31, 2014 Accumulated Amortization	December 31, 2014 Net Carrying Amount
Intangible Assets:						
Electricity contracts	$260	$(100)	$160	$111	$(46)	$65
Coal contracts	—	—	—	—	—	—
Gas transport contracts	46	(4)	42	—	—	—
Total intangible assets	$306	$(104)	$202	$111	$(46)	$65
Intangible Liabilities:						
Electricity contracts	$(30)	$15	$(15)	$(20)	$14	$(6)
Coal contracts	(134)	64	(70)	(41)	22	(19)
Coal transport contracts	(104)	56	(48)	(81)	32	(49)
Gas transport contracts	(64)	26	(38)	(24)	17	(7)
Total intangible liabilities	$(332)	$161	$(171)	$(166)	$85	$(81)
Intangible assets and liabilities, net	$(26)	$57	$31	$(55)	$39	$(16)

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

(amounts in millions)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Electricity contracts, net (1)	$21	$16	$53	$77
Coal contracts, net (2)	(19)	(3)	(42)	(11)
Coal transport contracts, net (2)	(9)	(8)	(24)	(22)
Gas transport contracts, net (2)	(2)	(2)	(5)	(6)
Total	$(9)	$3	$(18)	$38

(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.

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

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

(amounts in millions/months)	EquiPower Acquisition Gross Carrying Amount	EquiPower Acquisition Weighted-Average Amortization Period	Duke Midwest Acquisition Gross Carrying Amount	Duke Midwest Acquisition Weighted-Average Amortization Period
Intangible Assets:				
Electricity contracts	$71	32	$80	38
Coal contracts	—	—	—	9
Gas transport contracts	40	24	4	19
Total intangible assets	$111	29	$84	37
Intangible Liabilities:				
Electricity contracts	$—	—	$(10)	23
Coal contracts	(10)	21	(83)	27
Coal transport contracts	(23)	22	—	—
Gas contracts	—	1	—	—
Gas transport contracts	(40)	128	—	—
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 September 30, 2015 is as follows: 2015—$8 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)	September 30, 2015
Balance, December 31, 2014	$224
Accretion expense	15
Liabilities settled in the current period	(4)
Acquisitions	105
Balance, September 30, 2015	$340

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

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

(amounts in millions)	September 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	782	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	127	23
Equipment Financing Agreements	74	—
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
	7,408	7,236
Unamortized discounts on debt, net	(129)	(130)
	7,279	7,106
Less: Current maturities, including unamortized discounts, net	71	31
Total Long-term debt	$7,208	$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 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 closed on August 17, 2015. The terms of the exchange notes are identical in all material respects to the terms of the Notes, except that the exchange notes have been registered under the Securities Act. We received no proceeds from these exchange offers.

Credit Agreement

As of September 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 September 30, 2015, there were no amounts drawn on the Revolving Facility; however, we had outstanding letters of credit of approximately $430 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 September 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).

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

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.

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 September 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 agreement (the “Inventory Financing Agreement”) 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 Agreement terminates, and our obligation becomes due and payable, on May 31, 2017, and is secured by a guaranty from Dynegy. As of September 30, 2015, our line of credit balance was $23 million, of which approximately $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 September 30, 2015, the line of credit bears interest at 8.28 percent.

Emissions Repurchase Agreements. On August 14, 2015, we entered into a repurchase transaction with a third party in which we sold approximately $58 million of Regional Greenhouse Gas Initiative (“RGGI”) inventory and received cash.

We are obligated to repurchase a portion of the inventory in February 2017 and the remaining inventory in February 2018 at a specified price with an annualized carry cost of approximately 3.56 percent. On August 20, 2015, we entered into an additional repurchase transaction with a third party in which we sold $20 million of RGGI inventory and received cash. We are obligated to repurchase the additional RGGI inventory in February 2017 at a specified price with an annualized carry cost of approximately 3.31 percent.

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

In 2013, we entered into two repurchase transactions in which we sold $6 million in California Carbon Allowance (“CCA”) credits and $11 million of 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.

Equipment Financing Agreements

Under certain of our contractual service agreements in which we receive maintenance and capital improvements for our gas-fueled generation fleet, we have obtained parts and equipment intended to increase the output, efficiency and availability of our generation units. We have financed these parts and equipment under agreements with maturities ranging from 2017 to 2025, and the future payments will be classified as financing activities in our consolidated statements of cash flows. As of September 30, 2015, there was $74 million outstanding under these agreements. The related assets were recorded at the net present value of the payments of $63 million. The $11 million discount will be amortized as interest expense over the life of the payments.

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 September 30, 2015, IPM had approximately $7 million deposited with the issuing bank and approximately $7 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 expires in May 2016. At September 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 September 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 $779 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 contingencies and adjusts its assessments 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.

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

In addition to the matters discussed below, we are party to other routine proceedings arising in the ordinary course of business. 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 "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 could 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 and plaintiffs did not appeal to the U.S. Supreme Court.

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. The remaining cases are consolidated in a multi-district litigation proceeding pending in the United States District Court for Nevada. In October 2015, the court issued a scheduling order including various discovery and pleading deadlines through 2016. At this time we cannot reasonably estimate a potential loss.

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 appealed the $17 million and $2.5 million interest judgment in March 2015, which remains pending.

Other Contingencies

MISO 2015-2016 Planning Resource Auction. In May 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 its 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.

On October 1, 2015, FERC issued an order of non-public, formal investigation, stating that shortly after the conclusion of the 2015-2016 PRA, FERC's Office of Enforcement began a non-public informal investigation into whether market manipulation or other potential violations of FERC orders, rules and regulations occurred before or during the PRA (the "Order"). The Order noted that the investigation is ongoing, and that the order converting the informal, non-public investigation to a formal, non-public investigation does not indicate that FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule or regulation. Further, FERC held a Staff-led technical conference on October 20, 2015 to obtain further information concerning potential changes to the MISO PRA structure going forward, including proposals made by complainants. The technical conference did not address the ongoing Office of Enforcement investigation.

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.

In response to the Hennepin report, we made capital improvements to the Hennepin east CCR surface impoundment berms and notified the EPA of our intent to close the Hennepin west CCR surface impoundment. The preliminary estimated cost for closure of the west CCR surface impoundment, including post-closure monitoring, is approximately $5 million, which is reflected in our asset retirement obligation ("ARO"). We performed further studies needed to support closure of the west CCR surface impoundment, submitted those studies to the Illinois EPA in August 2014 and await Illinois EPA action.

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 and our assessment of the federal EPA's CCR rule. 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. The NOV remains unresolved. 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.

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

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 July 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. 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. We await Illinois EPA action on our proposed corrective action plans. 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.

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

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. We await Illinois EPA action on our proposed corrective action plans and recommendations and continue to evaluate the impact of the federal EPA’s CCR rule. 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.

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 exceedances and recommends various measures to minimize the effects of that source on the groundwater monitoring results of the active landfill. In September 2015, we submitted an assessment monitoring report to the Illinois EPA concerning the Duck Creek facility’s active CCR landfill. The report concluded that there is no apparent release through the composite liner system of the landfill and that the previously reported groundwater quality standard exceedances appear to have resulted from stormwater discharges. We regraded the stormwater drainage system in January 2015 to prevent such discharges. The report also proposes establishment of a groundwater management zone.

In April 2013, Ameren Energy Resources Company filed a proposed site-specific rulemaking with the Illinois Pollution Control Board (“IPCB”) which, if approved, would provide for the systematic and eventual closure of our 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 Illinois EPA’s proposed rulemaking has been stayed since May 2015 to consider the implications of the federal EPA’s CCR rule. The site-specific rulemaking proposal has also been stayed.

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 September 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

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

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 September 30, 2015, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $357 million and $432 million in the event all contracts are terminated by us or the counterparty, respectively.

Coal Commitments. During the nine months ended September 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 $414 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 nine months ended September 30, 2015, we executed or assumed through our Acquisitions new long term coal transportation contracts for our generation facilities with aggregate minimum commitments of $388 million.

Gas Transportation. During the nine months ended September 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 $141 million.

Charter Agreements. 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 an 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 $4 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.

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, 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 are no longer in effect under 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 September 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 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 September 30, 2015. 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 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 September 30, 2015. Dynegy has guaranteed, up to a 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 September 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 September 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. For the three month period ending September 30, 2015, we have adjusted the fair value of the deferred tax liability acquired from EquiPower by $24 million resulting in the reduction of the previously recognized tax benefit for the release of the valuation allowance by $21 million. In addition we recorded a tax expense of $7 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.

For the nine month period ending September 30, 2015, we have a tax benefit of $459 million for the release 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 $14 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 other comprehensive income and increased our net liability by approximately $5 million during the second quarter of 2015.

In August 2015, we finalized certain new collective bargaining agreements that resulted in amendments to certain pension and other post-employment benefit plans. As a result of these amendments, we remeasured our benefit obligations and the funded status of the affected plans using inputs as of July 31, 2015. We recorded a gain through other comprehensive income and decreased our net liability by approximately $15 million during the third 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.

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

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

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

	Pension Benefits		Other Benefits	
	Nine Months Ended September 30,			
(amounts in millions)	2015	2014	2015	2014
Service cost benefits earned during period	$11	$9	$1	$—
Interest cost on projected benefit obligation	13	13	3	3
Expected return on plan assets	(17)	(16)	(3)	(3)
Amortization of prior service credit	(1)	(1)	(2)	(2)
Net periodic benefit cost (gain)	$6	$5	$(1)	$(2)

Note 17—Capital Stock

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 have been and will continue to be purchased in the open market or privately negotiated transactions from time to time at management's discretion at prevailing market prices. As of September 30, 2015, we had repurchased 4,996,299 shares at an aggregate cost of $127 million. From October 1 to October 13, 2015, we repurchased an additional 2,629,056 shares at an aggregate cost of $60 million.

Dividends

We pay quarterly dividends on our Mandatory Convertible Preferred Stock on February 1, May 1, August 1, and November 1 of each year, if declared by our Board of Directors. For the period from January 1, 2015 to September 30, 2015, we paid an aggregate of $17 million in dividends. We paid no dividends during 2014.

On October 2, 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 August 1, 2015 and ending on October 31, 2015. Such dividends were paid on November 2, 2015 to stockholders of record as of October 15, 2015.

