DYNEGY INC.
Form 10-Q
May 04, 2016
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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 March 31, 2016

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	Smaller reporting company o
(Do not check if a smaller reporting company)	

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 ¨

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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, 117,278,604 shares outstanding as of April 19, 2016.

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DEFINITIONS

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

CAA	Clean Air Act
CAISO	The California Independent System Operator
CPUC	California Public Utility Commission
CT	Combustion Turbine
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
IMA	In-market Asset Availability
IPCB	Illinois Pollution Control Board
IPH	IPH, LLC (formerly known as Illinois Power Holdings, LLC)
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LIBOR	London Interbank Offered Rate
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
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
S&P	Standard & Poor’s Ratings Services
SEC	U.S. Securities and Exchange Commission

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

	March 31, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	$ 821	$ 505
Restricted cash	37	39
Accounts receivable, net of allowance for doubtful accounts of $1 and $1, respectively	339	402
Inventory	579	597
Assets from risk management activities	177	100
Intangible assets	81	102
Prepayments and other current assets	247	187
Total Current Assets	2,281	1,932
Property, Plant and Equipment, Net	8,242	8,347
Investment in unconsolidated affiliate	185	190
Assets from risk management activities	52	18
Goodwill	797	797
Intangible assets	44	62
Other long-term assets	107	113
Total Assets	$ 11,708	$ 11,459

See the notes to consolidated financial statements.

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

	March 31, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 243	$ 292
Accrued interest	180	74
Intangible liabilities	65	85
Accrued liabilities and other current liabilities	99	125
Liabilities from risk management activities	117	103
Asset retirement obligations	51	50
Debt, current portion	108	80
Total Current Liabilities	863	809
Debt, long-term portion	7,304	7,129
Liabilities from risk management activities	120	105
Asset retirement obligations	234	230
Deferred income taxes	44	29
Intangible liabilities	50	55
Other long-term liabilities	186	183
Total Liabilities	8,801	8,540
Commitments and Contingencies (Note 13)		
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; 128,566,819 shares issued and 117,240,697 shares outstanding at March 31, 2016; 128,228,477 shares issued and 116,902,355 outstanding at December 31, 2015	1	1
Additional paid-in capital	3,186	3,187
Accumulated other comprehensive income, net of tax	18	19
Accumulated deficit	(696)	(686)
Total Dynegy Stockholders' Equity	2,909	2,921
Noncontrolling interest	(2)	(2)
Total Equity	2,907	2,919
Total Liabilities and Equity	$ 11,708	$ 11,459

See the notes to consolidated financial statements.

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

	Three Months Ended March 31, 2016	2015
Revenues	$1,123	$632
Cost of sales, excluding depreciation expense	(545)	(377)
Gross margin	578	255
Operating and maintenance expense	(221)	(111)
Depreciation expense	(171)	(64)
General and administrative expense	(37)	(30)
Acquisition and integration costs	(4)	(90)
Operating income (loss)	145	(40)
Earnings from unconsolidated investments	2	—
Interest expense	(142)	(136)
Other income and (expense), net	1	(5)
Income (loss) before income taxes	6	(181)
Income tax expense (Note 14)	(16)	—
Net loss	(10)	(181)
Less: Net loss attributable to noncontrolling interest	—	(1)
Net loss attributable to Dynegy Inc.	(10)	(180)
Less: Dividends on preferred stock	5	5
Net loss attributable to Dynegy Inc. common stockholders	$(15)	$(185)
Loss Per Share (Note 17):		
Basic and diluted loss per share attributable to Dynegy Inc. common stockholders	$(0.13)	$(1.49)
Basic and diluted shares outstanding	117	124

See the notes to consolidated financial statements.

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

	Three Months Ended March 31, 2016	2015
Net loss	$(10)	$(181)
Amounts reclassified from accumulated other comprehensive income:		
Amortization of unrecognized prior service credit and actuarial gain (net of tax of zero and zero, respectively)	(1)	(1)
Other comprehensive loss, net of tax	(1)	(1)
Comprehensive loss	(11)	(182)
Less: Comprehensive loss attributable to noncontrolling interest	—	(1)
Total comprehensive loss attributable to Dynegy Inc.	$(11)	$(181)

See the notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(10)	$(181)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation expense	171	64
Non-cash interest expense	10	7
Amortization of intangibles	14	(4)
Risk management activities	(109)	(27)
Earnings from unconsolidated investments	(2)	—
Deferred income taxes	16	—
Change in value of common stock warrants	(1)	5
Other	13	11
Changes in working capital:		
Accounts receivable, net	65	1
Inventory	18	(18)
Prepayments and other current assets	28	(10)
Accounts payable and accrued liabilities	43	83
Changes in restricted cash	2	—
Changes in non-current assets	(70)	(4)
Changes in non-current liabilities	3	18
Net cash provided by (used in) operating activities	191	(55)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(65)	(40)
Distributions from unconsolidated affiliates	8	—
Net cash used in investing activities	(57)	(40)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long term borrowings	198	—
Repayments of borrowings	(5)	(25)
Dividends paid	(5)	(7)
Interest rate swap settlement payments	(4)	(4)
Other financing	(2)	(5)
Net cash provided by (used in) financing activities	182	(41)
Net increase (decrease) in cash and cash equivalents	316	(136)
Cash and cash equivalents, beginning of period	505	1,870
Cash and cash equivalents, end of period	$821	$1,734

See the notes to consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2016 and 2015

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. Certain prior period amounts in our unaudited consolidated financial statements have been reclassified to conform to current year presentation. These interim financial statements should be read together with the consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2015, filed with the SEC on February 25, 2016, which we refer to as our "Form 10-K." Unless the context indicates otherwise, throughout this report, the terms "Dynegy," "the Company," "we," "us," "our," and "ours" are used to refer to Dynegy Inc. and its direct and indirect subsidiaries.

Our current business operations are focused primarily on the unregulated power generation sector of the energy industry. We report the results of our power generation business as three segments in our unaudited consolidated financial statements: (i) the Coal segment ("Coal"), (ii) the IPH segment ("IPH") and (iii) the Gas segment ("Gas"). Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense). All significant intercompany transactions have been eliminated. Please read Note 19—Segment Information for further discussion.

IPH and its direct and indirect subsidiaries are organized into ring-fenced groups in order to maintain corporate separateness from Dynegy and its other subsidiaries. Certain of the entities in the IPH segment, including Illinois Power Generating Company ("Genco"), have an independent director whose consent is required for certain corporate actions, including material transactions with affiliates. Further, entities within the IPH segment present themselves to the public as separate entities. They maintain separate books, records and bank accounts and separately appoint officers. Furthermore, they pay liabilities from their own funds, conduct business in their own names and have restrictions on pledging their assets for the benefit of certain other persons. These provisions restrict our ability to move cash out of these entities without meeting certain requirements as set forth in the governing documents. Genco's $825 million Senior Notes are non-recourse to Dynegy.

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 three months ended March 31, 2016.

Accounting Standards Adopted During the Current Period

Hybrid Financial Instruments. In November 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-16-Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or Equity. The amendments in this ASU clarify how current GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. Specifically, the amendments clarify that an entity should consider all relevant terms and features, including the embedded derivative feature being evaluated for bifurcation, in evaluating the nature of the host contract. Furthermore, the amendments clarify that no single term or feature would necessarily determine the economic characteristics and risks of the host contract. Rather, the nature of the host contract depends upon the economic characteristics and risks of the entire hybrid financial instrument. The amendments in this ASU also clarify that, in evaluating the nature of a host contract, an entity should assess the substance of the relevant terms and features (i.e., the relative strength of the debt-like or

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2016 and 2015

equity-like terms and features given the facts and circumstances) when considering how to weight those terms and features. The adoption of this ASU on January 1, 2016 did not have an impact on our unaudited consolidated financial statements.

Debt Issuance Costs. In April 2015, the FASB issued ASU 2015-03-Interest-Imputation of Interest (Subtopic 835-30). The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for our 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.

We adopted these ASUs on January 1, 2016 on a retrospective basis affecting presentation on the unaudited consolidated balance sheets for all periods presented.

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 adoption of this ASU on January 1, 2016 did not have an 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. The adoption of this ASU on January 1, 2016 did not have an impact on our unaudited consolidated financial statements.

Accounting Standards Not Yet Adopted

Compensation. In March 2016, the FASB issued ASU 2016-09-Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The amendments in this ASU simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, with early adoption permitted. We are currently evaluating this ASU and any potential impacts the adoption of this ASU will have on our unaudited consolidated financial statements.

Debt Instruments. In March 2016, the FASB issued ASU 2016-06-Derivative and Hedging: Contingent Put and Call Options in Debt Instruments. The amendments in this ASU clarify what steps are required when assessing whether the economic characteristics and risks of call (put) options are clearly and closely related to the economic characteristics and risks of their debt hosts, which is one of the criteria for bifurcating an embedded derivative. An entity performing the assessment under the amendments in this ASU is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The amendments are effective for public business entities for fiscal years beginning after December 15, 2016 and interim periods within those fiscal years. All entities have the option of adopting the new requirements early, including adoption in an interim period. If an entity early adopts the new requirements in an interim period, it must reflect any adjustments as of the beginning of the fiscal year that includes that interim period. 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.

Leases. In February 2016, the FASB issued ASU 2016-02-Leases (Topic 842). The amendments in this ASU will mainly require lessees to recognize lease assets and lease liabilities, for those leases classified as operating leases under GAAP, in their balance sheet. The lease assets recognized in the balance sheet will represent a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. The lease liability recognized in the balance sheet will represent the lessee’s obligation to make lease payments arising from a lease, measured on a discounted basis. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019, with early adoption permitted. We are currently evaluating this ASU and any potential impacts the adoption of this ASU will have on our unaudited consolidated financial statements.

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Revenue from Contracts with Customers. In May 2014, the FASB and International Accounting Standards Board 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 and ASU 2016-08 in March 2016. The amendments in ASU 2015-14 develop a common revenue standard for GAAP and International Financial Reporting Standards 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 amendments in ASU 2016-08 are intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations. 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

Delta Stock Purchase Agreement. On February 24, 2016, Atlas Power Finance, LLC (“Atlas” or the “Purchaser”), a wholly owned subsidiary of Atlas Power, LLC (“Atlas Power” or the “JV”), a newly formed limited liability company that is 65 percent indirectly owned by Dynegy and 35 percent owned by affiliated investment funds of Energy Capital Partners III, LLC (the “ECP Funds”), entered into a Stock Purchase Agreement, as amended (the “Delta Stock Purchase Agreement”) with GDF SUEZ Energy North America, Inc. (“GSENA”) and International Power, S.A. (the “Seller”), indirect subsidiaries of Engie S.A. Pursuant to, and subject to the terms and conditions of, the Delta Stock Purchase Agreement, the Purchaser will purchase from the Seller 100 percent of the issued and outstanding shares of common stock of GSENA, thereby acquiring approximately 8,700 MW in certain power generation facilities located in ERCOT, PJM, and ISO-NE for a base purchase price of approximately $3.3 billion in cash, subject to certain adjustments (the “Delta Transaction”).

The Delta Stock Purchase Agreement includes customary representations, warranties and covenants by the parties. The Delta Transaction is subject to various closing conditions, including (i) expiration of the applicable waiting period, which was received on April 1, 2016, under the Hart-Scott-Rodino Act; (ii) obtaining required approvals from the FERC and the Public Utility Commission of Texas; (iii) no injunction or other orders preventing the consummation of the transactions contemplated under the Delta Stock Purchase Agreement; (iv) the completion of GSENA’s internal reorganization in all material respects in accordance with an exhibit attached to the Delta Stock Purchase Agreement; (v) the continuing accuracy of each party’s representations and warranties and (vi) the satisfaction of other customary conditions. We expect the Delta Transaction to close in the fourth quarter of 2016 after satisfaction or waiver of these closing conditions.

Each party has agreed to indemnify the other for breaches of representations, warranties and covenants, and for certain other matters, subject to certain exceptions and limitations. The Delta Stock Purchase Agreement contains certain termination rights for both the Purchaser and the Seller, including if the closing does not occur within 12 months following the date of the Delta Stock Purchase Agreement. In the event the Delta Stock Purchase Agreement is terminated under certain circumstances, including the failure to obtain certain regulatory approvals, the Purchaser must pay GSENA a reverse termination fee of $132 million.