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

Note 18—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 nine months ended September 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 September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	2015	2014	2015	2014
Income (loss) from continuing operations	$(24)	$(5)	$181	$(164)
Less: Net income (loss) attributable to noncontrolling interest	—	—	(3)	5
Income (loss) from continuing operations attributable to Dynegy Inc.	(24)	(5)	184	(169)
Less: Dividends on preferred stock	5	—	16	—
Income (loss) from continuing operations attributable to Dynegy Inc. common stockholders for basic earnings (loss) per share	(29)	(5)	168	(169)
Add: Dividends on preferred stock	5	—	16	—
Adjusted income (loss) from continuing operations attributable to Dynegy Inc. common stockholders for diluted earnings (loss) per share	$(24)	$(5)	$184	$(169)
Basic weighted-average shares	126	100	126	100
Effect of dilutive securities (1)	—	—	14	—
Diluted weighted-average shares	126	100	140	100
Earnings (loss) per share from continuing operations attributable to Dynegy Inc. common stockholders:				
Basic	$(0.23)	$(0.05)	$1.33	$(1.69)
Diluted (1)	$(0.23)	$(0.05)	$1.31	$(1.69)

(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 months ended September 30, 2015 and the three and nine months ended September 30, 2014.

For the three and nine months ended September 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions of shares)	2015	2014	2015	2014
Stock options	1.8	1.4	—	1.4
Restricted stock units	1.5	1.1	—	1.1
Performance stock units	0.6	0.3	—	0.3
Warrants	15.6	15.6	15.6	15.6
Series A 5.375% mandatory convertible preferred stock	12.9	—	—	—
Total	32.4	18.4	15.6	18.4

Note 19—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

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

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 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 September 30, 2015 and December 31, 2014.
Condensed Consolidating Balance Sheet as of September 30, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$579	$ 176	$ 179	$ —	$ 934
Accounts receivable, net	503	1,397	169	(1,633)	436
Inventory	—	316	215	—	531
Other current assets	26	287	66	(13)	366
Total Current Assets	1,108	2,176	629	(1,646)	2,267
Property, Plant and Equipment, Net	—	7,875	610	—	8,485
Other Assets					
Investment in affiliates	13,042	189	—	(13,042)	189
Goodwill	—	818	—	—	818
Other assets	136	211	55	(4)	398
Intercompany note receivable	13	—	—	(13)	—
Total Assets	$14,299	$ 11,269	$ 1,294	$ (14,705)	$ 12,157
Current Liabilities					
Accounts payable	$1,289	$ 228	$ 431	$ (1,633)	$ 315
Other current liabilities	247	292	169	(13)	695
Total Current Liabilities	1,536	520	600	(1,646)	1,010
Debt, long-term portion	6,372	126	710	—	7,208
Intercompany note payable	3,042	—	13	(3,055)	—
Other liabilities	168	396	198	(4)	758
Total Liabilities	11,118	1,042	1,521	(4,705)	8,976
Stockholders' Equity					
Dynegy Stockholders' Equity	3,181	13,269	(226)	(13,042)	3,182
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	3,181	10,227	(226)	(10,000)	3,182
Noncontrolling interest	—	—	(1)	—	(1)
Total Equity	3,181	10,227	(227)	(10,000)	3,181
Total Liabilities and Equity	$14,299	$ 11,269	$ 1,294	$ (14,705)	$ 12,157

36

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 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	—	672	176	(592)	270
Inventory	—	—	88	120	—	208
Other current assets	9	6	125	73	—	213
Total Current Assets	1,665	119	939	543	(592)	2,674
Property, Plant and Equipment, Net	—	—	2,812	443	—	3,255
Other Assets						
Investment in affiliates	6,133	—	—	—	(6,133)	—
Restricted cash	—	5,100	—	—	—	5,100
Other assets	46	47	53	57	—	203
Intercompany note receivable	17	—	—	—	(17)	—
Total Assets	$7,861	$5,266	$ 3,804	$ 1,043	$ (6,742)	$ 11,232
Current Liabilities						
Accounts payable	$310	$166	$ 112	$ 220	$ (592)	$ 216
Other current liabilities	51	67	250	97	—	465
Total Current Liabilities	361	233	362	317	(592)	681
Debt, long-term portion	1,277	5,100	—	698	—	7,075
Intercompany note payable	3,042	—	—	17	(3,059)	—
Other liabilities	158	—	105	190	—	453
Total Liabilities	4,838	5,333	467	1,222	(3,651)	8,209
Stockholders’ Equity						
Dynegy Stockholders’ Equity	3,023	(67)	6,379	(179)	(6,133)	3,023
Intercompany note receivable	—	—	(3,042)	—	3,042	—
Total Dynegy Stockholders’ Equity	3,023	(67)	3,337	(179)	(3,091)	3,023
Noncontrolling interest	—	—	—	—	—	—
Total Equity	3,023	(67)	3,337	(179)	(3,091)	3,023
Total Liabilities and Equity	$7,861	$5,266	$ 3,804	$ 1,043	$ (6,742)	$ 11,232

37

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

Condensed Consolidating Statements of Operations for the Three Months Ended September 30, 2015

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 878	$ 249	$ 105	$ 1,232
Cost of sales, excluding depreciation expense	—	(369)	(147)	(105)	(621)
Gross margin	—	509	102	—	611
Operating and maintenance expense	—	(154)	(65)	—	(219)
Depreciation expense	—	(149)	(25)	—	(174)
Impairments and other charges	—	(74)	—	—	(74)
General and administrative expense	3	(26)	(6)	—	(29)
Acquisition and integration costs	—	(8)	—	—	(8)
Operating income (loss)	3	98	6	—	107
Equity in earnings from investments in affiliates	53	—	—	(53)	—
Losses from unconsolidated investments	—	(4)	—	—	(4)
Interest expense	(127)	—	(18)	—	(145)
Other income and expense, net	47	(1)	—	—	46
Income (loss) before income taxes	(24)	93	(12)	(53)	4
Income tax benefit (expense)	—	(45)	17	—	(28)
Net income (loss)	(24)	48	5	(53)	(24)
Less: Net income attributable to noncontrolling interest	—	—	—	—	—
Net income (loss) attributable to Dynegy Inc.	$(24)	$ 48	$ 5	$ (53)	$ (24)

Condensed Consolidating Statements of Operations for the Nine Months Ended September 30, 2015

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 2,186	$ 672	$ (4)	$ 2,854
Cost of sales, excluding depreciation expense	—	(1,080)	(418)	4	(1,494)
Gross margin	—	1,106	254	—	1,360
Operating and maintenance expense	—	(385)	(195)	—	(580)
Depreciation expense	—	(352)	(61)	—	(413)
Impairments and other charges	—	(74)	—	—	(74)
Loss on sale of assets, net	—	(1)	—	—	(1)
General and administrative expense	—	(69)	(25)	—	(94)
Acquisition and integration costs	—	(121)	—	—	(121)
Operating income (loss)	—	104	(27)	—	77
Equity in earnings from investments in affiliates	500	—	—	(500)	—
Losses from unconsolidated investments	—	(1)	—	—	(1)
Interest expense	(361)	—	(52)	—	(413)
Other income and expense, net	45	—	—	—	45

Income (loss) before income taxes	184	103	(79)	(500)	(292)
Income tax benefit (expense)	—	473	—	—	473
Net income (loss)	184	576	(79)	(500)	181
Less: Net loss attributable to noncontrolling interest	—	—	(3)	—	(3)
Net income (loss) attributable to Dynegy Inc.	$ 184	$ 576	$ (76)	$ (500)	$ 184

38

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

Condensed Consolidating Statements of Operations for the Three Months Ended September 30, 2014

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 379	$ 236	$ —	$ 615
Cost of sales, excluding depreciation expense	—	(229)	(158)	—	(387)
Gross margin	—	150	78	—	228
Operating and maintenance expense	—	(65)	(49)	—	(114)
Depreciation expense	—	(51)	(10)	—	(61)
Gain on sale of assets, net	—	3	—	—	3
General and administrative expense	(3)	(13)	(9)	—	(25)
Acquisition and integration costs	—	—	(9)	—	(9)
Operating income (loss)	(3)	24	1	—	22
Equity in earnings from investments in affiliates	17	—	—	(17)	—
Interest expense	(18)	(1)	(14)	1	(32)
Other income and expense, net	5	—	1	(1)	5
Income (loss) before income taxes	1	23	(12)	(17)	(5)
Income tax benefit (expense)	(6)	—	6	—	—
Net income (loss)	(5)	23	(6)	(17)	(5)
Less: Net income attributable to noncontrolling interest	—	—	—	—	—
Net income (loss) attributable to Dynegy Inc.	$ (5)	$ 23	$ (6)	$ (17)	$ (5)

Condensed Consolidating Statements of Operations for the Nine Months Ended September 30, 2014

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 1,279	$ 619	$ —	$ 1,898
Cost of sales, excluding depreciation expense	—	(857)	(447)	—	(1,304)
Gross margin	—	422	172	—	594
Operating and maintenance expense	—	(210)	(150)	—	(360)
Depreciation expense	—	(157)	(28)	—	(185)
Gain on sale of assets, net	—	17	—	—	17
General and administrative expense	(7)	(42)	(31)	—	(80)
Acquisition and integration costs	—	—	(17)	—	(17)
Operating income (loss)	(7)	30	(54)	—	(31)
Equity in losses from investments in affiliates	(60)	—	—	60	—
Earnings from unconsolidated investments	—	10	—	—	10
Interest expense	(62)	(1)	(42)	1	(104)
Other income and expense, net	(40)	—	1	(1)	(40)
Income (loss) before income taxes	(169)	39	(95)	60	(165)
Income tax benefit	—	—	1	—	1

Net income (loss)	(169)	39	(94)	60	(164)
Less: Net income attributable to noncontrolling interest	—	—	5	—	5
Net income (loss) attributable to Dynegy Inc.	$(169)	$ 39	$ (99)	$ 60	$ (169)

39

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

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$(24)	$48	$5	$(53)	$(24)
Other comprehensive income (loss) before reclassifications:					
Actuarial gain and plan amendments, net of tax of $2	6	—	7	—	13
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 from investment in affiliates	7	—	—	(7)	—
Other comprehensive income (loss), net of tax	12	—	7	(7)	12
Comprehensive income (loss)	(12)	48	12	(60)	(12)
Less: Comprehensive income attributable to noncontrolling interest	1	—	1	(1)	1
Total comprehensive income (loss) attributable to Dynegy Inc.	$(13)	$48	$11	$(59)	$(13)

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$184	$576	$(79)	$(500)	$181
Other comprehensive income (loss) before reclassifications:					
Actuarial gain (loss) and plan amendments, net of tax of $2	1	—	7	—	8
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(3)	—	—	—	(3)
Other comprehensive income from investment in affiliates	7	—	—	(7)	—
Other comprehensive income (loss), net of tax	5	—	7	(7)	5
Comprehensive income (loss)	189	576	(72)	(507)	186
Less: Comprehensive loss attributable to noncontrolling interest	1	—	(2)	(1)	(2)
Total comprehensive income (loss) attributable to Dynegy Inc.	$188	$576	$(70)	$(506)	$188

40

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

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended September 30, 2014
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$(5)	$ 23	$ (6)	$ (17)	$ (5)
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 loss, net of tax	(1)	—	—	—	(1)
Comprehensive income (loss)	(6)	23	(6)	(17)	(6)
Less: Comprehensive income attributable to noncontrolling interest	—	—	—	—	—
Total comprehensive income (loss) attributable to Dynegy Inc.	$(6)	$ 23	$ (6)	$ (17)	$ (6)

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Nine Months Ended September 30, 2014
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$(169)	$ 39	$ (94)	$ 60	$ (164)
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	(3)	—	—	—	(3)
Other comprehensive income (loss) from investment in affiliates	(3)	—	—	3	—
Other comprehensive income (loss), net of tax	(6)	—	(3)	3	(6)
Comprehensive income (loss)	(175)	39	(97)	63	(170)
Less: Comprehensive income (loss) attributable to noncontrolling interest	(1)	—	4	1	4
Total comprehensive income (loss) attributable to Dynegy Inc.	$(174)	$ 39	$ (101)	$ 62	$ (174)

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

Condensed Consolidating Statements of Cash Flow for the Nine Months Ended September 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	$(141)	$ 502	$ (59)	$ —	$ 302
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	(8)	(122)	(41)	—	(171)
Acquisitions, net of cash acquired	(6,207)	29	100	—	(6,078)
Decrease in restricted cash	5,148	—	—	—	5,148
Net intercompany transfers	349	—	—	(349)	—
Distributions from unconsolidated affiliates	—	8	—	—	8
Other investing	—	(6)	—	—	(6)
Net cash provided by (used in) investing activities	(718)	(91)	59	(349)	(1,099)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	—	78	10	—	88
Repayments of borrowings	(6)	(23)	—	—	(29)
Financing costs from debt issuance	(31)	—	—	—	(31)
Financing costs from equity issuance	(6)	—	—	—	(6)
Dividends paid	(17)	—	—	—	(17)
Net intercompany transfers	—	(344)	(5)	349	—
Interest rate swap settlement payments	(13)	—	—	—	(13)
Repurchase of common stock	(127)	—	—	—	(127)
Other financing	(4)	—	—	—	(4)
Net cash provided by (used in) financing activities	(204)	(289)	5	349	(139)
Net increase (decrease) in cash and cash equivalents	(1,063)	122	5	—	(936)
Cash and cash equivalents, beginning of period	1,642	54	174	—	1,870
Cash and cash equivalents, end of period	$579	$ 176	$ 179	$ —	$ 934

Condensed Consolidating Statements of Cash Flow for the Nine Months Ended September 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	$(40)	$ 315	$ 1	$ —	$ 276
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(51)	(43)	—	(94)
Proceeds from asset sales, net	—	17	—	—	17

Net intercompany transfers	198	—	—	(198)	—
Net cash provided by (used in) investing activities	198	(34)	(43)	(198)	(77)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings, net of financing costs	(2)	12	—	—	10
Repayments of borrowings	(6)	—	—	—	(6)
Net intercompany transfers	—	(243)	45	198	—
Interest rate swap settlement payments	(13)	—	—	—	(13)
Other financing	(1)	—	—	—	(1)
Net cash provided by (used in) financing activities	(22)	(231)	45	198	(10)
Net increase in cash and cash equivalents	136	50	3	—	189
Cash and cash equivalents, beginning of period	474	154	215	—	843
Cash and cash equivalents, end of period	$610	$ 204	$ 218	$ —	$ 1,032

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

Note 20—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).
Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the three and nine months ended September 30, 2015 and 2014 is presented below:
Segment Data as of and for the Three Months Ended September 30, 2015

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$402	$220	$609	$1	$1,232
Intercompany revenues	(6)	1	6	(1)	—
Total revenues	$396	$221	$615	$—	$1,232
Depreciation expense	$(39)	$(8)	$(126)	$(1)	$(174)
General and administrative expense	—	—	—	(29)	(29)
Acquisition and integration costs	—	—	—	(8)	(8)
Operating income (loss)	$(36)	$31	$152	$(40)	$107
Losses from unconsolidated investments	—	—	(4)	—	(4)
Interest expense	—	—	—	(145)	(145)
Other income and expense, net	—	—	—	46	46
Income before income taxes					4
Income tax expense	—	—	—	(28)	(28)
Net loss					(24)
Less: Net income attributable to noncontrolling interest					—
Net loss attributable to Dynegy Inc.					$(24)
Total assets—domestic	$2,426	$993	$7,948	$790	$12,157
Investment in unconsolidated affiliate	$—	$—	$189	$—	$189
Capital expenditures	$(25)	$(12)	$(29)	$(3)	$(69)

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

Segment Data as of and for the Nine Months Ended September 30, 2015

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$862	$625	$1,364	$3	$2,854
Intercompany revenues	(17)	—	20	(3)	—
Total revenues	$845	$625	$1,384	$—	$2,854
Depreciation expense	$(96)	$(24)	$(290)	$(3)	$(413)
General and administrative expense	—	—	—	(94)	(94)
Acquisition and integration costs	—	—	—	(121)	(121)
Operating income (loss)	$(34)	$39	$290	$(218)	$77
Losses from unconsolidated investments	—	—	(1)	—	(1)
Interest expense	—	—	—	(413)	(413)
Other income and expense, net	—	—	—	45	45
Loss before income taxes					(292)
Income tax benefit	—	—	—	473	473
Net income					181
Less: Net loss attributable to noncontrolling interest					(3)
Net income attributable to Dynegy Inc.					$184
Total assets—domestic	$2,426	$993	$7,948	$790	$12,157
Investment in unconsolidated affiliate	$—	$—	$189	$—	$189
Capital expenditures	$(44)	$(41)	$(78)	$(8)	$(171)

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

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

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$132	$237	$246	$—	$615
Intercompany revenues	5	(1)	(4)	—	—
Total revenues	$137	$236	$242	$—	$615
Depreciation expense	$(14)	$(10)	$(36)	$(1)	$(61)
Gain on sale of assets, net	—	—	3	—	3
General and administrative expense	—	—	—	(25)	(25)
Operating income (loss)	$(2)	$19	$40	$(35)	$22
Earnings from unconsolidated investments	—	—	—	—	—
Interest expense	—	—	—	(32)	(32)
Other income and expense, net	—	1	—	4	5
Loss before income taxes					(5)
Income tax benefit	—	—	—	—	—
Net loss					(5)
Less: Net income attributable to noncontrolling interest					—
Net loss attributable to Dynegy Inc.					$(5)
Total assets—domestic	$1,100	$1,021	$2,189	$737	$5,047
Capital expenditures	$(10)	$(12)	$(2)	$(1)	$(25)

45

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

Segment Data as of and for the Nine Months Ended September 30, 2014

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$429	$618	$851	$—	$1,898
Intercompany revenues	—	1	(1)	—	—
Total revenues	$429	$619	$850	$—	$1,898
Depreciation expense	$(39)	$(28)	$(115)	$(3)	$(185)
Gain on sale of assets, net	—	—	17	—	17
General and administrative expense	—	—	—	(80)	(80)
Operating income (loss)	$2	$(14)	$72	$(91)	$(31)
Earnings from unconsolidated investments	—	—	10	—	10
Interest expense	—	—	—	(104)	(104)
Other income and expense, net	—	1	—	(41)	(40)
Loss before income taxes					(165)
Income tax benefit	—	—	—	1	1
Net loss					(164)
Less: Net income attributable to noncontrolling interest					5
Net loss attributable to Dynegy Inc.					$(169)
Total assets—domestic	$1,100	$1,021	$2,189	$737	$5,047
Capital expenditures	$(21)	$(43)	$(27)	$(3)	$(94)

DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended September 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. As of September 30, 2015, we had repurchased 4,996,299 shares at an aggregate cost of $127 million. From October 1 to October 13, 2015, we repurchased an additional 2,629,056 shares at an aggregate cost of $60 million.

In August and September of 2015, PJM conducted its capacity auctions for its new Capacity Performance ("CP") product. Please read Outlook for further discussion.

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

47

respect to any Base Rate Loan, with steps down based on a Senior Secured Leverage Ratio. Subsequent to the delivery of our September 30, 2015 debt ratio calculations, we anticipate that we will be able to lower the interest rate margin on our Revolving Facility from 2.75 percent to 2.25 percent per annum and the commitment fees on the unutilized portion of the facility from 0.5 percent to 0.375 percent.

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 September 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 September 30, 2015:

	September 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	(485)	(20)	(505)
Revolving facilities and LC availability	995	5	1,000
Cash and cash equivalents	789	145	934
Total available liquidity (4)	$1,784	$150	$1,934

(1) Includes cash of $128 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 September 30, 2015, there was approximately $16 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 nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30,	
(amounts in millions)	2015	2014
Net cash provided by operating activities	$302	$276
Net cash used in investing activities	$(1,099)	$(77)
Net cash used in financing activities	$(139)	$(10)

Operating Activities

Historical Operating Cash Flows. Cash provided by operations totaled $302 million for the nine months ended September 30, 2015. During the period, our power generation business provided cash of $655 million primarily due to the operation of our power generation facilities and our retail operations. Corporate and other activities used cash of $357 million primarily due to interest payments on our various debt agreements of $263 million and payments for acquisition-related costs of $111 million, offset by $17 million related to the Ponderosa Pine Energy, LLC cash receipt. Changes in working capital and other, including general and administrative expenses, provided cash of $4 million, net, during the period.

Cash provided by operations totaled $276 million for the nine months ended September 30, 2014. During the period, our power generation business provided cash of $285 million primarily due to the operation of our power generation facilities and our retail operations. Corporate and other activities used cash of approximately $97 million primarily due to interest payments on our various debt agreements of $73 million and payments for acquisition-related costs of

$24 million. In addition, we had $88 million in positive working capital and other changes.

48

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 at September 30, 2015 and December 31, 2014:

(amounts in millions)	September 30, 2015	December 31, 2014
Dynegy Inc.:		
Cash (1)	$144	$14
Letters of credit	485	178
Total Dynegy Inc.	629	192
IPH:		
Cash (1) (2)	3	32
Letters of credit (3)	27	10
Total IPH	30	42
Total	$659	$234

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(1) Includes broker margin as well as other collateral postings included in Prepayments and other current assets on our unaudited consolidated balance sheets. At September 30, 2015 and December 31, 2014, $98 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 approximately $1 million and $5 million, respectively, related to Genco at September 30, 2015 and December 31, 2014.

(3) Includes letters of credit of approximately $7 million and $10 million related to the $25 million cash-backed LC facility at IPM at September 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 September 30, 2015 primarily due to acquisition-related collateral requirements and other changes in our commercial activity.

The fair value of our derivatives collateralized by first priority liens included liabilities of $191 million and $141 million at September 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:

	Nine Months Ended September 30,	
(amounts in millions)	2015	2014
Coal	$44	$21
IPH	41	43
Gas	78	27
Other	8	3
Total (1)	$171	$94

(1) Includes capitalized interest of $9 million and $15 million for the nine months ended September 30, 2015 and 2014, respectively.