In connection with the Delta Transaction, each of Dynegy and the ECP Funds entered into equity commitment letters with the JV and the Purchaser, pursuant to which Dynegy and the ECP Funds have agreed to provide up to $1.185 billion ($770 million from Dynegy and $415 million from the ECP Funds) to the JV. Additionally, the JV has secured approximately $2.25 billion of committed debt facilities, including a $400 million junior bridge facility from the ECP funds and $1.85 billion of senior secured debt from a group of banks. These financings are non-recourse to Dynegy. We expect the JV to replace the $1.85 billion senior secured debt with permanent financing prior to the expected closing date of the Delta Transaction.

Also, on February 24, 2016, Dynegy entered into a Stock Purchase Agreement (the “PIPE Stock Purchase Agreement”) with Terawatt Holdings, LP (“Terawatt”), an affiliate of ECP Funds, pursuant to which Dynegy will, subject to the terms and conditions of the PIPE Stock Purchase Agreement, sell and issue to Terawatt at the closing of the Delta Transaction 13,711,152 shares of common stock, $0.01 par value per share, of Dynegy for an aggregate purchase price equal to $150 million (the “PIPE Transaction”). The closing of the PIPE Transaction is contingent on the closing of the Delta Transaction.

In addition, Dynegy has agreed to enter into an Investor Rights Agreement, in the form attached to the PIPE Stock Purchase Agreement (the “Investor Rights Agreement”), with Terawatt at the closing of the PIPE Transaction. Under the Investor Rights Agreement, Terawatt will be entitled to certain rights, including certain registration rights, rights of first refusal with respect to

DYNEGY INC.
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For the Interim Periods Ended March 31, 2016 and 2015

issuances of our common stock and the designation of one individual to serve on our Board of Directors as long as Terawatt and its affiliates own at least 10 percent of our common stock. Further, the Investor Rights Agreement subjects Terawatt to certain obligations, including certain voting obligations and customary standstill and lock-up periods.

Concurrently with the execution of the Delta Stock Purchase Agreement, each of Dynegy and one of the ECP Funds entered into limited guarantees in favor of GSENA to guarantee 65 percent and 35 percent, respectively, of the Purchaser’s obligation to pay the reverse termination fee of $132 million in accordance with the terms and conditions of the Delta Stock Purchase Agreement. Please read Note 13—Commitments and Contingencies for further discussion.

We incurred acquisition costs of $2 million for the three months ended March 31, 2016 related to the Delta Stock Purchase Agreement, which is included in Acquisition and integration costs in our unaudited consolidated statements of operations.

Energy Capital Partners (“ECP”) Purchase Agreements. On April 1, 2015 (the “EquiPower Closing Date”), pursuant to the terms of a stock purchase agreement dated August 21, 2014, as amended, our wholly-owned subsidiary, Dynegy Resource II, LLC purchased 100 percent of the equity interests in EquiPower Resources Corp. (“ERC”) from certain affiliates of ECP (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, our wholly-owned subsidiary Dynegy Resource III, LLC purchased 100 percent of the equity interests in Brayton Point Holdings, LLC (“Brayton”) from certain affiliates of ECP (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.

Duke Midwest Purchase Agreement. On April 2, 2015, 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 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 $2.8 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.

Business Combination Accounting. The EquiPower Acquisition and the Duke Midwest Acquisition (collectively, the “Acquisitions”) have been accounted for in accordance with Accounting Standards Codification (“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 is 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 valuation is still being obtained or reviewed.

Dynegy expects to finalize these amounts during the second quarter of 2016. The significant assets and liabilities for which provisional amounts are recognized at the respective acquisition dates are property, plant and equipment (“PP&E”), goodwill, deferred income taxes and taxes other than deferred income taxes. We continue to evaluate settlements which could relate to pre-acquisition activity from the ISOs. Additionally, some taxes have not yet been finalized with the associated taxing jurisdictions, resulting in a potential change to their fair value at acquisition. These changes may also impact the fair value of the acquired PP&E, goodwill or deferred tax liability. As such, the provisional amounts recognized are subject to revision until our valuation is 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 ("AROs") were recorded in accordance with ASC 410, Asset Retirement and Environmental Obligations. To fair value the acquired PP&E, we used a discounted cash flow ("DCF") analysis based upon a debt-free, free cash flow model. The DCF model was created for each power generation facility based on its remaining useful life, and included gross margin forecasts for each facility using forward commodity market prices obtained from third party quotations for the years 2015 and 2016. For the years 2017 through 2024, we used gross margin forecasts based upon commodity and capacity price curves developed internally using forward New York Mercantile Exchange 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 percent to 10 percent for gas-fired generation facilities and approximately 9 percent 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.

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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:

(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	49	126	175
Inventory	167	105	272
Assets from risk management activities (including current portion of $4 million and $30 million, respectively)	4	33	37
Prepayments and other current assets	32	69	101
Property, plant and equipment	2,773	2,734	5,507
Investment in unconsolidated affiliate	200	—	200
Intangible assets (including current portion of $67 million and $36 million, respectively)	111	84	195
Other long-term assets	28	35	63
Total assets acquired	3,631	3,186	6,817
Accounts payable	27	96	123
Accrued liabilities and other current liabilities	22	10	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	43	49	92
Intangible liabilities (including current portion of $24 million and $58 million, respectively)	73	93	166
Deferred income taxes, net	506	—	506
Other long-term liabilities	—	40	40
Total liabilities assumed	767	395	1,162
Identifiable net assets acquired	2,864	2,791	5,655
Goodwill	797	—	797
Net assets acquired	$ 3,661	$ 2,791	$6,452

We incurred acquisition costs of zero and $90 million for the three months ended March 31, 2016 and 2015, respectively, related to the Acquisitions, which are included in Acquisition and integration costs in our unaudited consolidated statements of operations. Acquisition costs for the three months ended March 31, 2015 included $42 million in acquisition advisory and consulting fees and $48 million in 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 upon our execution of the permanent financing for the Acquisitions. Revenues of $661 million and operating income of $157 million attributable to the Acquisitions for the three months ended March 31, 2016 are included in our unaudited consolidated statements of operations.

Pro Forma Results. The unaudited pro forma financial results for the three months ended March 31, 2015 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.

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(amounts in millions)	Three Months Ended March 31, 2015
Revenues	$1,622
Net income	$80
Net loss attributable to noncontrolling interests	$(1)
Net income attributable to Dynegy Inc.	$81

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. At March 31, 2016 and December 31, 2015, our equity method investment included in our unaudited consolidated balance sheets was $185 million and $190 million, respectively. Upon the acquisition of our Elwood investment, we recognized basis differences in the net assets of approximately $89 million related to working capital, PP&E, 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 sheets.
We recorded $2 million in equity earnings related to our investment in Elwood, which is reflected in Earnings from unconsolidated investments in our unaudited consolidated statement of operations for the three months ended March 31, 2016. For the three months ended March 31, 2016, we received a distribution of $8 million, all of which was considered a return of investment. At March 31, 2016 and December 31, 2015, we have $2 million and $3 million in accounts receivable due from Elwood, respectively, which is included in Accounts receivable in our unaudited consolidated balance sheets.
Note 5—Risk Management Activities, Derivatives, and Financial Instruments
The nature of our business necessarily involves commodity market and financial risks. Specifically, we are exposed to commodity price variability related to our power generation business. Our commercial team manages these commodity price risks with financially and physically settled contracts consistent with our commodity risk management policy. Our treasury team manages our interest rate risk.
Our commodity risk management policy gives us the flexibility to sell energy and capacity and purchase fuel through a combination of spot market sales and near-term contractual arrangements (generally over a rolling one- to three-year time frame). Our commodity risk management goal is to protect cash flow in the near-term while keeping the ability to capture value longer-term.
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, Derivatives and Hedging. 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.

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Quantitative Disclosures Related to Financial Instruments and Derivatives
As of March 31, 2016, we had net purchases and sales of derivative contracts outstanding in the following quantities:

Contract Type	Quantity	Unit of Measure	Fair Value (1)
(dollars and quantities in millions)	Purchases (Sales)		Asset (Liability)
Commodity contracts:			
Electricity derivatives (2)	(50)	MWh	$ 148
Electricity basis derivatives (3)	(7)	MWh	$ 3
Natural gas derivatives (2)	362	MMBtu	$ (168)
Natural gas basis derivatives	83	MMBtu	$ (3)
Diesel fuel	2	Gallon	$ (3)
Coal derivatives (4)	—	Metric Ton	$ (15)
Emissions derivatives	4	Metric Ton	$ (3)
Interest rate swaps	775	U.S. Dollar	$ (46)
Common stock warrants (5)	16	Warrant	$ (6)

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(1) Includes both asset and liability risk management positions, but excludes margin and collateral netting of $79 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.

Derivatives on the Balance Sheet. The following tables present the fair value and balance sheet classification of derivatives in our unaudited consolidated balance sheets as of March 31, 2016 and December 31, 2015. As of March 31, 2016 and December 31, 2015, there were no gross amounts available to be offset that were not offset in our unaudited consolidated balance sheets.

		March 31, 2016			
			Gross amounts offset in the balance sheet		
Contract Type	Location on Balance Sheet	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	$653	$(424)	$ —	$229
Total derivative assets		$653	$(424)	$ —	$229
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(694)	$424	$ 79	$(191)
Interest rate contracts	Liabilities from risk management activities	(46)	—	—	(46)
Common stock warrants	Other long-term liabilities	(6)	—	—	(6)
Total derivative liabilities		$(746)	$424	$ 79	$(243)
Total derivatives		$(93)	$—	$ 79	$(14)

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		December 31, 2015			
			Gross amounts offset in the balance sheet		
Contract Type	Location on Balance Sheet	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	$ 403	$ (285)	$ —	$ 118
Total derivative assets		$ 403	$ (285)	$ —	$ 118
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$ (557)	$ 285	$ 106	$ (166)
Interest rate contracts	Liabilities from risk management activities	(42)	—	—	(42)
Common stock warrants	Other long-term liabilities	(7)	—	—	(7)
Total derivative liabilities		$ (606)	$ 285	$ 106	$ (215)
Total derivatives		$ (203)	$ —	$ 106	$ (97)

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) as of March 31, 2016 is $35 million for which we have posted $21 million in collateral. Our remaining derivative instruments do not have credit-related collateral contingencies as they are included within our first-lien collateral program.

The following table summarizes our cash collateral posted as of March 31, 2016 and December 31, 2015, within Prepayments and other current assets on our unaudited consolidated balance sheets, and the amount applied against short-term risk management activities:

Location on Balance Sheet	March 31, 2016	December 31, 2015
(amounts in millions)		
Gross collateral posted with counterparties	$ 140	$ 162

Less: Collateral netted against risk management liabilities	79	106
Net collateral within Prepayments and other current assets	$ 61	$ 56

Impact of Derivatives on the Unaudited Consolidated Statements of Operations

The following discussion and table 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.

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Our unaudited consolidated statements of operations for the three months ended March 31, 2016 and 2015 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 March 31, 2016	2015
(amounts in millions)			
Commodity contracts	Revenues	$192	$19
Interest rate contracts	Interest expense	$(8)	$(9)
Common stock warrants	Other income and (expense), net	$1	$(5)

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 March 31, 2016 and December 31, 2015 and are presented on a gross basis before consideration of amounts netted under master netting agreements and the application of collateral and margin paid:

	Fair Value as of March 31, 2016			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$515	$47	$562
Natural gas derivatives	—	67	14	81
Emissions derivatives	—	1	—	1
Coal derivatives	—	7	2	9
Total assets from commodity risk management activities	$—	$590	$63	$653
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(347)	$(64)	$(411)
Natural gas derivatives	—	(220)	(32)	(252)
Emissions derivatives	—	(4)	—	(4)
Diesel fuel derivatives	—	(3)	—	(3)
Coal derivatives	—	(23)	(1)	(24)
Total liabilities from commodity risk management activities	—	(597)	(97)	(694)
Liabilities from interest rate contracts	—	(46)	—	(46)
Liabilities from outstanding common stock warrants	(6)	—	—	(6)
Total liabilities	$(6)	$(643)	$(97)	$(746)

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(amounts in millions)	Fair Value as of December 31, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$308	$40	$348
Natural gas derivatives	—	40	2	42
Coal derivatives	—	10	3	13
Total assets from commodity risk management activities	$—	$358	$45	$403
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(267)	$(58)	$(325)
Natural gas derivatives	—	(158)	(34)	(192)
Diesel derivatives	—	(4)	—	(4)
Coal derivatives	—	(35)	(1)	(36)
Total liabilities from commodity risk management activities	—	(464)	(93)	(557)
Liabilities from interest rate contracts	—	(42)	—	(42)
Liabilities from outstanding common stock warrants	(7)	—	—	(7)
Total liabilities	$(7)	$(506)	$(93)	$(606)

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, 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 March 31, 2016 are as follows:

Transaction Type	Quantity	Unit of Measure	Net Fair Value	Valuation Technique	Significant Unobservable Input	Significant Unobservable Input Range
(dollars in millions)						
Electricity derivatives:						

Forward contracts—power (1)	(4)	Million MWh	$ (12)	Basis spread + liquid location	Basis spread	$5.00 - $7.00
FTRs	15	Million MWh	$ (5)	Historical congestion	Forward price	$0 - $9.00
Natural gas derivatives (1)	75	Million MMBtu	$ (18)	Illiquid location fixed price	Forward price	$1.20 - $1.50
Coal derivatives (1)	—	Thousand Tons	$ 1	Illiquid location fixed price	Forward price	$4.20 - $5.10

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

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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 March 31, 2016			
(amounts in millions)	Electricity Derivatives	Natural Gas Derivatives	Coal Derivatives	Total
Balance at December 31, 2015	$(18)	$ (32)	$ 2	$(48)
Total gains included in earnings	8	5	—	13
Settlements (1)	(7)	9	(1)	1
Balance at March 31, 2016	$(17)	$ (18)	$ 1	$(34)
Unrealized gains relating to instruments held as of March 31, 2016	$8	$ 5	$ —	$13

	Three Months Ended March 31, 2015			
(amounts in millions)	Electricity Derivatives	Natural Gas Derivatives	Coal Derivatives	Total
Balance at December 31, 2014	$(4)	$ —	$ —	$(4)
Total gains included in earnings	3	—	—	3
Settlements (1)	5	—	—	5
Balance at March 31, 2015	$4	$ —	$ —	$4
Unrealized gains relating to instruments held as of March 31, 2015	$3	$ —	$ —	$3

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(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 months ended March 31, 2016 and 2015.

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 months ended March 31, 2016 and 2015, other than the provisional purchase price allocation discussed in Note 3—Acquisitions.

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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 March 31, 2016 and December 31, 2015, respectively.

	March 31, 2016		December 31, 2015	
(amounts in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Dynegy Inc.:				
6.75% Senior Notes, due 2019 (1)(7)	$(2,078)	$(2,090)	$(2,077)	$(1,985)
Tranche B-2 Term Loan, due 2020 (1)(2)	$(765)	$(766)	$(766)	$(754)
7.375% Senior Notes, due 2022 (1)(7)	$(1,729)	$(1,628)	$(1,729)	$(1,531)
5.875% Senior Notes, due 2023 (1)(7)	$(492)	$(423)	$(491)	$(404)
7.625% Senior Notes, due 2024 (1)(7)	$(1,235)	$(1,131)	$(1,235)	$(1,078)
Forward capacity agreement (3)(8)	$(198)	$(198)	$—	$—
Inventory financing agreements (8)	$(134)	$(134)	$(136)	$(136)
Equipment financing agreements (4)(8)	$(62)	$(62)	$(61)	$(61)
Interest rate derivatives (1)	$(46)	$(46)	$(42)	$(42)
Commodity-based derivative contracts (5)	$(41)	$(41)	$(154)	$(154)
Common stock warrants (6)	$(6)	$(6)	$(7)	$(7)
Genco:				
7.00% Senior Notes Series H, due 2018 (1)(9)	$(279)	$(120)	$(276)	$(204)
6.30% Senior Notes Series I, due 2020 (1)(9)	$(215)	$(85)	$(213)	$(148)
7.95% Senior Notes Series F, due 2032 (1)(9)	$(225)	$(88)	$(225)	$(162)

(1) The fair values of these financial instruments are classified as Level 2 within the fair value hierarchy levels.
(2) Carrying amount includes an unamortized discount and debt issuance costs of $13 million and $14 million as of March 31, 2016 and December 31, 2015, respectively. Please read Note 12—Debt for further discussion.
(3) Carrying amount includes an unamortized discount of $21 million as of March 31, 2016.
(4) Carrying amounts for the equipment financing agreement include unamortized discounts of $14 million and $14 million as of March 31, 2016 and December 31, 2015, respectively.
(5) Carrying amount of commodity-based derivative contracts excludes $79 million and $106 million of cash posted as collateral, as of March 31, 2016 and December 31, 2015, respectively.
(6) The fair value of the common stock warrants is classified as Level 1 within the fair value hierarchy levels.
(7) Combined carrying amounts include debt issuance costs of $66 million and $68 million as of March 31, 2016 and December 31, 2015, respectively.
(8) The fair values of these financial instruments are classified as Level 3 within the fair value hierarchy levels and are based on internal estimates.
(9) Combined carrying amounts include unamortized discounts and debt issuance costs of $106 million and $111 million as of March 31, 2016 and December 31, 2015, respectively. Please read Note 12—Debt for further discussion.

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Note 7—Accumulated Other Comprehensive Income

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

(amounts in millions)	Three Months Ended March 31, 2016	2015
Beginning of period	$19	$20
Amounts reclassified from accumulated other comprehensive income:		
Amortization of unrecognized prior service credit and actuarial gain (net of tax of zero and zero, respectively) (1)	(1)	(1)
Net current period other comprehensive loss, net of tax	(1)	(1)
End of period	$18	$19

(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 15—Pension and Other Post-Employment Benefit Plans for further discussion.

Note 8—Inventory

A summary of our inventories is as follows:

(amounts in millions)	March 31, 2016	December 31, 2015
Materials and supplies	$ 176	$ 175
Coal (1)	344	350
Fuel oil (1)	17	17
Emissions allowances (2)	39	51
Other	3	4
Total	$ 579	$ 597

(1) At March 31, 2016, approximately $46 million and $12 million of the coal and fuel oil inventory, respectively, are part of an inventory financing agreement. At December 31, 2015, approximately $44 million and $16 million of the coal and fuel oil inventory, respectively, were part of an inventory financing agreement. Please read Note 12—Debt—Brayton Point Inventory Financing for further discussion.

(2) At March 31, 2016 and December 31, 2015, a portion of this inventory was held as collateral by one of our counterparties as part of an inventory financing agreement. Please read Note 12—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)	March 31, 2016	December 31, 2015
Power generation	$ 8,240	$ 8,178
Buildings and improvements	958	956
Office and other equipment	103	101
Property, plant and equipment	9,301	9,235
Accumulated depreciation	(1,059)	(888)
Property, plant and equipment, net	$ 8,242	$ 8,347

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,

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fuel inventory purchases, and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to 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 tables present the ownership interests of the jointly owned facilities as of March 31, 2016 and December 31, 2015 included in our unaudited consolidated balance sheets. Each facility is co-owned with one or more other generation companies.

	March 31, 2016				
(dollars in millions)	Ownership Interest	Property, Plant and Equipment	Accumulated Depreciation	Construction Work in Progress	Total
Miami Fort	64.0%	$ 205	$ (22)	$ 3	$186
Stuart (1)	39.0%	$ 32	$ (5)	$ 23	$50
Conesville (1)	40.0%	$ 60	$ (1)	$ 4	$63
Zimmer	46.5%	$ 99	$ (11)	$ 10	$98
Killen (1)	33.0%	$ 17	$ (1)	$ 2	$18

	December 31, 2015				
(dollars in millions)	Ownership Interest	Property, Plant and Equipment	Accumulated Depreciation	Construction Work in Progress	Total
Miami Fort	64.0%	$ 207	$ (16)	$ 3	$194
Stuart (1)	39.0%	$ 32	$ (4)	$ 20	$48
Conesville (1)	40.0%	$ 61	$ (2)	$ 4	$63
Zimmer	46.5%	$ 99	$ (10)	$ 11	$100
Killen (1)	33.0%	$ 17	$ (1)	$ 2	$18

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(1) Facilities not operated by Dynegy.

Note 11—Intangible Assets and Liabilities

The following table summarizes the components of our intangible assets and liabilities as of March 31, 2016 and December 31, 2015:

	March 31, 2016			December 31, 2015		
(amounts in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Intangible Assets:						
Electricity contracts	$260	$ (148)	$ 112	$260	$ (126)	$ 134
Gas transport contracts	46	(33)	13	46	(16)	30
Total intangible assets	$306	$ (181)	$ 125	$306	$ (142)	$ 164
Intangible Liabilities:						
Electricity contracts	$(30)	$ 25	$ (5)	$(30)	$ 19	$ (11)
Coal contracts	(116)	76	(40)	(134)	82	(52)
Coal transport contracts	(104)	71	(33)	(104)	64	(40)
Gas transport contracts	(41)	4	(37)	(64)	27	(37)
Total intangible liabilities	$(291)	$ 176	$ (115)	$(332)	$ 192	$ (140)

Intangible assets and liabilities, net	$15	$ (5)	$ 10	$(26)	$ 50	$ 24

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The following table presents our amortization expense (revenue) of intangible assets and liabilities for the three months ended March 31, 2016 and 2015:

(amounts in millions)	Three Months Ended March 31, 2016	2015
Electricity contracts, net (1)	$ 16	$ 7
Coal contracts, net (2)	(12)	(3)
Coal transport contracts, net (2)	(7)	(6)
Gas transport contracts, net (2)	17	(2)
Total	$ 14	$ (4)

(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.

Note 12—Debt

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

(amounts in millions)	March 31, 2016	December 31, 2015
Dynegy Inc.:		
6.75% Senior Notes, due 2019	$ 2,100	$ 2,100
Tranche B-2 Term Loan, due 2020	778	780
7.375% Senior Notes, due 2022	1,750	1,750
5.875% Senior Notes, due 2023	500	500
7.625% Senior Notes, due 2024	1,250	1,250
Forward Capacity Agreement	219	—
Inventory Financing Agreements	134	136
Equipment Financing Agreements	76	75
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
	7,632	7,416
Unamortized debt discounts and issuance costs (1)	(220)	(207)
	7,412	7,209
Less: Current maturities, including unamortized debt discounts and issuance costs, net	108	80
Total Long-term debt	$ 7,304	$ 7,129

(1) Includes $80 million related to the reclassification of unamortized debt issuance costs as of December 31, 2015. Please read Note 2—Accounting Policies for further discussion.

Senior Notes

As of March 31, 2016, we had $5.6 billion in senior notes that consisted of (i) $2.1 billion 6.75 percent senior notes, due 2019, (ii) $1.75 billion 7.375 percent senior notes, due 2022, (iii) $500 million 5.875 percent senior notes, due 2023, and (iv) $1.25 billion 7.625 percent senior notes, due 2024 (collectively, the “Senior Notes”).

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Credit Agreement

As of March 31, 2016, we had a $2.225 billion credit agreement, as amended, that consisted of (i) an $800 million seven-year senior secured term loan B facility (the “Tranche B-2 Term Loan”) and (ii) $1.425 billion in senior secured revolving credit facilities (the “Revolving Facility,” and collectively with the Tranche B-2 Term Loan, the “Credit Agreement”). The Revolving Facility includes three incremental tranches of revolving commitments consisting of: (i) a $475 million tranche which will mature on April 23, 2018, (ii) a $350 million tranche which will mature April 1, 2020, and (iii) a $600 million tranche which will mature on April 2, 2020.

At March 31, 2016, there were no amounts drawn on the Revolving Facility; however, we had outstanding letters of credit (“LCs”) of approximately $441 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 are in compliance as of March 31, 2016.

Genco Senior Notes

Genco’s approximately $825 million in aggregate principal amount of unsecured senior notes (the “Genco Senior Notes”) are an obligation of Genco, a subsidiary of IPH. The Genco Senior Notes are non-recourse to Dynegy.

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. 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.

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%

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(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 external, third-party sources are included in the definition of indebtedness and are subject to these incurrence tests.

Based on March 31, 2016 calculations, Genco did not meet the ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources.

Letter of Credit Facilities

On January 29, 2014, Illinois Power Marketing Company (“IPM”) entered into a fully cash collateralized LC 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 LCs 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 LC plus an additional percentage thereon. As of March 31, 2016, IPM had $14 million deposited with the issuing bank and $13 million in LCs outstanding.

On September 18, 2014, Dynegy entered into an LC Reimbursement Agreement with an issuing bank, and its affiliate (the “Lender”), for an LC in an amount not to exceed $55 million. The facility expires in September 2016. At March 31, 2016, there was $55 million outstanding under this LC.

On March 27, 2015, IPM entered into an LC facility with the Lender for up to $25 million. The facility, which is collateralized by Illinois Power Resources Generating, LLC ("IPRG") 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 LCs. At March 31, 2016, there was $22 million outstanding under this LC facility.