Other Investing Activities. During the nine months ended September 30, 2015, we paid $6.078 billion in cash, net of cash acquired, in connection with the Acquisitions. 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 nine months ended September 30, 2014, there was a $17 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 $139 million for the nine months ended September 30, 2015 primarily due to (i) $127 million of payments related to our share repurchase program, (ii) $37 million in financing costs related to our debt and equity issuances, (iii) $29 million in repayments associated with our inventory financing agreements and term loan, (iv) $17 million in dividend payments on our Mandatory Convertible Preferred Stock and (v) $13 million in interest rate swap settlement payments, offset by $88 million in proceeds received related to inventory financing agreements. Please read Note 13—Debt and Note 17—Capital Stock for further discussion.

Cash used in financing activities totaled $10 million for the nine months ended September 30, 2014 due primarily to $13 million in interest rate swap settlement payments, $6 million in principal payments of borrowings on the Tranche B-2 Term Loan and $2 million in financing costs in connection with the Credit Agreement, Senior Notes and the Macquarie Bank letter of credit, offset by $12 million in proceeds received related to the Emissions Repurchase Agreement. 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 17—Capital Stock 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 11—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 September 30, 2015 was 30 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 September 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 September 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.

We pay quarterly dividends on our Mandatory Convertible Preferred Stock on February 1, May 1, August 1, and November 1 of each year, if declared by our Board of Directors. For the period from January 1, 2015 to September 30, 2015, we paid an aggregate of $17 million in dividends. On October 2, 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. We paid no dividends during 2014. Please read Note 17—Capital Stock for further discussion.

Table of Contents

Credit Ratings

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

	Moody’s	S&P
Dynegy Inc.:		
Corporate Family Rating	B2	B+
Senior Secured	Ba3	BB
Senior Unsecured	B3	B+
Genco:		
Senior Unsecured	B3	CCC+

On September 25, 2015, Moody’s affirmed Dynegy Inc.’s existing ratings and upgraded their outlook from stable to positive.

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 nine months ended September 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).

Consolidated Summary Financial Information — Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

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

(amounts in millions)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues	$1,232	$615	$ 617	100 %
Cost of sales, excluding depreciation expense	(621)	(387)	(234)	(60)%
Gross margin	611	228	383	168 %
Operating and maintenance expense	(219)	(114)	(105)	(92)%
Depreciation expense	(174)	(61)	(113)	(185)%
Impairments and other charges	(74)	—	(74)	NM
Gain on sale of assets, net	—	3	(3)	(100)%
General and administrative expense	(29)	(25)	(4)	(16)%
Acquisition and integration costs	(8)	(9)	1	11 %
Operating income	107	22	85	NM
Losses from unconsolidated investments	(4)	—	(4)	NM
Interest expense	(145)	(32)	(113)	NM
Other income and expense, net	46	5	41	NM
Income (loss) before income taxes	4	(5)	9	180 %
Income tax expense	(28)	—	(28)	NM
Net loss	(24)	(5)	(19)	NM
Less: Net income attributable to noncontrolling interest	—	—	—	NM
Net loss attributable to Dynegy Inc.	$(24)	$(5)	$ (19)	NM

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

	Three Months Ended September 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$396	$221	$615	$—	$1,232
Cost of sales, excluding depreciation expense	(201)	(133)	(287)	—	(621)
Gross margin	195	88	328	—	611
Operating and maintenance expense	(118)	(49)	(50)	(2)	(219)
Depreciation expense	(39)	(8)	(126)	(1)	(174)
Impairments and other charges	(74)	—	—	—	(74)
General and administrative expense	—	—	—	(29)	(29)
Acquisition and integration costs	—	—	—	(8)	(8)
Operating income (loss)	$(36)	$31	$152	$(40)	$107

53

Table of Contents

	Three Months Ended September 30, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$137	$236	$242	$—	$615
Cost of sales, excluding depreciation expense	(85)	(158)	(144)	—	(387)
Gross margin	52	78	98	—	228
Operating and maintenance expense	(40)	(49)	(25)	—	(114)
Depreciation expense	(14)	(10)	(36)	(1)	(61)
Gain on sale of assets, net	—	—	3	—	3
General and administrative expense	—	—	—	(25)	(25)
Acquisition and integration costs	—	—	—	(9)	(9)
Operating income (loss)	$(2)	$19	$40	$(35)	$22

Discussion of Consolidated Results of Operations

Revenues. Our newly acquired plants contributed to increased revenues, while mild temperatures have lowered demand in our generation areas, resulting in lower volumes and unhedged prices realized by our legacy plants, compared to 2014. Revenues increased by $617 million from $615 million for the three months ended September 30, 2014 to $1,232 million for the three months ended September 30, 2015. Gas segment revenues increased by $373 million, driven by $360 million from the newly acquired plants and $13 million from our legacy plants. This $13 million increase was primarily driven by $28 million in gains on derivative instruments, $13 million higher market capacity revenues and $5 million in lower contract amortization and other revenues, partially offset by $33 million lower revenue due to the expiration of the ConEd contract at Independence. Coal segment revenues increased by $259 million, driven by $229 million from the newly acquired plants and $30 million from our legacy plants. The $30 million increase in revenues from our legacy plants was primarily driven by $30 million in gains on derivative instruments, $11 million in higher retail and other revenues and $5 million of higher wholesale capacity revenues, offset by $16 million due to lower energy prices. IPH segment revenues decreased by $15 million primarily due to $57 million in lower energy revenues as a result of lower generation volumes and power prices, partially offset by $23 million in higher wholesale capacity revenue, $8 million in gains on derivative instruments and $11 million in higher retail and other revenues.

Cost of Sales. Cost of sales increased by $234 million from $387 million for the three months ended September 30, 2014 to $621 million for the three months ended September 30, 2015. Gas segment cost of sales increased by $143 million, driven by $167 million from the newly acquired plants, partially offset by $24 million decrease from our legacy plants. This $24 million decrease was primarily due to a reduction in natural gas prices of $41 million, offset by higher generation volumes of $15 million and higher other costs of $2 million. Coal segment cost of sales increased by $116 million, primarily driven by $113 million from the newly acquired plants and $3 million from our legacy plants due to higher retail and other costs. IPH segment cost of sales decreased by $25 million, driven by $38 million in lower coal and freight costs as a result of lower generation volumes, partially offset by $10 million in contract amortization.

Operating and Maintenance Expense. Operating and maintenance expense increased by $105 million from $114 million for the three months ended September 30, 2014 to $219 million for the three months ended September 30, 2015 primarily due to the newly acquired plants.

Depreciation Expense. Depreciation expense increased by $113 million from $61 million for the three months ended September 30, 2014 to $174 million for the three months ended September 30, 2015 primarily due to the newly acquired plants.
Impairments and Other Charges. Impairments and other charges of $74 million for the three months ended September 30, 2015 are due to our impairment of the Wood River generation facility. Please read Note 9—Property, Plant and Equipment for further discussion.
Gain on Sale of Assets. Gain on sale of assets decreased by $3 million primarily due to a $3 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 $4 million from $25 million for the three months ended September 30, 2014 to $29 million for the three months ended September 30, 2015. This increase was primarily due to higher overhead associated with the Acquisitions and higher legal fees.
Acquisition and Integration Costs. Acquisition and integration costs decreased by $1 million from $9 million for the three months ended September 30, 2014 to $8 million for the three months ended September 30, 2015. Please read Note 3—Acquisitions for further discussion.
Losses from Unconsolidated Investments. Losses from unconsolidated investments increased by $4 million from zero for the three months ended September 30, 2014 to $4 million for the three months ended September 30, 2015. We recorded $4 million in losses from our 50 percent Elwood investment during the three months ended September 30, 2015.
Interest Expense. Interest expense increased by $113 million from $32 million for the three months ended September 30, 2014 to $145 million for the three months ended September 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 $41 million from income of $5 million for the three months ended September 30, 2014 to income of $46 million for the three months ended September 30, 2015. The increase was primarily due to the change in fair value of our common stock warrants.
Income Tax Expense. We reported an income tax expense of $28 million and zero for the three months ended September 30, 2015 and 2014, respectively. During the three months ended September 30, 2015, we reduced the deferred tax liability assumed through the Acquisitions by $24 million, resulting in an offsetting reduction of the previously recognized release of the valuation allowance by $21 million. In addition, we recorded an additional tax expense of $7 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 September 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 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).

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

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

	Three Months Ended September 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(24)
Income tax expense					28
Other items, net					(46)
Interest expense					145
Losses from unconsolidated investments					4
Operating income (loss)	$(36)	$31	$152	$(40)	$107
Depreciation expense	39	8	126	1	174
Amortization expense	(13)	(5)	13	—	(5)
Losses from unconsolidated investments	—	—	(4)	—	(4)
Other items, net	—	—	—	46	46
EBITDA	(10)	34	287	7	318
Acquisition and integration costs	—	—	—	8	8
Mark-to-market adjustments	(14)	(3)	(6)	—	(23)
Change in fair value of common stock warrants	—	—	—	(45)	(45)
Impairments and other charges	74	—	—	—	74
Cash distributions from unconsolidated investments	—	—	8	—	8
Other	4	3	2	1	10
Adjusted EBITDA	$54	$34	$291	$(29)	$350

Table of Contents

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

	Three Months Ended September 30, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(5)
Other items, net					(5)
Interest expense					32
Operating income (loss)	$(2)	$19	$40	$(35)	$22
Depreciation expense	14	10	36	1	61
Amortization expense	(1)	(13)	21	—	7
Other items, net	—	1	—	4	5
EBITDA	11	17	97	(30)	95
Acquisition and integration costs	—	—	—	9	9
Mark-to-market adjustments	(12)	(4)	5	—	(11)
Change in fair value of common stock warrants	—	—	—	(6)	(6)
Gain on sale of assets, net	—	—	(3)	—	(3)
Other	2	2	(1)	3	6
Adjusted EBITDA	$1	$15	$98	$(24)	$90

Adjusted EBITDA increased by $260 million from $90 million for the three months ended September 30, 2014 to $350 million for the three months ended September 30, 2015. The increase was primarily due to the newly acquired plants and higher spark spreads at the Gas segment, higher wholesale capacity revenues at the IPH and Coal segments and improved results for the retail business, partially offset by 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 September 30, 2015 Compared to Three Months Ended September 30, 2014

Coal Segment

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

(dollars in millions, except for price information)	Three Months Ended September 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$318	$131	$ 187	143 %
Capacity	53	—	53	NM
Mark-to-market income, net	21	12	9	75 %
Contract amortization	(7)	—	(7)	NM
Other (1)	11	(6)	17	NM
Total operating revenues	396	137	259	189 %
Operating Costs				
Cost of sales	(221)	(86)	(135)	(157)%
Contract amortization	20	1	19	NM
Total operating costs	(201)	(85)	(116)	(136)%
Gross margin	195	52	143	NM
Operating and maintenance expense	(118)	(40)	(78)	(195)%
Depreciation expense	(39)	(14)	(25)	(179)%
Impairments and other charges	(74)	—	(74)	NM
Operating loss	(36)	(2)	(34)	NM
Depreciation expense	39	14	25	179 %
Amortization expense	(13)	(1)	(12)	NM
EBITDA	(10)	11	(21)	(191)%
Mark-to-market adjustments	(14)	(12)	(2)	(17)%
Impairments and other charges	74	—	74	NM
Other	4	2	2	100 %
Adjusted EBITDA	$54	$1	$ 53	NM
Million Megawatt Hours Generated (5)	9.5	4.5	5.0	111 %
IMA for Coal-Fired Facilities (2)(5)	82 %	81 %		
Average Capacity Factor for Coal-Fired Facilities (3)(5)	62 %	69 %		
Average Quoted Market On-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$33.09	$37.90	$ (4.81)	(13)%
Commonwealth Edison (NI Hub)	$34.03	$37.58	$ (3.55)	(9)%
Mass Hub	$35.52	$42.01	$ (6.49)	(15)%
AD Hub	$35.87	$39.02	$ (3.15)	(8)%
Average Quoted Market Off-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$23.37	$27.57	$ (4.20)	(15)%
Commonwealth Edison (NI Hub)	$22.93	$25.40	$ (2.47)	(10)%
Mass Hub	$21.02	$27.01	$ (5.99)	(22)%
AD Hub	$24.21	$27.91	$ (3.70)	(13)%

58

Table of Contents

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(1) For the three months ended September 30, 2015 and 2014, respectively, Other includes $8 million and ($7) million in financial settlements, $1 million and zero in natural gas sales, $1 million and zero in ancillary services and $1 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. The 2015 calculation excludes our Brayton Point facility and CTs. In 2015, the IMA for our facilities within MISO and PJM (excluding CTs) was 91 percent and 77 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 68 percent and 57 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 September 30, 2015 was $36 million compared to $2 million for the three months ended September 30, 2014. Adjusted EBITDA was $54 million during the three months ended September 30, 2015 compared to $1 million during the same period in 2014. The $53 million increase in Adjusted EBITDA was primarily due to the newly acquired plants, improved wholesale capacity revenues and higher realized power prices, net of hedges, on the legacy MISO fleet.

Table of Contents

IPH Segment

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

(dollars in millions, except for price information)	Three Months Ended September 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$173	$224	$ (51)	(23)%
Capacity	41	18	23	128%
Mark-to-market income, net	3	4	(1)	(25)%
Contract amortization	(4)	(6)	2	33%
Other (1)	8	(4)	12	NM
Total operating revenues	221	236	(15)	(6)%
Operating Costs				
Cost of sales	(142)	(177)	35	20%
Contract amortization	9	19	(10)	(53)%
Total operating costs	(133)	(158)	25	16%
Gross margin	88	78	10	13%
Operating and maintenance expense	(49)	(49)	—	—%
Depreciation expense	(8)	(10)	2	20%
Operating income	31	19	12	63%
Depreciation expense	8	10	(2)	(20)%
Amortization expense	(5)	(13)	8	62%
Other items, net	—	1	(1)	(100)%
EBITDA	34	17	17	100%
Mark-to-market adjustments	(3)	(4)	1	25%
Other	3	2	1	50%
Adjusted EBITDA	$34	$15	$ 19	127%
Million Megawatt Hours Generated	4.8	6.4	(1.6)	(25)%
IMA for IPH Facilities (2)	84%	93%		
Average Capacity Factor for IPH Facilities (3)	54%	74%		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$33.09	$37.90	$ (4.81)	(13)%
Off-Peak: Indiana (Indy Hub)	$23.37	$27.57	$ (4.20)	(15)%

(1) For the three months ended September 30, 2015 and 2014, respectively, Other includes $6 million and ($2) million in financial settlements, $1 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.

(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 income for the three months ended September 30, 2015 was $31 million compared to $19 million for the three months ended September 30, 2014. Adjusted EBITDA was $34 million during the three months ended September 30, 2015

Table of Contents

compared to $15 million during the same period in 2014. The $19 million increase in Adjusted EBITDA resulted from higher wholesale capacity revenues and higher retail gross margin.

Gas Segment

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

(dollars in millions, except for price information)	Three Months Ended September 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$443	$172	$ 271	158 %
Capacity	136	80	56	70 %
Mark-to-market income (loss), net	32	(5)	37	NM
Contract amortization	(14)	(23)	9	39 %
Other (1)	18	18	—	— %
Total operating revenues	615	242	373	154 %
Operating Costs				
Cost of sales	(288)	(146)	(142)	(97)%
Contract amortization	1	2	(1)	(50)%
Total operating costs	(287)	(144)	(143)	(99)%
Gross margin	328	98	230	235 %
Operating and maintenance expense	(50)	(25)	(25)	(100)%
Depreciation expense	(126)	(36)	(90)	NM
Gain on sale of assets, net	—	3	(3)	(100)%
Operating income	152	40	112	NM
Depreciation expense	126	36	90	NM
Amortization expense	13	21	(8)	(38)%
Losses from unconsolidated investments	(4)	—	(4)	NM
EBITDA	287	97	190	196 %
Mark-to-market adjustments	(6)	5	(11)	(220)%
Gain on sale of assets, net	—	(3)	3	100 %
Cash distributions from unconsolidated investments	8	—	8	NM
Other	2	(1)	3	NM
Adjusted EBITDA	$291	$98	$ 193	197 %
Million Megawatt Hours Generated (2) (7)	15.5	4.8	10.7	223 %
IMA for Combined Cycle Facilities (3) (7)	99 %	99 %		
Average Capacity Factor for Combined Cycle Facilities (4) (7):	72 %	51 %		
Average Market On-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$14.49	$9.65	$ 4.84	50 %
PJM West	$29.82	$26.30	$ 3.52	13 %
North of Path 15 (NP 15)	$16.25	$19.40	$ (3.15)	(16)%
New York—Zone A	$26.32	$24.58	$ 1.74	7 %
Mass Hub	$18.90	$21.22	$ (2.32)	(11)%
AD Hub	$27.28	$23.17	$ 4.11	18 %
Average Market Off-Peak Spark Spreads ($/MWh) (5):				

Commonwealth Edison (NI Hub)	$3.39	$(2.53)	$ 5.92	234 %
PJM West	$15.50	$12.48	$ 3.02	24 %
North of Path 15 (NP 15)	$8.22	$8.55	$ (0.33)	(4)%
New York—Zone A	$10.49	$9.26	$ 1.23	13 %
Mass Hub	$4.39	$6.22	$ (1.83)	(29)%
AD Hub	$15.62	$12.07	$ 3.55	29 %
Average natural gas price—Henry Hub ($/MMBtu) (6)	$2.74	$3.94	$ (1.20)	(30)%

61

Table of Contents

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(1) For the three months ended September 30, 2015 and 2014, respectively, Other includes ($25) million and ($2) million in financial settlements, $12 million and $4 million in natural gas sales, $13 million and $5 million in ancillary services, $9 million and $8 million in tolls and $9 million and $3 million in RMR, option premiums and other miscellaneous items.

(2) The three months ended September 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 September 30, 2015 was $152 million compared to $40 million for the three months ended September 30, 2014. Adjusted EBITDA totaled $291 million during the three months ended September 30, 2015 compared to $98 million during the same period in 2014. The $193 million increase in Adjusted EBITDA was primarily due to the newly acquired plants, higher hedged energy margin and improved market capacity and tolling revenue, partially offset by the expiration of the ConEd contract at Independence.

Consolidated Summary Financial Information — Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

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

(amounts in millions)	Nine Months Ended September 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues	$2,854	$1,898	$ 956	50 %
Cost of sales, excluding depreciation expense	(1,494)	(1,304)	(190)	(15)%
Gross margin	1,360	594	766	129 %
Operating and maintenance expense	(580)	(360)	(220)	(61)%
Depreciation expense	(413)	(185)	(228)	(123)%
Impairments and other charges	(74)	—	(74)	NM
Gain (loss) on sale of assets, net	(1)	17	(18)	(106)%
General and administrative expense	(94)	(80)	(14)	(18)%
Acquisition and integration costs	(121)	(17)	(104)	NM
Operating income (loss)	77	(31)	108	NM
Earnings (losses) from unconsolidated investments	(1)	10	(11)	(110)%
Interest expense	(413)	(104)	(309)	NM
Other income and expense, net	45	(40)	85	213 %
Loss before income taxes	(292)	(165)	(127)	(77)%
Income tax benefit	473	1	472	NM
Net income (loss)	181	(164)	345	210 %
Less: Net income (loss) attributable to noncontrolling interest	(3)	5	(8)	(160)%
Net income (loss) attributable to Dynegy Inc.	$184	$(169)	$ 353	209 %

62

Table of Contents

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

	Nine Months Ended September 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$845	$625	$1,384	$—	$2,854
Cost of sales, excluding depreciation expense	(423)	(402)	(669)	—	(1,494)
Gross margin	422	223	715	—	1,360
Operating and maintenance expense	(286)	(160)	(134)	—	(580)
Depreciation expense	(96)	(24)	(290)	(3)	(413)
Impairments and other charges	(74)	—	—	—	(74)
Loss on sale of assets, net	—	—	(1)	—	(1)
General and administrative expense	—	—	—	(94)	(94)
Acquisition and integration costs	—	—	—	(121)	(121)
Operating income (loss)	$(34)	$39	$290	$(218)	$77

	Nine Months Ended September 30, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$429	$619	$850	$—	$1,898
Cost of sales, excluding depreciation expense	(270)	(447)	(587)	—	(1,304)
Gross margin	159	172	263	—	594
Operating and maintenance expense	(118)	(150)	(93)	1	(360)
Depreciation expense	(39)	(28)	(115)	(3)	(185)
Gain on sale of assets, net	—	—	17	—	17
General and administrative expense	—	—	—	(80)	(80)
Acquisition and integration costs	—	(8)	—	(9)	(17)
Operating income (loss)	$2	$(14)	$72	$(91)	$(31)

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 $956 million from $1,898 million for the nine months ended September 30, 2014 to $2,854 million for the nine months ended September 30, 2015. Gas segment revenues increased by $534 million, driven by $655 million from the newly acquired plants, partially offset by $121 million in lower revenues from our legacy plants. The $121 million decrease in revenues from our legacy plants was primarily driven by $267 million in lower energy revenues as a result of lower energy prices, $92 million in lower revenue due to the expiration of the ConEd contract at Independence, partially offset by $158 million in higher revenues from gains on derivatives, $39 million improved market capacity revenues and $41 million in lower contract amortization. Coal segment revenues increased by $416 million, driven by $416 million from the newly acquired plants as our legacy plants' decrease in energy revenue was offset by gains on derivative instruments. IPH segment revenues increased by $6 million primarily due to higher revenues from gains on derivative instruments of $39 million, higher wholesale capacity revenues of $56 million, higher retail and other revenues of $130 million and contract amortization of $11 million, partially offset by $230 million lower energy revenues due to lower generation volumes and power prices.