Forward Capacity Agreement

On March 18, 2016, we entered into a bilateral contract with a financial institution to sell a portion of our forward cleared PJM capacity auction volumes. In exchange, we received $198 million in cash proceeds during the first quarter of 2016. The buyer in this transaction will receive capacity payments from PJM during the Planning Years 2017-2018 and 2018-2019 in the amounts of $110 million and $109 million, respectively. Dynegy will continue to be subject to the performance obligations as well as any associated performance penalties and bonus payments for those planning years. The transaction is accounted for as a debt issuance of $219 million with an implied interest rate of 4.45 percent.

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 in excess of the $15 million line of credit are cash collateralized. The Inventory Financing Agreement terminates, and any remaining obligation becomes due and payable, on May 31, 2017. As of March 31, 2016, there was $56 million outstanding under this agreement. Additionally, we had collateral postings of approximately $12 million.

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 costs, and other expenses. The debt obligation increases for 85 percent of the total cost of the coal and for 90 percent of the total cost of the fuel oil. The line of credit increases for the remaining 15 percent and 10 percent for coal and oil costs, 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.

As of March 31, 2016, both the debt obligation related to coal and the base level of fuel oil, as well as the line of credit, bear interest at an annual interest rate of the 3-month LIBOR plus 5.6 percent. An availability fee is calculated on a per annum rate of 0.75 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 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. As of March 31, 2016, there was $78 million, in aggregate, outstanding under these agreements.

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. The portion of future payments attributable to principal will be classified as cash outflows from financing activities, and the portion of future payments attributable to interest will be classified as cash outflows from operating activities in our unaudited consolidated statements of cash flows. As of March 31, 2016, there was $76 million outstanding under these agreements. The related assets were recorded at the net present value of the payments of $62 million. The $14 million discount is currently amortized as interest expense over the life of the payments.

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 $775 million at an average fixed rate of 3.19 percent with a floor of one percent, and expire during the second quarter of 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 statements of cash flows.

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Note 13—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, the 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.

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.

Gas Index Pricing Litigation. We, through our subsidiaries, and other energy companies are named as defendants in several lawsuits claiming damages resulting from alleged price manipulation and false reporting of natural gas prices to various index publications from 2000-2002. The cases allege that the defendants engaged in an antitrust conspiracy to inflate natural gas prices in three states (Kansas, Missouri, and Wisconsin) during the relevant time period. The cases are consolidated in a multi-district litigation proceeding pending in the United States District Court for Nevada. 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. On May 23, 2014, the Texas Supreme Court vacated the arbitration award based upon the evident partiality of one of the arbitrators. 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 IGC's $17 million payment remains pending. On December 16, 2014, the Dallas District Court entered a judgment requiring the return of the $17 million to IGC and an additional $2.5 million payment to IGC for interest. PPE paid the $17 million principal to IGC (not the $2.5 million in interest), but simultaneously appealed the judgment, which remains pending in the Dallas Court of Appeals.

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. We filed our Answer to these complaints and believe that we complied fully with the terms of the MISO tariff in connection with the 2015-2016 PRA, disputed the allegations, and will defend our actions vigorously. 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.

On December 31, 2015, FERC issued an order on the complaints requiring a number of prospective changes to the MISO tariff provisions associated with calculating Initial Reference Levels and Local Clearing Requirements, effective as of the 2016-2017 PRA. Under the order, FERC found that the existing tariff provision which bases Initial Reference Levels for capacity supply offers on the estimated opportunity cost of exporting capacity to a neighboring region (for example, PJM) are no longer just and reasonable. Accordingly, FERC required MISO to set the Initial Reference Level for capacity at $0 per MW-day for the 2016-2017 PRA. Capacity suppliers may also request a facility-specific reference level from the MISO IMM. The order did not address the arguments of the complainants regarding the 2015-2016 PRA, and stated that those issues remain under consideration and will be addressed in a future order.

New Source Review and CAA Matters.

New Source Review. 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.

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. If not overturned, this decision may provide an additional defense to the allegations in the Newton facility NOV.

Wood River CAA Section 114 Information Request. In 2014, we received an information request from the EPA concerning our 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. We plan to retire our Wood River facility on June 1, 2016, as approved by MISO.

CAA Notices of Violation. In December 2014, the EPA issued an NOV alleging violation of opacity standards at the Zimmer facility, which we co-own and operate. 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, sulfur dioxide, 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 Stuart and Killen facilities, which we co-own but do not operate.

Edwards CAA Citizen Suit. 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 October 2016. We dispute the allegations and will defend the case vigorously.

Ultimate resolution of any of these CAA matters could have a material adverse impact on IPH's future financial condition, results of operations, and cash flows. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses, and penalties. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve these matters.

Stuart NPDES Permit Appeal. In January 2013, the Ohio EPA reissued the National Pollutant Discharge Elimination System ("NPDES") permit for the co-owned Stuart facility. The operator of Stuart, The Dayton Power and Light Company, appealed various aspects of the 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.
Coal Segment Groundwater. In 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities.
At Baldwin, with approval of the Illinois EPA, we performed a comprehensive evaluation of the Baldwin Coal Combustion Residuals ("CCR") surface impoundment system beginning in 2013. Based on the results of that evaluation, we recommended to the Illinois EPA in 2014 that the closure process for the inactive east CCR surface impoundment begin and that a geotechnical investigation of the existing soil cap on the inactive old east CCR surface impoundment be undertaken. We also submitted a supplemental groundwater modeling report that indicates no known offsite water supply wells will be impacted under the various Baldwin CCR surface impoundment closure scenarios modeled. In April 2016, we submitted closure and post-closure care plans

to the Illinois EPA for the Baldwin old east, east, and west fly ash CCR surface impoundments. We await Illinois EPA action on our plans.

We initiated an investigation at Baldwin in 2011 at the request of the Illinois EPA to determine if the facility's CCR surface impoundment system impacts offsite groundwater. Results of the offsite groundwater quality investigation, as submitted to the Illinois EPA in 2012, indicate two localized areas where Class I groundwater standards were exceeded. Based on the data and groundwater flows, we do not believe that the exceedances are attributable to the Baldwin CCR surface impoundment system.

At our retired Vermilion facility, which is not subject to the CCR rule, we submitted proposed corrective action plans for two CCR surface impoundments (i.e., the old east and the north CCR surface impoundments) to the Illinois EPA in 2012. Our hydrogeologic investigation indicates that these two 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 recommend closure in place of both CCR surface impoundments and include an application to the Illinois EPA to establish a groundwater management zone while impacts from the facility are mitigated. In 2014, we submitted a revised corrective action plan for the old east CCR surface impoundment. We await Illinois EPA action on our proposed corrective action plans. In June 2015, we advised the Illinois EPA that the additional analyses requested by the Agency would be performed upon receipt of a riverbank stabilization permit from the U.S. Army Corps of Engineers. 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.

If remediation measures concerning groundwater are necessary in the future at either Baldwin or Vermilion, 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 remediation, if any, that ultimately may be required.

IPH Segment Groundwater. 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 alleging violations of groundwater standards at the Newton and Coffeen facilities' CCR surface impoundments. 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.

If remediation measures concerning groundwater are necessary at any of our IPH facilities, IPH may incur significant costs that could have a material adverse effect on its financial condition, results of operations, and cash flows. At this time we cannot reasonably estimate the costs, or range of costs, of remediation, if any, that ultimately may be required.

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 CCR surface impoundments in 2009. 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 AROs. We performed further studies needed to support closure of the west CCR surface impoundment, submitted those studies to the Illinois EPA in 2014, and await Illinois EPA action.

In response to the Baldwin report, we notified the EPA in 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 evaluation at Baldwin of groundwater corrective actions. At this time, to resolve the concerns raised in the EPA's assessment report and as a result of the CCR rule, we plan to initiate closure of the Baldwin west fly ash CCR surface impoundment in 2017, which is reflected in our AROs.

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, and power generation assets.

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. We have accrued no amounts with respect to the indemnifications as of March 31, 2016 because none were probable of occurring, nor could they be reasonably estimated.

Delta Transaction Guarantees. Concurrently with the execution of the Delta Transaction, each of Dynegy and one of the ECP Funds entered into limited guarantees in favor of GSENA to guarantee 65 percent and 35 percent, respectively, of the Purchaser's obligation to pay the reverse termination fee of $132 million in accordance with the terms and conditions of the Delta Transaction.

Note 14—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. Our Income tax expense for the three months ended March 31, 2016 includes a $15 million charge to deferred state income tax expense as a result of a change to our corporate tax structure in 2016.

As of March 31, 2016, 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.

Note 15—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 further described in Note 18—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans in our Form 10-K.

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

	Pension Benefits		Other Benefits	
	Three Months Ended March 31,			
(amounts in millions)	2016	2015	2016	2015
Service cost benefits earned during period	$4	$ 3	$—	$—
Interest cost on projected benefit obligation	5	4	1	1
Expected return on plan assets	(6)	(5)	(1)	(1)
Amortization of prior service credit	—	—	(1)	(1)
Net periodic benefit cost (gain)	$3	$ 2	$(1)	$(1)

Note 16—Capital Stock

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 three months ended March 31, 2016 and 2015, we paid an aggregate of $5 million and $7 million in dividends on February 1, 2016 and February 2, 2015, respectively.

On April 1, 2016, 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 February 1, 2016 and ending on April 30, 2016. Such dividends were paid on May 2, 2016 to stockholders of record as of April 15, 2016.

Note 17—Loss Per Share

The basic and diluted loss per share from continuing operations attributable to our common stockholders during the three months ended March 31, 2016 and 2015 is shown in the following table. Please read Note 15—Capital Stock in our Form 10-K for further discussion.

	Three Months Ended March 31,	
(in millions, except per share amounts)	2016	2015
Loss from continuing operations	$(10)	$(181)
Less: Net loss attributable to noncontrolling interest	—	(1)
Loss from continuing operations attributable to Dynegy Inc.	(10)	(180)
Less: Dividends on preferred stock	5	5
Loss from continuing operations attributable to Dynegy Inc. common stockholders for basic and diluted loss per share	(15)	(185)
Basic and diluted weighted-average shares (1)	117	124
Basic and diluted loss per share from continuing operations attributable to Dynegy Inc. common stockholders (1)	$(0.13)	$(1.49)

(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 used the basic shares outstanding amount to calculate both basic and diluted loss per share for the three months ended March 31, 2016 and 2015.

For the three months ended March 31, 2016 and 2015, 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 March 31,	
(in millions of shares)	2016	2015
Stock options	2.8	1.8
Restricted stock units	1.3	1.2
Performance stock units	1.2	0.6
Warrants	15.6	15.6
Series A 5.375% mandatory convertible preferred stock	12.9	12.9
Total	33.8	32.1

Note 18—Condensed Consolidating Financial Information

The following condensed consolidating financial statements present the financial information of (i) Dynegy (“Parent”), which is the parent and issuer of the $5.6 billion Senior 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. The 100 percent owned subsidiary guarantors, jointly, severally, fully, and unconditionally, guarantee the payment obligations under the Senior Notes. Not all of Dynegy’s subsidiaries guarantee the Senior Notes including Dynegy’s indirect, wholly-owned subsidiary, IPH. Dynegy Finance I, Inc. and Dynegy Finance II, Inc (the “Escrow Issuers”) were merged with Parent effective April 2015. Please read Note 13—Debt in our Form 10-K for further discussion

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 unaudited condensed consolidating financial statements, a portion of our intercompany receivable, which we do not consider to be likely of settlement, has been classified as equity as of March 31, 2016 and December 31, 2015.