Cost of Sales. Cost of sales increased by $190 million from $1,304 million for the nine months ended September 30, 2014 to $1,494 million for the nine months ended September 30, 2015. Gas segment cost of sales increased by $82 million, driven by $308 million from the newly acquired plants, offset by $226 million primarily due to a reduction in natural gas prices from our legacy plants. Coal segment cost of sales increased by $153 million, driven by $180 million from the newly acquired plants, partially offset by $27 million from our legacy plants. The $27 million decrease in cost of sales from our legacy plants was primarily due to $33 million in lower coal and freight costs as a result of lower generation volumes, partially offset by $6 million due to higher retail and other costs. IPH segment cost of sales decreased by $45 million, driven by $74 million in lower coal and

Table of Contents

freight costs as a result of lower generation volumes, offset by $17 million in higher retail costs and $12 million in higher contract amortization.

Operating and Maintenance Expense. Operating and maintenance expense increased by $220 million from $360 million for the nine months ended September 30, 2014 to $580 million for the nine months ended September 30, 2015 primarily due to the newly acquired plants.

Depreciation Expense. Depreciation expense increased by $228 million from $185 million for the nine months ended September 30, 2014 to $413 million for the nine months ended September 30, 2015 primarily due to the newly acquired plants.

Impairments and Other Charges. Impairments and other charges of $74 million for the nine months ended September 30, 2015 are due to our impairment of the Wood River generation facility. Please read Note 9—Property, Plant and Equipment for further discussion.

Gain (loss) on Sale of Assets. Gain (loss) on sale of assets decreased by $18 million primarily due to a $17 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 $14 million from $80 million for the nine months ended September 30, 2014 to $94 million for the nine months ended September 30, 2015. This increase was primarily due to higher overhead associated with the Acquisitions and higher legal fees.

Acquisition and Integration Costs. Acquisition and integration costs increased by $104 million from $17 million for the nine months ended September 30, 2014 to $121 million for the nine months ended September 30, 2015. Acquisition and integration costs for the nine months ended September 30, 2015 consisted of $48 million in Bridge Loan financing fees and $61 million in advisory and consulting fees related to the Acquisitions and $12 million in severance costs. Acquisition and integration costs for the nine months ended September 30, 2014 consisted of $9 million in advisory and consulting fees related to the Acquisitions and $8 million related to the acquisition of AER. Please read Note 3—Acquisitions for further discussion.

Earnings (losses) from Unconsolidated Investments. Earnings (losses) from unconsolidated investments decreased by $11 million from earnings of $10 million for the nine months ended September 30, 2014 to losses of $1 million for the nine months ended September 30, 2015. We received $10 million in cash distributions from Black Mountain during the nine months ended September 30, 2014 and recorded $1 million in losses from our 50 percent Elwood investment during the nine months ended September 30, 2015.

Interest Expense. Interest expense increased by $309 million from $104 million for the nine months ended September 30, 2014 to $413 million for the nine months ended September 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 $85 million from expense of $40 million for the nine months ended September 30, 2014 to income of $45 million for the nine months ended September 30, 2015 primarily due to the change in fair value of our common stock warrants.

Income Tax Benefit. We reported an income tax benefit of $473 million and $1 million for the nine months ended September 30, 2015 and 2014, respectively. We released $459 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 $14 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 September 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 — Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014
The following table provides summary financial data regarding our Adjusted EBITDA by segment for the nine months ended September 30, 2015:

	Nine Months Ended September 30, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net income attributable to Dynegy Inc.					$184
Loss attributable to noncontrolling interest					(3)
Income tax benefit					(473)
Other items, net					(45)
Interest expense					413
Losses from unconsolidated investments					1
Operating income (loss)	$(34)	$39	$290	$(218)	$77
Depreciation expense	96	24	290	3	413
Amortization expense	(24)	(6)	16	—	(14)
Losses from unconsolidated investments	—	—	(1)	—	(1)
Other items, net	—	—	—	45	45
EBITDA	38	57	595	(170)	520
Acquisition and integration costs	—	—	—	121	121
Loss attributable to noncontrolling interest	—	3	—	—	3
Mark-to-market adjustments	(35)	(8)	(29)	—	(72)
Change in fair value of common stock warrants	—	—	—	(43)	(43)
Impairments and other charges	74	—	—	—	74
Loss on sale of assets, net	—	—	1	—	1
Cash distributions from unconsolidated investments	—	—	8	—	8
Other	6	9	—	1	16
Adjusted EBITDA	$83	$61	$575	$(91)	$628

Table of Contents

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

	Nine Months Ended September 30, 2014				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(169)
Income attributable to noncontrolling interest					5
Income tax benefit					(1)
Other items, net					40
Interest expense					104
Earnings from unconsolidated investments					(10)
Operating income (loss)	$2	$(14)	$72	$(91)	$(31)
Depreciation expense	39	28	115	3	185
Amortization expense	(4)	(11)	57	—	42
Earnings from unconsolidated investments	—	—	10	—	10
Other items, net	—	1	—	(41)	(40)
EBITDA	37	4	254	(129)	166
Acquisition and integration costs	—	8	—	9	17
Income attributable to noncontrolling interest	—	(5)	—	—	(5)
Mark-to-market adjustments	7	34	23	—	64
Change in fair value of common stock warrants	—	—	—	43	43
Gain on sale of assets, net	—	—	(17)	—	(17)
Other	7	4	—	1	12
Adjusted EBITDA	$51	$45	$260	$(76)	$280

Adjusted EBITDA increased by $348 million from $280 million for the nine months ended September 30, 2014 to $628 million for the nine months ended September 30, 2015. The increase was primarily due to the newly acquired plants, higher market capacity revenues and retail margin related to legacy plants at the Coal and IPH segments and higher spark spreads related to legacy plants at the Gas segment, partially offset by lower realized power prices on the unhedged power sales related to legacy plants 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 — Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Coal Segment

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

(dollars in millions, except for price information)	Nine Months Ended September 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$684	$506	$ 178	35 %
Capacity	103	3	100	NM
Mark-to-market income (loss), net	38	(7)	45	NM
Contract amortization	(19)	—	(19)	NM
Other (1)	39	(73)	112	153 %
Total operating revenues	845	429	416	97 %
Operating Costs				
Cost of sales	(466)	(274)	(192)	(70)%
Contract amortization	43	4	39	NM
Total operating costs	(423)	(270)	(153)	(57)%
Gross margin	422	159	263	165 %
Operating and maintenance expense	(286)	(118)	(168)	(142)%
Depreciation expense	(96)	(39)	(57)	(146)%
Impairments and other charges	(74)	—	(74)	NM
Operating income (loss)	(34)	2	(36)	NM
Depreciation expense	96	39	57	146 %
Amortization expense	(24)	(4)	(20)	NM
EBITDA	38	37	1	3 %
Mark-to-market adjustments	(35)	7	(42)	NM
Impairments and other charges	74	—	74	NM
Other	6	7	(1)	(14)%
Adjusted EBITDA	$83	$51	$ 32	63 %
Million Megawatt Hours Generated (5)	21.7	14.4	7.3	51 %
IMA for Coal-Fired Facilities (2)(5)	80 %	88 %		
Average Capacity Factor for Coal-Fired Facilities (3)(5)	59 %	74 %		
Average Quoted Market On-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$35.17	$51.53	$ (16.36)	(32)%
Commonwealth Edison (NI Hub)	$35.44	$54.95	$ (19.51)	(36)%
Mass Hub	$53.62	$86.50	$ (32.88)	(38)%
AD Hub	$39.86	$59.29	$ (19.43)	(33)%
Average Quoted Market Off-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$25.41	$33.68	$ (8.27)	(25)%
Commonwealth Edison (NI Hub)	$23.49	$32.23	$ (8.74)	(27)%
Mass Hub	$38.90	$61.25	$ (22.35)	(36)%
AD Hub	$27.20	$36.38	$ (9.18)	(25)%

Table of Contents

(1) For the nine months ended September 30, 2015 and 2014, respectively, Other includes $36 million and ($76) million in financial settlements, $2 million and zero in natural gas sales, ($1) million and $2 million in ancillary services and $2 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. The 2015 calculation excludes our Brayton Point facility and CTs. In 2015, the IMA for our facilities within MISO and PJM (excluding CTs) was 87 percent and 73 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 66 percent and 51 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 nine months ended September 30, 2015 was $34 million compared to operating income of $2 million for the nine months ended September 30, 2014. Adjusted EBITDA was $83 million during the nine months ended September 30, 2015 compared to $51 million during the same period in 2014. The $32 million increase in Adjusted EBITDA was primarily due to a positive impact related to the newly acquired plants and improved capacity revenues related to legacy plants and retail margins, partially offset by lower power prices on the unhedged portion of the legacy 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 nine months ended September 30, 2015 and 2014, respectively:

(dollars in millions, except for price information)	Nine Months Ended September 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$524	$636	$ (112)	(18)%
Capacity	83	27	56	207%
Mark-to-market income (loss), net	8	(34)	42	124%
Contract amortization	(18)	(27)	9	33%
Other (1)	28	17	11	65%
Total operating revenues	625	619	6	1%
Operating Costs				
Cost of sales	(426)	(485)	59	12%
Contract amortization	24	38	(14)	(37)%
Total operating costs	(402)	(447)	45	10%
Gross margin	223	172	51	30%
Operating and maintenance expense	(160)	(150)	(10)	(7)%
Depreciation expense	(24)	(28)	4	14%
Acquisition and integration costs	—	(8)	8	100%
Operating income (loss)	39	(14)	53	NM
Depreciation expense	24	28	(4)	(14)%
Amortization expense	(6)	(11)	5	45%
Other items, net	—	1	(1)	(100)%
EBITDA	57	4	53	NM
Acquisition and integration costs	—	8	(8)	(100)%
Income attributable to noncontrolling interest	3	(5)	8	160%
Mark-to-market adjustments	(8)	34	(42)	(124)%
Other	9	4	5	125%
Adjusted EBITDA	$61	$45	$ 16	36%
Million Megawatt Hours Generated	14.7	17.8	(3.1)	(17)%
IMA for IPH Facilities (2)	89%	89%		
Average Capacity Factor for IPH Facilities (3)	55%	69%		
Average Quoted Market Power Prices ($/MWh) (4):	—			
On-Peak: Indiana (Indy Hub)	$35.17	$51.53	$ (16.36)	(32)%
Off-Peak: Indiana (Indy Hub)	$25.41	$33.68	$ (8.27)	(25)%

69

Table of Contents

(1) For the nine months ended September 30, 2015 and 2014, respectively, Other includes $22 million and $25 million in financial settlements, $2 million and ($7) million in ancillary services and $4 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.

Operating income for the nine months ended September 30, 2015 was $39 million compared to an operating loss of $14 million for the nine months ended September 30, 2014. Adjusted EBITDA was $61 million during the nine months ended September 30, 2015 compared to $45 million during the same period in 2014. The $16 million increase in Adjusted EBITDA resulted from higher wholesale capacity revenues and higher retail gross margin, partially offset by lower generation volumes and lower power prices on unhedged power sales.

Table of Contents

Gas Segment

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

(dollars in millions, except for price information)	Nine Months Ended September 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$1,032	$743	$ 289	39 %
Capacity	270	193	77	40 %
Mark-to-market income (loss), net	74	(23)	97	NM
Contract amortization	(21)	(63)	42	67 %
Other (1)	29	—	29	NM
Total operating revenues	1,384	850	534	63 %
Operating Costs				
Cost of sales	(674)	(593)	(81)	(14)%
Contract amortization	5	6	(1)	(17)%
Total operating costs	(669)	(587)	(82)	(14)%
Gross margin	715	263	452	172 %
Operating and maintenance expense	(134)	(93)	(41)	(44)%
Depreciation expense	(290)	(115)	(175)	(152)%
Gain (loss) on sale of assets, net	(1)	17	(18)	(106)%
Operating income	290	72	218	NM
Depreciation expense	290	115	175	152 %
Amortization expense	16	57	(41)	(72)%
Earnings (losses) from unconsolidated investments	(1)	10	(11)	(110)%
EBITDA	595	254	341	134 %
Mark-to-market adjustments	(29)	23	(52)	(226)%
Gain (loss) on sale of assets, net	1	(17)	18	106 %
Cash distributions from unconsolidated investments	8	—	8	NM
Adjusted EBITDA	$575	$260	$ 315	121 %
Million Megawatt Hours Generated (2)(7)	33.2	13.0	20.2	155 %
IMA for Combined Cycle Facilities (3)(7)	98 %	99 %		
Average Capacity Factor for Combined Cycle Facilities (4)(7)	63 %	46 %		
Average Market On-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$14.91	$12.05	$ 2.86	24 %
PJM West	$25.58	$27.99	$ (2.41)	(9)%
North of Path 15 (NP 15)	$14.63	$17.23	$ (2.60)	(15)%
New York—Zone A	$29.49	$39.18	$ (9.69)	(25)%
Mass Hub	$15.77	$22.30	$ (6.53)	(29)%
AD Hub	$28.88	$34.41	$ (5.53)	(16)%
Average Market Off-Peak Spark Spreads ($/MWh) (5):				
Commonwealth Edison (NI Hub)	$2.97	$(10.67)	$ 13.64	128 %
PJM West	$10.71	$2.68	$ 8.03	NM
North of Path 15 (NP 15)	$7.75	$7.07	$ 0.68	10 %

New York—Zone A	$14.12	$15.86	$ (1.74)	(11)%
Mass Hub	$1.05	$(2.95)	$ 4.00	136 %
AD Hub	$16.22	$11.50	$ 4.72	41 %
Average natural gas price—Henry Hub ($/MMBtu) (6)	$2.78	$4.52	$ (1.74)	(38)%

Table of Contents

(1) For the nine months ended September 30, 2015 and 2014, respectively, Other includes ($64) million and ($94) million in financial settlements, $28 million and $50 million in natural gas sales, $31 million and $28 million in ancillary services, $14 million and $11 million in tolls and $20 million and $5 million in RMR, option premiums and other miscellaneous items.

(2) The nine months ended September 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 nine months ended September 30, 2015 was $290 million compared to $72 million for the nine months ended September 30, 2014. Adjusted EBITDA totaled $575 million during the nine months ended September 30, 2015 compared to $260 million during the same period in 2014. The $315 million increase in Adjusted EBITDA was primarily due to a positive impact related to the newly acquired plants, higher spark spreads and run times at our legacy PJM plants, and improved market capacity pricing and tolling revenues related to legacy plants, 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.

PRIDE Improvement Initiatives

We continue to employ our cost and performance improvement initiative, known as PRIDE, which is designed to drive recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency. In 2013, we launched PRIDE Reloaded, with a three-year target of $135 million in operating improvements and $165 million in balance sheet efficiencies. In 2014, we exceeded our $60 million EBITDA improvement target and $65 million balance sheet efficiency target, and, subsequently accelerated our original three-year target from 2016 to by the end of 2015, a full year ahead of schedule. We are currently on track to exceed the balance sheet target for 2015 of $72 million and are expecting to achieve our EBITDA target of $45 million by year-end. In September 2015, we announced the next iteration of PRIDE which includes the newly acquired assets. “PRIDE Energized” is targeted to deliver an incremental $250 million in EBITDA and $400 million in balance sheet improvements for Dynegy over the 2016-2018 time period.

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.

On November 5, 2015, Dynegy announced that it expects to retire the final two units at the 465-megawatt Wood River Power Station in Alton, Illinois, in mid-2016, subject to the approval of MISO. The decision to retire the Wood River facility was the result of a strategic review performed in the third quarter, and was primarily attributable to its uneconomic operation stemming from a poorly designed wholesale capacity market that mixes out-of-state regulated generators, that receive rate based compensation

72

from their home states to recover costs, with Central and Southern Illinois competitive generators that rely on the capacity market for fair compensation to recover costs.

As of October 19, 2015, our expected remaining generation volumes, excluding Brayton Point, are 63 percent hedged volumetrically for 2015 and approximately 47 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 October 19, 2015, excluding non-operated jointly-owned generating units, our expected coal requirements for 2015 are fully contracted and priced. Our forecasted coal requirements for 2016, excluding non-operated jointly-owned generating units, are 64 percent contracted and 61 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 facility. The contract, which begins in 2017, reflects a reduction from the 2016 rate. Our coal transportation requirements are approximately 78 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.

On September 29, 2014, the Illinois Power Agency ("IPA") issued a Request For Proposals, approved by the Illinois Commerce Commission, that included a request for capacity in Illinois for MISO Zone 4 for the 2016-2017 Planning Year. The IPA procured 1,033 MW in Zone 4 at an average price of $138.12 per MW-day. Dynegy was one of four selected suppliers.

In New England our Brayton Point facility 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 and 3,331 MW in the Planning Year 2015-2016 capacity auction. PJM introduced its new CP product beginning with Planning Year 2016-2017. In PJM, Coal cleared 3,566 MW in the Planning Year 2016-2017 (1,702 MW legacy capacity and 1,864 MW CP), 3,377 MW in the Planning Year 2017-2018 (2,027 MW legacy capacity and 1,350 MW CP). Base capacity resources (Base) are those capacity resources, beginning in Planning Year 2018-2019, that are not capable of sustained, predictable operation throughout the entire delivery year, but are capable of providing energy and reserves during hot weather operations. They are subject to non-performance charges assessed during emergency conditions, from June through September. In PJM, Coal cleared 3,347 MW in the Planning Year 2018-2019 capacity auction (1,734 MW Base and 1,613 MW CP).

IPH. The IPH segment is comprised of five plants, totaling 4,278 MW. 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. On September 24, 2015, MISO notified us that Edwards Unit 1 will no longer be needed as a System Support Resource unit. Thus, MISO authorized and we intend to retire Edwards Unit 1 effective January 1, 2016.

As of October 19, 2015, our IPH expected remaining generation volumes are approximately 63 percent hedged volumetrically for 2015 and approximately 48 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 October 19, 2015, our expected coal requirements for IPH for 2015 are fully contracted and 95 percent priced. Our forecasted coal requirements for 2016 are 79 percent contracted and 57 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.
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, 867 MW in Planning Year 2016-2017 (138 MW legacy capacity and 729 MW CP), 847 MW in Planning Year 2017-2018 (376 MW legacy capacity and 471 MW CP), and 835 MW in the Planning Year 2018-2019 capacity auction (all CP). In addition, we have also secured one segment of the transmission path required to offer an additional 240 MW of capacity and energy into PJM.

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.

In PJM we are installing a total of 260 MW of energy and capacity, which will be accomplished primarily through upgrades to the hot gas path components of our combined cycle gas turbines. The uprates start in Fall 2015 at the Hanging Rock facility and are expected to be completed in the Spring of 2017 at Liberty Electric.

In New England, we have qualified 70 MW of new uprates for participation in FCA-10, which covers Planning Year 2019-2020.

In New York, during 2016 we will be installing 45 MW of additional energy and capacity at our Independence facility.

Excluding volumes subject to tolling agreements, as of October 19, 2015, our Gas portfolio is 54 percent hedged volumetrically through 2015 and approximately 41 percent hedged volumetrically for 2016. As a result of the offsetting risks of our Gas and 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 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, 6,244 MW in Planning Year 2016-2017 (2,296 MW legacy capacity and 3,948 MW CP), 6,458 MW in Planning Year 2017-2018 (1,771 MW legacy capacity and 4,687 MW CP), and 5,708 MW in the Planning Year 2018-2019 capacity auction (all CP).

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 64 percent of our Independence facility's winter capacity had been sold bilaterally prior to the most recent auction, covering the Winter 2015-2016 planning period. As of October 19, 2015, 939 MW of capacity was sold for the Winter 2015-2016 planning period; 697 MW were sold for the Summer 2016 planning period; 336 MW were sold for the Winter 2016-2017 planning period; and 255 MW were sold for the Summer 2017 planning period.

In October 2015, we contracted resource adequacy ("RA") capacity with Southern California Edison for Moss Landing units 1 and 2 for 575 MW, 400 MW, and 850 MW, for calendar years 2017, 2018, and 2019, respectively.

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 California Public Utility Commission ("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 2015, and Oral Argument was held on

October 28, 2015. A decision is expected in late 2015.

Table of Contents

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 a Planning Reserve Margin of 15.2 percent and 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 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.

On October 1, 2015, FERC issued an order of non-public, formal investigation, stating that shortly after the conclusion of the 2015-2016 PRA, FERC's Office of Enforcement began a non-public informal investigation into whether market manipulation or other potential violations of FERC orders, rules and regulations occurred before or during the PRA. The Order noted that the investigation is ongoing, and that the order converting the informal, non-public investigation to a formal, non-public investigation does not indicate that FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. Further, FERC held a Staff-led technical conference on October 20, 2015 to obtain further information concerning potential changes to the MISO PRA structure going forward, including proposals made by complainants. The technical conference did not address the ongoing Office of Enforcement investigation. Please read Note 14—Commitments and Contingencies—Other Contingencies—MISO 2015-2016 Planning Resource Auction for further information.