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Condensed Consolidating Balance Sheet as of March 31, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$639	$ 80	$ 102	$ —	$ 821
Restricted cash	—	—	37	—	37
Accounts receivable, net	539	1,329	115	(1,644)	339
Inventory	—	309	270	—	579
Other current assets	14	454	47	(10)	505
Total Current Assets	1,192	2,172	571	(1,654)	2,281
Property, plant and equipment, net	—	7,722	520	—	8,242
Investment in affiliates	12,665	185	—	(12,665)	185
Goodwill	—	797	—	—	797
Other assets	8	147	48	—	203
Intercompany note receivable	17	—	—	(17)	—
Total Assets	$13,882	$ 11,023	$ 1,139	$ (14,336)	$ 11,708
Current Liabilities					
Accounts payable	$1,291	$ 202	$ 394	$ (1,644)	$ 243
Other current liabilities	193	291	146	(10)	620
Total Current Liabilities	1,484	493	540	(1,654)	863
Debt, long-term portion	6,294	291	719	—	7,304
Intercompany note payable	3,042	—	17	(3,059)	—
Other liabilities	153	342	139	—	634
Total Liabilities	10,973	1,126	1,415	(4,713)	8,801
Stockholders’ Equity					
Dynegy Stockholders’ Equity	2,909	12,939	(274)	(12,665)	2,909
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders’ Equity	2,909	9,897	(274)	(9,623)	2,909
Noncontrolling interest	—	—	(2)	—	(2)
Total Equity	2,909	9,897	(276)	(9,623)	2,907
Total Liabilities and Equity	$13,882	$ 11,023	$ 1,139	$ (14,336)	$ 11,708

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Condensed Consolidating Balance Sheet as of December 31, 2015
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$327	$ 94	$ 84	$ —	$ 505
Restricted cash	—	—	39	—	39
Accounts receivable, net	499	1,503	130	(1,730)	402
Inventory	—	331	266	—	597
Other current assets	13	335	55	(14)	389
Total Current Assets	839	2,263	574	(1,744)	1,932
Property, plant and equipment, net	—	7,813	534	—	8,347
Investment in affiliates	13,017	190	—	(13,017)	190
Other long-term assets	10	133	50	—	193
Goodwill	—	797	—	—	797
Intercompany note receivable	17	—	—	(17)	—
Total Assets	$13,883	$ 11,196	$ 1,158	$ (14,778)	$ 11,459
Current Liabilities					
Accounts payable	$1,388	$ 238	$ 396	$ (1,730)	$ 292
Other current liabilities	92	277	162	(14)	517
Total Current Liabilities	1,480	515	558	(1,744)	809
Long-term debt	6,293	122	714	—	7,129
Intercompany note payable	3,042	—	17	(3,059)	—
Other long-term liabilities	147	317	138	—	602
Total Liabilities	10,962	954	1,427	(4,803)	8,540
Stockholders' Equity					
Dynegy Stockholders' Equity	2,921	13,284	(267)	(13,017)	2,921
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	2,921	10,242	(267)	(9,975)	2,921
Noncontrolling interest	—	—	(2)	—	(2)
Total Equity	2,921	10,242	(269)	(9,975)	2,919
Total Liabilities and Equity	$13,883	$ 11,196	$ 1,158	$ (14,778)	$ 11,459

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2016 and 2015

Condensed Consolidating Statements of Operations for the Three Months Ended March 31, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 887	$ 236	$ —	$ 1,123
Cost of sales, excluding depreciation expense	—	(412)	(133)	—	(545)
Gross margin	—	475	103	—	578
Operating and maintenance expense	—	(159)	(62)	—	(221)
Depreciation expense	—	(146)	(25)	—	(171)
General and administrative expense	(2)	(28)	(7)	—	(37)
Acquisition and integration costs	(3)	(1)	—	—	(4)
Operating income (loss)	(5)	141	9	—	145
Earnings from unconsolidated investments	—	2	—	—	2
Equity in earnings from investments in affiliates	118	—	—	(118)	—
Interest expense	(124)	(1)	(17)	—	(142)
Other income and expense, net	1	—	—	—	1
Income (loss) before income taxes	(10)	142	(8)	(118)	6
Income tax expense	—	(16)	—	—	(16)
Net income (loss)	(10)	126	(8)	(118)	(10)
Less: Net income attributable to noncontrolling interest	—	—	—	—	—
Net income (loss) attributable to Dynegy Inc.	$(10)	$ 126	$ (8)	$ (118)	$ (10)

Condensed Consolidating Statements of Operations for the Three Months Ended March 31, 2015
(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ —	$ 413	$ 219	$ —	$ 632
Cost of sales, excluding depreciation expense	—	—	(239)	(138)	—	(377)
Gross margin	—	—	174	81	—	255
Operating and maintenance expense	—	—	(60)	(51)	—	(111)
Depreciation expense	—	—	(56)	(8)	—	(64)
General and administrative expense	(1)	—	(17)	(12)	—	(30)
Acquisition and integration costs	—	—	—	(90)	—	(90)
Operating income (loss)	(1)	—	41	(80)	—	(40)
Equity in losses from investments in affiliates	(147)	—	—	—	147	—
Interest expense	(27)	(93)	—	(16)	—	(136)
Other income and expense, net	(5)	—	—	—	—	(5)
Income (loss) before income taxes	(180)	(93)	41	(96)	147	(181)
Income tax expense	—	—	—	—	—	—
Net income (loss)	(180)	(93)	41	(96)	147	(181)
Less: Net loss attributable to noncontrolling interest	—	—	—	(1)	—	(1)
Net income (loss) attributable to Dynegy Inc.	$(180)	$ (93)	$ 41	$ (95)	$ 147	$ (180)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2016 and 2015

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended March 31, 2016

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$(10)	$ 126	$ (8)	$ (118)	$ (10)
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)	(11)	126	(8)	(118)	(11)
Less: Comprehensive loss attributable to noncontrolling interest	—	—	—	—	—
Total comprehensive income (loss) attributable to Dynegy Inc.	$(11)	$ 126	$ (8)	$ (118)	$ (11)

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended March 31, 2015

(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$(180)	$(93)	$ 41	$ (96)	$ 147	$ (181)
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)	(181)	(93)	41	(96)	147	(182)
Less: Comprehensive loss attributable to noncontrolling interest	—	—	—	(1)	—	(1)
Total comprehensive income (loss) attributable to Dynegy Inc.	$(181)	$(93)	$ 41	$ (95)	$ 147	$ (181)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2016 and 2015

Condensed Consolidating Statements of Cash Flow for the Three Months Ended March 31, 2016

(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$(10)	$ 175	$ 26	$ —	$ 191
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	(4)	(50)	(11)	—	(65)
Net intercompany transfers	339	—	—	(339)	—
Distributions from unconsolidated affiliates	—	8	—	—	8
Net cash provided by (used in) investing activities	335	(42)	(11)	(339)	(57)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowing on long term debt	—	198	—	—	198
Repayments of borrowings	(2)	(3)	—	—	(5)
Dividends paid	(5)	—	—	—	(5)
Net intercompany transfers	—	(342)	3	339	—
Interest rate swap settlement payments	(4)	—	—	—	(4)
Other financing	(2)	—	—	—	(2)
Net cash provided by (used in) financing activities	(13)	(147)	3	339	182
Net increase (decrease) in cash and cash equivalents	312	(14)	18	—	316
Cash and cash equivalents, beginning of period	327	94	84	—	505
Cash and cash equivalents, end of period	$639	$ 80	$ 102	$ —	$ 821

Condensed Consolidating Statements of Cash Flow for the Three Months Ended March 31, 2015

(amounts in millions)

	Parent	Escrow Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:						
Net cash provided by (used in) operating activities	$2	$ (94)	$ 46	$ (9)	$ —	$ (55)
CASH FLOWS FROM INVESTING ACTIVITIES:						
Capital expenditures	—	—	(29)	(11)	—	(40)
Net intercompany transfers	(188)	—	—	—	188	—
Net cash provided by (used in) investing activities	(188)	—	(29)	(11)	188	(40)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Repayment of borrowings	(2)	—	(23)	—	—	(25)
Dividends paid	(7)	—	—	—	—	(7)
Net intercompany transfers	—	94	74	20	(188)	—
Interest rate swap settlement payments	(4)	—	—	—	—	(4)
Other financing	(5)	—	—	—	—	(5)
	(18)	94	51	20	(188)	(41)

Net cash provided by (used in) financing activities						
Net increase (decrease) in cash and cash equivalents	(204)	—	68	—	—	(136)
Cash and cash equivalents, beginning of period	1,642	—	54	174	—	1,870
Cash and cash equivalents, end of period	$1,438	$ —	$ 122	$ 174	$ —	$ 1,734

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DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2016 and 2015

Note 19—Segment Information

We report the results of our operations in three segments: (i) Coal, (ii) IPH, and (iii) Gas. The Coal segment includes certain of our coal-fired power generation facilities and our Dynegy Energy Services retail business. The IPH segment includes Genco, and 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 months ended March 31, 2016 and 2015 is presented below:

Segment Data as of and for the Three Months Ended March 31, 2016

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$393	$168	$562	$ —	$1,123
Intercompany revenues	(13)	(1)	14	—	—
Total revenues	$380	$167	$576	$ —	$1,123
Depreciation expense	$(39)	$(9)	$(122)	$ (1)	$(171)
General and administrative expense	—	—	—	(37)	(37)
Acquisition and integration costs	—	—	—	(4)	(4)
Operating income (loss)	$54	$14	$120	$ (43)	$145
Earnings from unconsolidated investments	—	—	2	—	2
Interest expense	(1)	(17)	(1)	(123)	(142)
Other income and expense, net	—	—	—	1	1
Income before income taxes					6
Income tax expense	—	—	—	(16)	(16)
Net loss					(10)
Less: Net loss attributable to noncontrolling interest					—
Net loss attributable to Dynegy Inc.					$(10)
Total assets—domestic	$2,269	$898	$7,815	$ 726	$11,708
Investment in unconsolidated affiliate	$—	$—	$185	$ —	$185
Capital expenditures	$(19)	$(11)	$(31)	$ (4)	$(65)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2016 and 2015

Segment Data as of and for the Three Months Ended March 31, 2015

(amounts in millions)	Coal	IPH	Gas	Other and Eliminations	Total
Domestic:					
Unaffiliated revenues	$154	$219	$259	$ —	$632
Intercompany revenues	(12)	—	12	—	—
Total revenues	$142	$219	$271	$ —	$632
Depreciation expense	$(10)	$(8)	$(45)	$ (1)	$(64)
General and administrative expense	—	—	—	(30)	(30)
Operating income (loss)	$7	$22	$52	$ (121)	$(40)
Interest expense	—	—	—	(136)	(136)
Other income and expense, net	—	—	—	(5)	(5)
Loss before income taxes					(181)
Income tax expense	—	—	—	—	—
Net loss					(181)
Less: Net loss attributable to noncontrolling interest					(1)
Net loss attributable to Dynegy Inc.					$(180)
Total assets—domestic	$1,162	$1,037	$2,105	$ 6,827	$11,131
Capital expenditures	$(3)	$(11)	$(24)	$ (2)	$(40)

Note 20—Subsequent Event

On May 3, 2016, Dynegy announced the shutdown of two of the three units at its Baldwin power generation facility in Baldwin, Illinois and one of the two units at its Newton power generation facility in Newton, Illinois. Subject to the approval of MISO, we expect to shut down the units over the next year. This decision was made after the units failed to recover their basic operating costs in the most recent MISO auction. Factors influencing these actions included a low power pricing environment, a lack of capacity revenue, and significant maintenance and environmental expenditures required to appropriately maintain the facilities. We will assess the carrying value of our entire MISO fleet for impairment during the second quarter of 2016. As of March 31, 2016, our MISO facilities had a combined carrying value of $1.4 billion.

DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended March 31, 2016 and 2015

Item 2—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. We currently own approximately 26,000 MW of generating capacity in eight states and also provide retail electricity to 1,034,000 residential customers and 38,000 commercial, industrial, and municipal customers in Illinois, Ohio, and Pennsylvania. 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 February 24, 2016, through Atlas Power, we signed the Delta Stock Purchase Agreement to acquire GSENA (Engie S.A's United States merchant fossil portfolio) consisting of approximately 8,700 MWs of generation capacity located in ERCOT, PJM, and ISO-NE. The JV has financing commitments for the $3.3 billion acquisition, as well as related transaction fees and working capital, with $2.25 billion in committed debt facilities and $1.185 billion in equity commitments by us and ECP Funds. We expect the transaction to close in the fourth quarter of 2016 after satisfaction or waiver of customary closing conditions, including approval from FERC, the Public Utility Commission of Texas, and expiration of Hart-Scott-Rodino waiting period, which occurred on April 1, 2016. Please read Note 3—Acquisitions for further discussion of the Delta Transaction and related agreements.

On March 18, 2016, we entered into a bilateral contract to sell 2,300 MW of cleared PJM capacity (1,500 MW of Base Capacity and 800 MW of Capacity Performance ("CP") Product) in Planning Year 2017-2018 and 1,900 MW of cleared PJM capacity (1,000 MW of Base Capacity and 900 MW of CP Product) in Planning Year 2018-2019. In exchange, we received $198 million in cash proceeds in the first quarter of 2016. The buyer in this transaction will receive capacity payments from PJM during the Planning Years 2017-2018 and 2018-2019 in the amounts of $110 million and $109 million, respectively. Dynegy will continue to be subject to the performance obligations as well as any associated performance penalties and bonus payments for those planning years. Please read Note 12—Debt 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 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. Genco's

$825 million Senior Notes are non-recourse to Dynegy.