ISO-NE. We have approximately 3,933 MW of power generation in ISO-NE. The most recent forward 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 Southeastern Massachusetts and Rhode Island ("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. Gas-fired plants within PJM are mixed between Eastern Mid-Atlantic Area Council ("EMAAC") (Liberty), Mid-Atlantic Area Council ("MAAC") (Ontelaunee), Commonwealth Edison ("COMED") (Elwood, Kendall, Lee), American Transmission Service, Inc. ("ATSI") (Richland/Stryker) and Regional Transmission Organization ("RTO") (balance of plants). PJM has begun the transition of the PJM capacity market to CP product. On August 26-27, 2015, PJM held a transitional auction to convert up to 60 percent of PJM's capacity needs for Planning Year 2016-2017 from legacy capacity to CP. On September 3-4, 2015, PJM held a transitional auction to convert 70 percent of PJM's capacity needs for Planning Year 2017-2018 from legacy capacity to CP. On August 10-14, 2015, PJM held the BRA to procure CP for 80 percent and Base for 20 percent of PJM's capacity needs for the Planning Year 2018-2019. PJM will procure 100 percent

Table of Contents

CP for all resources beginning with Planning Year 2020-2021. The most recent Reliability Pricing Model (“RPM”) auction results for PJM’s RTO and MAAC zones, in which our assets are located, are as follows for each Planning Year:

	2014-2015 Legacy Capacity	2015-2016 Legacy Capacity	2016-2017 Legacy Capacity	2016-2017 CP	2017-2018 Legacy Capacity	2017-2018 CP	2018-2019 Base	2018-2019 CP
RTO zone, price per MW-day	$ 125.99	$ 136.00	$ 59.37	$ 134.00	$ 120.00	$ 151.50	$ 149.98	$ 164.77
MAAC zone, price per MW-day	$ 136.50	$ 167.46	$ 119.13	$ 134.00	$ 120.00	$ 151.50	$ 149.98	$ 164.77
EMAAC zone, price per MW-day	$ 136.50	$ 167.46	$ 119.13	$ 134.00	$ 120.00	$ 151.50	$ 210.63	$ 225.42
COMED zone, price per MW-day	$ 125.99	$ 136.00	$ 59.37	$ 134.00	$ 120.00	$ 151.50	$ 200.21	$ 215.00
ATSI zone, price per MW-day	$ 125.99	$ 357.00	$ 114.23	$ 134.00	$ 120.00	$ 151.50	$ 149.98	$ 164.77

NYISO. We have approximately 1,108 MW of power generation in NYISO. The forecasted 2015 NYISO reserve margin is 24.7 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	Winter 2015-2016	Summer 2016	Winter 2016-2017	Summer 2017
Price per kW-month	$2.58	$5.15	$2.90	$3.50	$2.30	$3.48	$2.25	$2.87

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 Request for Offers (“RFO”) solicitations, broker markets, and directly with bilateral transactions. We transact both the standard 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.

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 was held on October 14, 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 CP Proposal accepted by FERC. Under PJM’s plan, existing demand response resources that cannot meet CP requirements (unlimited interruptions on an annual basis) will be allowed into the Base Capacity Product until Planning Year 2020-2021, where they will be phased out, leaving only CP 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 Forms 10-Q for the periods ended March 31, 2015 and June 30, 2015 for detailed discussions of our environmental and regulatory matters.

The Clean Air Act

National Ambient Air Quality Standards ("NAAQS"). On October 1, 2015, the EPA issued a final rule lowering the primary and secondary NAAQS for ground-level ozone from 75 to 70 parts per billion (ppb). In accordance with the CAA, the EPA anticipates designating attainment and nonattainment areas for the 2015 ozone NAAQS by October 1, 2017. State implementation plans for the 2015 ozone NAAQS generally would be due in 2020-2021. Based on the severity of nonattainment designation, nonattainment areas would be required to achieve compliance between 2020 and 2037. The nature and scope of potential future requirements concerning the 2015 ozone NAAQS cannot be predicted with confidence at this time.

Table of Contents

In August 2015, the EPA issued a final rule regarding the 2010 one-hour SO_2 NAAQS that requires air agencies to characterize air quality around sources that emit 2,000 tons per year or more of SO_2 using either ambient air quality measured at monitors or modeling of source emissions. The rule requires air agencies to identify, by July 2016, sources with SO_2 emissions above 2,000 tons per year. For source areas that will be evaluated through air quality modeling, the modeling analysis must be submitted to the EPA by January 2017. For source areas that will be evaluated through air quality monitoring, air quality data will be collected for years 2017 through 2019. The rule will lead to the development of data that informs attainment and nonattainment area designations for the 2010 one-hour SO_2 NAAQS that are required by a court order to occur over the period July 2016 through December 2020. The EPA anticipates making final designations for the majority of the country by December 2017, except for areas with new monitoring networks that begin operation in 2017 for which final designations would be made by December 2020. For areas designated nonattainment in 2017, the EPA anticipates state implementation plans (SIPs) would be due in August 2019. For areas designated nonattainment in 2020, the EPA anticipates SIPs would be due in August 2022. Areas designated nonattainment must achieve attainment no later than five years after designation.

The nature and scope of potential future requirements concerning the 2015 ozone NAAQS and 2010 one-hour SO_2 NAAQS cannot be predicted with confidence at this time. A future requirement for additional emission reductions of NOx or SO_2 at any of our coal-fired generating facilities for purposes of the 2015 ozone NAAQS or 2010 one-hour SO_2 NAAQS may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

The Clean Water Act

Effluent Limitation Guidelines (“ELG”). On September 30, 2015, the EPA issued a final rule revising the ELG for steam electric power generation units. The ELG final rule establishes new or additional requirements for wastewater streams associated with steam electric power generation processes and byproducts, including flue gas desulfurization, fly ash, bottom ash and flue gas mercury control. For EGUs greater than 50 MW, the final rule establishes a zero discharge standard for bottom ash transport water, fly ash transport water and flue gas mercury control wastewater. The rule also establishes effluent limits for flue gas desulfurization wastewaters based on chemical precipitation and biological treatment. Existing EGUs are required to comply with the discharge limits in the ELG final rule by a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023.

We are currently evaluating the ELG final rule and the 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. The ELG final rule’s zero discharge standard on bottom ash transport water on all units greater than 50 MW may add material compliance costs to our previously disclosed preliminary cost estimate of approximately $288 million for compliance with the ELG rule, which we are currently reviewing. The majority of ELG compliance spend is expected to occur in the 2018-2023 timeframe. Our estimate and timing could change significantly depending upon a variety of factors, including detailed site-specific engineering analyses, the outcome of potential litigation concerning the ELG final rule, and our final compliance plans with the EPA’s CCR rule.

Waters of the United States. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying the EPA and the U.S. Army Corps of Engineers’ final rule defining the term “waters of the United States” pending further review by the court.

Climate Change

Federal Regulation of Greenhouse Gases. On October 22, 2015, numerous states, industry associations and labor groups filed lawsuits challenging the EPA’s final rule Clean Power Plan. Numerous parties challenging the rule also filed motions to stay the rule pending completion of judicial review.

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 California Air Resources Board ("CARB") and the Province of Québec held their fourth joint allowance auction in August 2015 with current vintage auction allowances selling at a clearing price of $12.52 per metric ton and 2018 auction allowances selling at a clearing price of $12.30 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 November 2015.

Table of Contents

We estimate the cost of GHG allowances required to operate our units in California during 2015 will be approximately $16 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 September 2015, RGGI held its twenty-ninth auction, in which approximately 25.4 million allowances were sold at a clearing price of $6.02 per allowance. RGGI's next quarterly auction is scheduled for December 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 $64 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 Nine Months Ended September 30, 2015
Fair value of portfolio at December 31, 2014	$(83)
Risk management gains recognized through the statement of operations in the period, net	62
Contracts realized or otherwise settled during the period	55
Acquisitions	(235)
Changes in collateral/margin netting	89
Fair value of portfolio at September 30, 2015	$(112)

The net risk management liability of $112 million is the aggregate of the following line items on our unaudited consolidated balance sheets: Current Assets—Assets from risk management activities, Other Assets—Assets from risk management activities, Current Liabilities—Liabilities from risk management activities and Other Liabilities—Liabilities from risk management activities.

Risk Management Asset and Liability Disclosures. The following table provides an assessment of net contract values by year as of September 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)	$(148)	$(41)	$(77)	$(18)	$(8)	$(3)	$(1)
Prices based on models (2)	(62)	(4)	(10)	(40)	(10)	1	1
Total (3)	$(210)	$(45)	$(87)	$(58)	$(18)	$(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 $98 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

Table of Contents

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 wor 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 power market 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, or impacts of, 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 that we are, or could become, subject to, which could increase our costs, result in an impairment of our assets, cause us to limit or terminate the operation of certain of our facilities, or otherwise have a negative financial effect;
- 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, including managing risk associated with CP 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;
- anticipated timing, outcomes and impacts of the expected retirements of Brayton Point, Edwards Unit 1 and Wood River;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the Vermilion facility and any potential future remediation obligations at the South Bay facility; 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

79

Table of Contents

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 September 30, 2015.

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 September 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)	September 30, 2015	December 31, 2014
One day VaR—95 percent confidence level	$7	$10
One day VaR—99 percent confidence level	$9	$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 September 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	$29	$—	$29
Oil and gas producers	—	—	—
Utility and power generators	19	—	19
Total	$48	$—	$48

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.

Table of Contents

The absolute notional amounts associated with our interest rate contracts were as follows at September 30, 2015 and December 31, 2014, respectively:

	September 30, 2015	December 31, 2014
Interest rate swaps (in millions of U.S. dollars)	$779	$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 September 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 September 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 2—UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth certain information with respect to repurchases of our common stock during the quarter ended September 30, 2015.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
July 1 - July 31	—	$—	—	$—
August 1 - August 31	4,996,299	$25.37	4,996,299	$123,000,000
September 1 - September 30	—	$—	—	$—
Total	4,996,299	$25.37	4,996,299	$123,000,000

(1) 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.

Item 6—EXHIBITS

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

Exhibit Number	Description
**4.1	Fifth Supplemental Indenture to the 2019 Notes Indenture, dated September 21, 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	Fifth Supplemental Indenture to the 2022 Notes Indenture, dated September 21, 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	Fifth Supplemental Indenture to the 2024 Notes Indenture, dated September 21, 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	Fifth Supplemental Indenture to the 2023 Notes Indenture, dated September 21, 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	Amendment to Non-Qualified Stock Option Award Agreement - Flexon (2015 Employment Agreement Award).
**10.2	Amendment No. 2 to Letter of Credit and Reimbursement Agreement by and between Illinois Power Marketing Company ad Union Bank, N.A.
10.3	Form of Dynegy Inc. Executive Participation Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2015 File No. 001-33443).
10.4	Dynegy Inc. Severance Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 30, 2015 File No. 001-33443).
**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

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** Filed herewith.

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

1933, as amended, or the Exchange Act.

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:	November 5, 2015	By:	/s/ CLINT C. FREELAND Clint C. Freeland Executive Vice President and Chief Financial Officer