As a result of continued weak energy prices, unsold capacity volumes, on-going required maintenance and environmental expenditures, as well as consideration of a $300 million debt maturity in 2018; we will begin a strategic review of IPH’s Genco subsidiary immediately. We intend to resolve this situation by either restructuring the Genco debt to achieve a more sustainable business model or transitioning ownership to the debt holders. Please read Note 12—Debt for further discussion.

Liquidity. The following table summarizes our liquidity position at March 31, 2016:

	March 31, 2016		
(amounts in millions)	Dynegy Inc.	IPH (1) (2)	Total
Revolving facilities and LC capacity (3)	$1,480	$39	$1,519
Less: Outstanding LCs	(496)	(35)	(531)
Revolving facilities and LC availability	984	4	988
Cash and cash equivalents	743	78	821
Total available liquidity (4)	$1,727	$82	$1,809

(1) Includes Cash and cash equivalents of $55 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) Dynegy includes: (i) $950 million of aggregate available capacity related to our incremental revolving credit facilities,(ii) $475 million of available capacity related to the five-year senior secured revolving credit facility, and (iii) $55 million related to an LC. IPH includes (i) up to a maximum of $25 million related to the two-year secured LC facility and (ii) $14 million related to our fully cash collateralized LC and reimbursement agreement. Please read Note 12—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 March 31, 2016, there was approximately $25 million outstanding on the note, which is not reflected in the table above.

In conjunction with the JV's $1.85 billion committed senior secured debt financing arrangements for the Delta Transaction, we have secured an incremental revolver commitment in the amount of $100 million at Dynegy Inc., and the JV has secured an incremental revolver commitment in the amount of $25 million at Atlas Power, for liquidity needs.

The following table presents net cash from operating, investing, and financing activities for the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31,	
(amounts in millions)	2016	2015
Net cash provided by (used in) operating activities	$191	$(55)
Net cash used in investing activities	$(57)	$(40)
Net cash provided by (used in) financing activities	$182	$(41)

Operating Activities

Historical Operating Cash Flows. Cash provided by operations totaled $191 million for the three months ended March 31, 2016. During the period, our power generation business provided cash of $259 million primarily due to the operation of our power generation facilities and retail operations. Corporate and other activities used cash of $19 million primarily due to interest payments on our various debt agreements. Changes in working capital and other, including general and administrative expenses, used cash of $49 million, net, during the period.

Cash used in operations totaled $55 million for the three months ended March 31, 2015. During the period, our power generation business provided cash of $111 million primarily due to the operation of our power generation facilities and retail operations. Corporate and other activities used cash of $99 million primarily due to interest payments on the Senior Notes issued in 2014 of $92 million funded into the escrow account related to those Senior Notes, interest payments related to our Credit Agreement, Senior Notes and Genco Senior Notes of $16 million, and payments for acquisition-related costs of $8 million, offset by $17 million related to the Ponderosa Pine Energy, LLC cash receipt. In addition, changes in working capital and other, including general and administrative expenses, used cash of approximately $67 million.

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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 Energized” initiative.

Collateral Postings. We use a portion of our capital resources in the form of cash and LCs to satisfy counterparty collateral demands. The following table summarizes our collateral postings to third parties at March 31, 2016 and December 31, 2015:

(amounts in millions)	March 31, 2016	December 31, 2015
Dynegy Inc.:		
Cash (1)	$ 147	$ 159
LCs	496	475
Total Dynegy Inc.	643	634
IPH:		
Cash (1) (2)	17	11
LCs (3) (4)	35	45
Total IPH	52	56
Total	$ 695	$ 690

(1) Includes broker margin as well as other collateral postings included in Prepayments and other current assets on our unaudited consolidated balance sheets. At March 31, 2016 and December 31, 2015, $79 million and $106 million, respectively, of cash posted as collateral were netted against Liabilities from risk management activities on our unaudited consolidated balance sheets.

(2) Includes cash of approximately $7 million and $1 million related to Genco at March 31, 2016 and December 31, 2015, respectively.

(3) Includes LCs of approximately $13 million and $20 million outstanding as of March 31, 2016 and December 31, 2015, respectively, related to the cash-backed LC facility at Illinois Power Marketing Company (“IPM”). Please read Note 12—Debt—Letter of Credit Facilities for further discussion.

(4) Includes LCs of approximately $22 million related to the two-year secured LC entered into by IPM and collateralized by IPRG receivables.

Collateral postings decreased from December 31, 2015 to March 31, 2016 primarily due to reduced collateral requirements of hedging activity. LCs posted as collateral increased primarily due to increased postings to various ISOs for annual transmission production auctions. The fair value of our derivatives collateralized by first priority liens included liabilities of $146 million and $167 million at March 31, 2016 and December 31, 2015, respectively.

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Investing Activities

Historical Investing Cash Flows. During the three months ended March 31, 2016, we paid $65 million in capital expenditures and received an $8 million cash inflow related to distributions from our unconsolidated investment in Elwood. Our capital spending by reportable segment was as follows:

(amounts in millions)	Three Months Ended March 31, 2016	2015
Coal	$19	$ 3
IPH	11	11
Gas	31	24
Other	4	2
Total (1)	$65	$ 40

(1) Includes capitalized interest of $4 million and $3 million for the three months ended March 31, 2016 and 2015, respectively.

Future Investing Cash Flows. We expect capital expenditures for the remainder of 2016 to be approximately $254 million, which is comprised of $49 million, $18 million, $183 million, and $4 million in Coal, IPH, Gas, and Other, respectively. The capital budget is subject to revision as opportunities arise or circumstances change. Additionally, our future investing cash flows will be reduced by funds used to fund Atlas Power.

Financing Activities

Historical Financing Cash Flows. Cash provided by financing activities totaled $182 million for the three months ended March 31, 2016 primarily due to $198 million of proceeds related to our forward capacity agreement, offset by (i) $5 million in repayments associated with our inventory financing agreements and term loan, (ii) $5 million in dividend payments on our Mandatory Convertible Preferred Stock, and (iii) $4 million in interest rate swap settlement payments. Please read Note 12—Debt and Note 16—Capital Stock for further discussion.

Cash used in financing activities totaled $41 million for the three months ended March 31, 2015 primarily due to (i) $23 million in repayments associated with repurchase agreements related to emission credits, (ii) $7 million in dividend payments on our Mandatory Convertible Preferred Stock, (iii) $4 million in interest rate swap settlement payments, (iv) $4 million in released restricted stock units for payment of employee withholding taxes in connection with our stock award plans, and (v) $2 million in principal payments on borrowings on the Tranche B-2 Term Loan. Please read Note 12—Debt for further discussion.

Future Financing Cash Flows. We are obligated to pay dividends on our mandatory convertible preferred stock 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. Please read Note 16—Capital Stock for further discussion. Our future cash flows will be increased by proceeds from the debt issued by Atlas Power for the Delta Transaction and the issuance of our common stock to ECP.

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 12—Debt in our Form 10-K for further discussion.

Financial Covenants

Credit Agreement. Our 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:

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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 March 31, 2016 was 31 percent of the aggregate revolver commitment due to outstanding LCs; therefore, we tested the covenant and were in compliance at March 31, 2016.

Genco Senior Notes. 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. 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.

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 external, third-party sources are included in the definition of indebtedness and are subject to these incurrence tests.

Based on March 31, 2016 calculations, Genco did not meet the minimum ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources.

Please read Note 12—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 three months ended March 31, 2016 and 2015, we paid an aggregate of $5 million and $7 million in dividends on February 1, 2016 and February 2, 2015, respectively.

On April 1, 2016, 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 February 1, 2016 and ending on April 30, 2016. Such dividends were paid on May 2, 2016 to stockholders of record as of April 15, 2016.

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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	Caa3	CCC+

RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results

In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three months ended March 31, 2016 and 2015. 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). All references to hedging within this Form 10-Q relate to economic hedging activities as we do not elect hedge accounting.

We completed the EquiPower Acquisition and Duke Midwest Acquisition on April 1, 2015 and April 2, 2015, respectively; therefore, the results of our newly acquired plants within our Coal and Gas segments are not included in our consolidated results for the three months ended March 31, 2015. Please read Note 3—Acquisitions—ECP Purchase Agreements and Duke Midwest Purchase Agreement for further discussion.

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Consolidated Summary Financial Information — Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

The following table provides summary financial data regarding our unaudited consolidated results of operations for the three months ended March 31, 2016 and 2015, respectively:

(amounts in millions)	Three Months Ended March 31, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues				
Energy	$803	$543	$ 260	48 %
Capacity	201	51	150	NM
Mark-to-market income, net	112	31	81	NM
Contract amortization	(17)	(6)	(11)	(183)%
Other (1)	24	13	11	85 %
Total revenues	1,123	632	491	78 %
Cost of sales, excluding depreciation expense	(545)	(377)	(168)	(45)%
Gross margin	578	255	323	127 %
Operating and maintenance expense	(221)	(111)	(110)	(99)%
Depreciation expense	(171)	(64)	(107)	(167)%
General and administrative expense	(37)	(30)	(7)	(23)%
Acquisition and integration costs	(4)	(90)	86	96 %
Operating income (loss)	145	(40)	185	NM
Earnings from unconsolidated investments	2	—	2	NM
Interest expense	(142)	(136)	(6)	(4)%
Other income and expense, net	1	(5)	6	120 %
Income (loss) before income taxes	6	(181)	187	103 %
Income tax expense	(16)	—	(16)	NM
Net loss	(10)	(181)	171	94 %
Less: Net loss attributable to noncontrolling interest	—	(1)	1	100 %
Net loss attributable to Dynegy Inc.	$(10)	$(180)	$ 170	94 %

(1) For the three months ended March 31, 2016 and 2015, respectively, Other includes $14 million and $10 million in ancillary services, $3 million and $1 million in tolling revenue, and $7 million and $2 million in RMR and other miscellaneous items.

The following tables provide summary financial data regarding our operating income (loss) by segment for the three months ended March 31, 2016 and 2015, respectively:

	Three Months Ended March 31, 2016				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$380	$167	$576	$—	$1,123
Cost of sales, excluding depreciation expense	(176)	(99)	(270)	—	(545)
Gross margin	204	68	306	—	578
Operating and maintenance expense	(111)	(45)	(64)	(1)	(221)
Depreciation expense	(39)	(9)	(122)	(1)	(171)
General and administrative expense	—	—	—	(37)	(37)
Acquisition and integration costs	—	—	—	(4)	(4)
Operating income (loss)	$54	$14	$120	$(43)	$145

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	Three Months Ended March 31, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$142	$219	$271	$—	$632
Cost of sales, excluding depreciation expense	(88)	(138)	(151)	—	(377)
Gross margin	54	81	120	—	255
Operating and maintenance expense	(37)	(51)	(23)	—	(111)
Depreciation expense	(10)	(8)	(45)	(1)	(64)
General and administrative expense	—	—	—	(30)	(30)
Acquisition and integration costs	—	—	—	(90)	(90)
Operating income (loss)	$7	$22	$52	$(121)	$(40)

Discussion of Consolidated Results of Operations

Revenues. Consolidated revenues increased $491 million from $632 million during the three months ended March 31, 2015 to $1,123 million during the three months ended March 31, 2016. Our newly acquired plants, higher capacity revenues, and higher mark-to-market gains on hedging transactions contributed to increased revenues. This was partially offset by lower revenues due to lower volumes and energy prices realized by our legacy plants as a result of mild winter weather across our key markets.

The following table summarizes the change in revenues by segment:

(amounts in millions)	Coal	IPH	Gas	Total
Revenues, net of hedges, attributable to our newly acquired plants	$269	$—	$392	$661
Lower revenues attributable to our legacy plants:				
Lower energy revenues, net of settled hedges, due to lower generation volumes at the Coal and IPH segments and lower prices at the Gas segment	(42)	(66)	(80)	(188)
Higher wholesale capacity revenues due to higher pricing	4	23	3	30
Higher (lower) mark-to-market gains on hedging transactions	20	29	(7)	42
Lower retail revenues, net of hedges	(14)	(39)	—	(53)
Lower (higher) contract amortization	—	2	(1)	1
Other	1	(1)	(2)	(2)
Total change in revenues	$238	$(52)	$305	$491

Cost of Sales. Cost of sales increased $168 million from $377 million during the three months ended March 31, 2015 to $545 million during the three months ended March 31, 2016, primarily driven by costs associated with our newly acquired plants, partially offset by lower costs from our legacy plants primarily due to a reduction in natural gas prices and lower coal and freight costs as a result of lower generation volumes.

The following table summarizes the change in cost of sales by segment:

(amounts in millions)	Coal	IPH	Gas	Total
Cost of sales attributable to our newly acquired plants	$105	$—	$180	$285
Lower cost of sales attributable to our legacy plants:				
Lower coal and freight costs due to lower generation volumes at the Coal and IPH segments and favorable contract rates at the Gas segment	(25)	(43)	(6)	(74)
Lower natural gas prices	—	—	(57)	(57)
Higher retail costs	7	2	—	9
Lower contract amortization due to the expiration of certain coal and gas transport contracts	1	2	2	5
Total change in cost of sales	$88	$(39)	$119	$168

Operating and Maintenance Expense. Operating and maintenance (“O&M”) expense increased $110 million from $111 million for the three months ended March 31, 2015 to $221 million for the three months ended March 31, 2016 primarily due to our newly acquired plants.

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Depreciation Expense. Depreciation expense increased by $107 million from $64 million for the three months ended March 31, 2015 to $171 million for the three months ended March 31, 2016 primarily due to our newly acquired plants.

General and Administrative Expense. General and administrative expense increased by $7 million from $30 million for the three months ended March 31, 2015 to $37 million for the three months ended March 31, 2016. 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 $86 million from $90 million for the three months ended March 31, 2015 to $4 million for the three months ended March 31, 2016. Acquisition and integration costs for the three months ended March 31, 2016 consisted of advisory and consulting fees related to the Delta Stock Purchase Agreement and the Acquisitions of $3 million and $1 million, respectively. Acquisition and integration costs for the three months ended March 31, 2015 consisted of $48 million in Bridge Loan financing fees and $42 million in advisory and consulting fees related to the Acquisitions. Please read Note 3—Acquisitions for further discussion.

Earnings from Unconsolidated Investments. Earnings from unconsolidated investments increased by $2 million from earnings of zero for the three months ended March 31, 2015 to earnings of $2 million for the three months ended March 31, 2016. We recorded $2 million in earnings from our 50 percent Elwood investment during the three months ended March 31, 2016.

Interest Expense. Interest expense increased by $6 million from $136 million for the three months ended March 31, 2015 to $142 million for the three months ended March 31, 2016 primarily due to amortization of financing costs and fees associated with our revolving facilities. Please read Note 12—Debt for further discussion.

Other Income and Expense, net. Other income and expense, net increased by $6 million from expense of $5 million for the three months ended March 31, 2015 to income of $1 million for the three months ended March 31, 2016 primarily due to the change in fair value of our common stock warrants.

Income Tax Expense. We reported income tax expense of $16 million and zero for the three months ended March 31, 2016 and 2015, respectively. Income tax expense for the three months ended March 31, 2016 was primarily due to state income tax resulting from a change in our corporate tax structure.

As of March 31, 2016, 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. Please read Note 14—Income Taxes for further discussion.

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, and (iv) other material items. Beginning in 2016, Adjusted EBITDA also excludes non-cash compensation expense. Non-cash compensation expense of $6 million was not excluded during the three months ended 2015.

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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, 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 March 31, 2016 Compared to Three Months Ended March 31, 2015

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended March 31, 2016:

	Three Months Ended March 31, 2016				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(10)
Income tax expense					16
Other items, net (1)					(1)
Interest expense					142
Earnings from unconsolidated investments					(2)
Operating income (loss)	$54	$14	$120	$(43)	$145
Depreciation expense	39	9	122	1	171
Amortization expense	(12)	(1)	27	—	14
Earnings from unconsolidated investments	—	—	2	—	2
Other items, net	—	—	—	1	1
EBITDA	81	22	271	(41)	333
Earnings from unconsolidated investments	—	—	(2)	—	(2)
Cash distributions from unconsolidated investments	—	—	5	—	5
Acquisition and integration costs	—	—	—	4	4
Mark-to-market adjustments	(40)	(3)	(62)	—	(105)
Change in fair value of common stock warrants	—	—	—	(1)	(1)
ARO accretion expense	3	2	—	—	5
Wood River energy margin and O&M	5	—	—	—	5
Non-cash compensation expense	—	—	1	6	7
Other	1	—	(1)	—	—
Adjusted EBITDA	$50	$21	$212	$(32)	$251

(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended March 31, 2015:

	Three Months Ended March 31, 2015				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(180)
Loss attributable to noncontrolling interest					(1)
Other items, net (1)					5
Interest expense					136
Operating income (loss)	$7	$22	$52	$(121)	$(40)
Depreciation expense	10	8	45	1	64
Amortization expense	(1)	(1)	(2)	—	(4)
Other items, net	—	—	—	(5)	(5)
EBITDA	16	29	95	(125)	15
Acquisition and integration costs	—	—	—	90	90
Loss attributable to noncontrolling interest	—	1	—	—	1
Mark-to-market adjustments	(7)	(11)	(13)	—	(31)
Change in fair value of common stock warrants	—	—	—	5	5
ARO accretion expense	1	3	—	—	4
Other	—	—	—	1	1
Adjusted EBITDA	$10	$22	$82	$(29)	$85

(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

Adjusted EBITDA was $85 million for the three months ended March 31, 2015 compared to $251 million for the three months ended March 31, 2016. The $166 million increase in Adjusted EBITDA was due to $209 million from our newly acquired plants, partially offset by a $43 million decrease from our legacy plants. The decrease from our legacy plants was driven by lower energy margin, net of hedges, in all segments primarily due to lower generation volumes at the Coal and IPH segments, and lower spark spreads at the Gas segment as a result of mild winter weather across our key markets. This decrease was partially offset by higher capacity revenues in all segments. Please read Discussion of Segment Adjusted EBITDA for further information.

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Discussion of Segment Adjusted EBITDA — Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

Coal Segment

The following table provides summary financial data regarding our Coal segment results of operations for the three months ended March 31, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Three Months Ended March 31, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating revenues				
Energy	$281	$133	$ 148	111 %
Capacity	52	2	50	NM
Mark-to-market income, net	47	7	40	NM
Contract amortization	(2)	—	(2)	NM
Other (1)	2	—	2	NM
Total operating revenues	380	142	238	168 %
Operating costs				
Cost of sales	(189)	(89)	(100)	(112)%
Contract amortization	13	1	12	NM
Total operating costs	(176)	(88)	(88)	(100)%
Gross margin	204	54	150	NM
Operating and maintenance expense	(111)	(37)	(74)	(200)%
Depreciation expense	(39)	(10)	(29)	NM
Operating income	54	7	47	NM
Depreciation expense	39	10	29	NM
Amortization expense	(12)	(1)	(11)	NM
EBITDA	81	16	65	NM
Mark-to-market adjustments	(40)	(7)	(33)	NM
ARO accretion expense	3	1	2	200 %
Wood River energy margin and O&M	5	—	5	NM
Other	1	—	1	NM
Adjusted EBITDA	$50	$10	$ 40	NM
Million Megawatt Hours Generated	7.6	4.8	2.8	58 %
IMA for Coal-Fired Facilities (2)	81 %	91 %		
Average Capacity Factor for Coal-Fired Facilities (3)	46 %	74 %		
Average Quoted Market On-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$25.61	$39.27	$ (13.66)	(35)%
Commonwealth Edison (NI Hub)	$27.35	$40.82	$ (13.47)	(33)%
Mass Hub	$33.85	$96.19	$ (62.34)	(65)%
AD Hub	$28.80	$45.26	$ (16.46)	(36)%
Average Quoted Market Off-Peak Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$20.18	$28.97	$ (8.79)	(30)%
Commonwealth Edison (NI Hub)	$20.55	$27.85	$ (7.30)	(26)%
Mass Hub	$26.21	$76.43	$ (50.22)	(66)%
AD Hub	$22.92	$32.27	$ (9.35)	(29)%

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(1) For the three months ended March 31, 2016 and 2015, respectively, Other includes $1 million and zero in ancillary services and $1 million and zero in other miscellaneous items.

(2) IMA is an internal measurement calculation that reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched. This calculation excludes certain events outside of management control such as weather related issues. The 2016 calculation excludes our Brayton Point facility and CTs. In 2016, the IMA for our facilities within MISO and PJM (excluding CTs) was 89 percent and 77 percent, respectively.

(3) Reflects actual production as a percentage of available capacity. The 2016 calculation excludes our Brayton Point facility and CTs. In 2016, the average capacity factors for our facilities within MISO and PJM (excluding CTs) were 50 percent and 43 percent, respectively.

(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 March 31, 2016 was $54 million compared to $7 million for the three months ended March 31, 2015. Adjusted EBITDA was $50 million for the three months ended March 31, 2016 compared to $10 million for the three months ended March 31, 2015. The $40 million increase in Adjusted EBITDA was due to $56 million from our newly acquired plants, partially offset by a $16 million decrease from our legacy plants, excluding Wood River. The decrease from our legacy plants was driven by lower energy margin, net of hedges, primarily due to lower generation volumes as a result of mild winter weather and higher O&M costs. This decrease was partially offset by higher wholesale capacity revenues.

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IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the three months ended March 31, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Three Months Ended March 31, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating revenues				
Energy	$128	$196	$ (68)	(35)%
Capacity	39	16	23	144 %
Mark-to-market income, net	3	11	(8)	(73)%
Contract amortization	(4)	(6)	2	33 %
Other (1)	1	2	(1)	(50)%
Total operating revenues	167	219	(52)	(24)%
Operating costs				
Cost of sales	(104)	(145)	41	28 %
Contract amortization	5	7	(2)	(29)%
Total operating costs	(99)	(138)	39	28 %
Gross margin	68	81	(13)	(16)%
Operating and maintenance expense	(45)	(51)	6	12 %
Depreciation expense	(9)	(8)	(1)	(13)%
Operating income	14	22	(8)	(36)%
Depreciation expense	9	8	1	13 %
Amortization expense	(1)	(1)	—	NM
EBITDA	22	29	(7)	(24)%
Income attributable to noncontrolling interest	—	1	(1)	(100)%
Mark-to-market adjustments	(3)	(11)	8	73 %
ARO accretion expense	2	3	(1)	(33)%
Adjusted EBITDA	$21	$22	$ (1)	(5)%
Million Megawatt Hours Generated	3.3	5.2	(1.9)	(37)%
IMA for IPH Facilities (2)	86 %	93 %		
Average Capacity Factor for IPH Facilities (3)	39 %	60 %		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$25.61	$39.27	$ (13.66)	(35)%
Off-Peak: Indiana (Indy Hub)	$20.18	$28.97	$ (8.79)	(30)%

(1) For the three months ended March 31, 2016 and 2015, respectively, Other includes $2 million and zero in ancillary services and ($1) million and $2 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 three months ended March 31, 2016 was $14 million compared to $22 million for the three months ended March 31, 2015. Adjusted EBITDA was $21 million for the three months ended March 31, 2016 compared to $22 million for the three months ended March 31, 2015. The $1 million decrease in Adjusted EBITDA resulted from lower energy margin, net of hedges, primarily due to lower generation volumes driven primarily by mild winter weather as well as lower retail

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margin. This decrease was partially offset by higher wholesale capacity revenues and lower O&M costs primarily due to fewer planned outages.

Gas Segment

The following table provides summary financial data regarding our Gas segment results of operations for the three months ended March 31, 2016 and 2015, respectively:

(dollars in millions, except for price information)	Three Months Ended March 31, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$394	$214	$ 180	84 %
Capacity	110	33	77	233 %
Mark-to-market income, net	62	13	49	NM
Contract amortization	(11)	—	(11)	NM
Other (1)	21	11	10	91 %
Total operating revenues	576	271	305	113 %
Operating Costs				
Cost of sales	(254)	(153)	(101)	(66)%
Contract amortization	(16)	2	(18)	NM
Total operating costs	(270)	(151)	(119)	(79)%
Gross margin	306	120	186	155 %
Operating and maintenance expense	(64)	(23)	(41)	(178)%
Depreciation expense	(122)	(45)	(77)	(171)%
Operating income	120	52	68	131 %
Depreciation expense	122	45	77	171 %
Amortization expense	27	(2)	29	NM
Earnings from unconsolidated investments	2	—	2	NM
EBITDA	271	95	176	185 %
Earnings from unconsolidated investments	(2)	—	(2)	NM
Cash distributions from unconsolidated investments	5	—	5	NM
Mark-to-market adjustments	(62)	(13)	(49)	NM
Non-cash compensation expense	1	—	1	NM
Other	(1)	—	(1)	NM
Adjusted EBITDA	$212	$82	$ 130	159 %
Million Megawatt Hours Generated	13.3	5.0	8.3	166 %
IMA for Combined Cycle Facilities (2)	96 %	99 %		
Average Capacity Factor for Combined Cycle Facilities (3)	62 %	52 %		
Average Market On-Peak Spark Spreads ($/MWh) (4):				
Commonwealth Edison (NI Hub)	$13.06	$17.68	$ (4.62)	(26)%
PJM West	$18.72	$17.55	$ 1.17	7 %
North of Path 15 (NP 15)	$10.72	$12.67	$ (1.95)	(15)%
New York—Zone A	$16.70	$39.80	$ (23.10)	(58)%
Mass Hub	$10.83	$14.92	$ (4.09)	(27)%
AD Hub	$19.83	$31.12	$ (11.29)	(36)%
Average Market Off-Peak Spark Spreads ($/MWh) (4):				
Commonwealth Edison (NI Hub)	$6.26	$4.71	$ 1.55	33 %
PJM West	$12.81	$0.98	$ 11.83	NM
North of Path 15 (NP 15)	$6.03	$7.25	$ (1.22)	(17)%

New York—Zone A	$4.92	$25.32	$ (20.40)	(81)%
Mass Hub	$3.19	$(4.84)	$ 8.03	166 %
AD Hub	$13.95	$18.13	$ (4.18)	(23)%
Average natural gas price—Henry Hub ($/MMBtu) (5)	$1.98	$2.87	$ (0.89)	(31)%

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(1) For the three months ended March 31, 2016 and 2015, respectively, Other includes $11 million and $10 million in ancillary services, $3 million and $1 million in tolling revenue and $7 million and zero in RMR and other miscellaneous items.

(2) 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.

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

(4) 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.

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

Operating income for the three months ended March 31, 2016 was $120 million compared to $52 million for the three months ended March 31, 2015. Adjusted EBITDA totaled $212 million for the three months ended March 31, 2016 compared to $82 million for the three months ended March 31, 2015. The $130 million increase in Adjusted EBITDA was due to $153 million from our newly acquired plants, particularly in PJM, partially offset by a $23 million decrease from our legacy plants. The decrease from our legacy plants was driven by lower energy margin, net of hedges, primarily due to lower spark spreads, mainly at our Independence facility, driven by mild winter weather and higher O&M costs, partially offset by higher capacity revenues.

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Outlook
Since our emergence from bankruptcy in October 2012, we have continued to reposition our fleet, primarily through acquisitions, to concentrate on the most attractive power markets while maintaining a disciplined cost structure. In 2013, our fleet capacity consisted of 65 percent MISO/CAISO resources and 35 percent PJM/ISO-NE/NYISO resources. Today our fleet is made up of 38 percent MISO/CAISO and 62 percent PJM/ISO-NE/NYISO. Upon closing the Delta Transaction, which is expected to occur in the fourth quarter of 2016, our fleet will consist of 26 percent MISO/CAISO and 74 percent PJM/ISO-NE/ERCOT/NYISO. Additionally, our fuel mix will have transitioned to 63 percent gas and 37 percent coal versus our 2014 mix of 46 percent gas and 54 percent coal.
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 Operating Segments
Coal. The Coal segment is comprised of 11 power generation facilities located within MISO (3,008 MW), PJM (3,884 MW) and the ISO-NE (1,528 MW) regions, with a total generating capacity of 8,420 MW. On May 3, 2016, Dynegy announced the shutdown of two units at its Baldwin power generation facility ("Baldwin") in Baldwin, Illinois. Subject to the approval of MISO, we expect to shut down the units (1,220 MW) over the next year. This decision was made after the units failed to recover their basic operating costs in the most recent MISO auction. Factors influencing these actions included a low power pricing environment, a lack of capacity revenue and significant maintenance and environmental expenditures required to appropriately maintain the facilities. Please read Note 20—Subsequent Event for further discussion.
MISO has recently approved our retirement of the final two units at the 465 MW Wood River Power Station in Alton, Illinois on June 1, 2016. Additionally, our Brayton Point facility is expected to be retired in ISO-NE in June 2017. Upon the completion of the planned retirements and shutdowns, our Coal segment will include 5,207 MW of generation capacity, of which 1,323 MW will operate in MISO and 3,884 MW will operate in PJM.
As of April 19, 2016, our expected remaining generation volumes, excluding Brayton Point and Wood River, are approximately 70 percent hedged volumetrically for 2016. Excluding the planned retirements and shutdowns, our generation volumes are approximately 38 percent hedged volumetrically for 2017. We plan to continue our hedging program over a one- to three-year period using various instruments, including retail sales. Dynegy's portfolio beyond 2016 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 facilities.
As of April 19, 2016, excluding Brayton Point, Wood River, and the non-operated jointly-owned generating units, our expected coal requirements for 2016 are 95 percent contracted and 92 percent priced. Our forecasted coal requirements for 2017, excluding the planned retirements and shutdowns, as well as the non-operated jointly-owned generating units, are 80 percent contracted and 72 percent priced. We look to procure and price additional fuel and transportation opportunistically. Our coal transportation requirements are fully contracted for 2016 and 99 percent contracted for 2017. Our coal transportation requirements are approximately 67 percent contracted for 2018 to 2020. 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.
We 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. We cleared no volume in the MISO Planning Year 2016-2017 capacity auction incremental to our load obligations.
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 New England, almost all of our capacity sales are made through ISO-NE capacity auctions.

In PJM, we 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 Capacity Performance ("CP") product beginning with Planning Year 2016-2017. In PJM, we 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-

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performance charges assessed during emergency conditions, from June through September. In PJM, we 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 power generation facilities, totaling 4,178 MW and primarily operates in MISO. Joppa, which is within the Electric Energy, Inc. control area, is interconnected to Tennessee Valley Authority and Louisville Gas and Electric Company, but primarily sells its capacity and energy to MISO. We currently offer a portion of our IPH segment generating capacity into PJM. As of June 1, 2016, our Coffeen, Duck Creek, E.D. Edwards and Newton facilities will have 937 MW, or 22 percent of IPH's capacity, which is electrically tied into PJM through pseudo-tie arrangements.

On May 3, 2016, Dynegy announced the shutdown of one of the units at its Newton power generation facility ("Newton") in Newton, Illinois. Subject to the approval of MISO, we expect to shut down the unit (615 MW) this year. This decision was made after Newton failed to recover its basic operating costs in the most recent MISO auction. Factors influencing this action included a low power pricing environment, a lack of capacity revenue and significant maintenance and environmental expenditures required to appropriately maintain the facility. Upon the shutdown of the Newton unit, IPH will have 3,563 MW. Please read Note 20—Subsequent Event for further discussion.

Additionally, as a result of continued weak energy prices, unsold capacity volumes, on-going required maintenance and environmental expenditures, as well as consideration of a $300 million debt maturity in 2018; we will begin a strategic review of IPH's Genco subsidiary immediately. We intend to resolve this situation by either restructuring the Genco debt to achieve a more sustainable business model or transitioning ownership to the debt holders. Please read Note 12—Debt for further discussion.

As of April 19, 2016, IPH's expected remaining generation volumes are approximately 64 percent hedged volumetrically for 2016. Excluding the planned shutdown, IPH is approximately 48 percent hedged volumetrically for 2017. IPH will continue to use our retail business, Homefield Energy, to hedge a portion of the output from our IPH facilities. The retail hedges are well correlated to our facilities due to the close proximity of the hedge and through participation in FTR markets. Homefield Energy's ability to keep and possibly grow its existing market share will impact IPH's hedge levels in the future.

As of April 19, 2016, our expected coal requirements for IPH for 2016 are 95 percent contracted and 72 percent priced. Our forecasted coal requirements for 2017, excluding the planned shutdown, are 79 percent contracted and 58 percent priced. We look to procure and price additional fuel opportunistically. Our coal transportation requirements are fully contracted for 2016 and 2017. Our coal transportation requirements are approximately 58 percent contracted for 2018 to 2020.

In addition, we recently entered into a new long-term coal transportation agreement for our Joppa facility which will begin in 2018 and includes a rate reduction from the 2017 rate.

On February 24, 2016, IPM was awarded a three year capacity and energy sale contract for 959 MW with capacity revenue of $152 million. This contract supports 112 communities in Illinois represented by Good Energy, and commences on June 1, 2016.

IPH realized capacity sales in the MISO Planning Year 2014-2015 capacity auction, clearing 1,995 MW to offset retail load obligations. IPH cleared 1,864 MW in the MISO Planning Year 2015-2016 capacity auction, including 1,709 MW to offset retail load obligations. IPH only sold 155 MW that received the $150 per MW-day clearing price. IPH cleared 1,828 MW in the MISO Planning Year 2016-2017 capacity auction to offset retail load obligations.

In PJM, we cleared no volume in the Planning Year 2014-2015 capacity auction, 301 MW in the Planning Year 2015-2016 capacity auction, 867 MW in the Planning Year 2016-2017 capacity auction (138 MW legacy capacity and 729 MW CP), 847 MW in the Planning Year 2017-2018 capacity auction (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 (7,337 MW), CAISO (2,694 MW), ISO-NE (2,429 MW) and NYISO (1,126 MW) regions, totaling 13,586 MW of electric generating capacity.

In PJM, we are installing a total of 272 MW of uprates, which will be accomplished primarily through upgrades to the hot gas path components of our combined cycle gas turbines. The uprates started in the Fall of 2015 and are expected

to be completed in the Spring of 2017.
In New England, at our Lake Road and Milford facilities, we cleared 70 MW of new uprates in FCA-10, at a capacity rate of $7.03 per kW-month for seven years beginning with Planning Year 2019-2020 and extending through Planning Year 2025-2026.
In New York, we will be installing uprates at our Independence facility in 2016 that are expected to result in 45 MW of additional summer capacity and up to 90 MW of additional winter capacity.

Excluding volumes subject to tolling agreements, as of April 19, 2016, our Gas portfolio is 61 percent hedged volumetrically through 2016 and approximately 22 percent hedged volumetrically for 2017. 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, we 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, we 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, 2,148 MW in the Planning Year 2018-2019 capacity auction, and 2,226 MW in the Planning Year 2019-2020 capacity auction. In New England, almost all of our capacity sales are made through ISO-NE capacity auctions.

In New York, almost 90 percent of our Independence facility's summer capacity had been sold bilaterally prior to the most recent auction, covering the Summer 2016 planning period. Including bilateral and auction sales as of April 19, 2016, 872 MW were sold for the Summer 2016 planning period, 693 MW were sold for the Winter 2016-2017 planning period, 818 MW were sold for the Summer 2017 planning period, and 380 MW were sold for the Winter 2017-2018 planning period.

In October 2015, we contracted Resources 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. Our Moss Landing 6 and 7 Units have tolling and RA agreements in place that continue through December 31, 2016.

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 Moss Landing Units 1 and 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 and 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 which PG&E proposes in its 2015 proceeding would result in Moss Landing Units 1 and 2 likely experiencing a decline in dispatch hours. Dynegy is actively participating in the hearing process before the CPUC and is advocating positions that would maintain the ability of Moss Landing Units 1 and 2 to compete in the California electricity market. Post-hearing briefing concluded in May 2015 and Oral Argument was held on October 28, 2015. A decision is expected in mid-2016.

Capacity Markets

MISO. We currently have approximately 7,186 MW of power generation in MISO. With the retirement of Wood River, the shutdown of two units at Baldwin and one unit at Newton and the PJM pseudo-tie arrangements that begin June 1, 2016, we will have approximately 3,949 MW 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:

	2014-2015	2015-2016	2016-2017
Price per MW-day	\$16.75	\$150.00	\$72.00

As previously noted, we cleared no volume in the MISO Planning Year 2014-2015 capacity auction. Our Coal and IPH segments cleared 398 MW and 155 MW, respectively, in the MISO Planning Year 2015-2016 capacity auction at $150 per MW-day, incremental to our retail load obligations. Our Coal and IPH segments cleared no incremental volumes, in excess of our retail load obligations, in the MISO Planning Year 2016-2017 capacity auction.

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We have sold capacity in planning reserve auctions, incremental auctions and through bilateral transactions. Our capacity sales, aggregated by Planning Year through Planning Year 2019-2020, are as follows:

	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
Coal Segment:					
Capacity sold (MW)	516	1,003	579	242	185
Average price per kW-month	$4.00	$2.75	$2.35	$2.68	$2.60
IPH Segment:					
Capacity sold (MW)	2,922	2,970	2,643	2,328	470
Average price per kW-month	$2.29	$4.28	$4.54	$5.09	$5.61

A majority of the Mercury and Air Toxic Standards ("MATS") related asset retirements will conclude this year; however, we expect economic retirements 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 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. We 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.

On December 31, 2015, FERC issued an order on the complaints requiring a number of prospective changes to the MISO tariff provisions associated with calculating Initial Reference Levels and Local Clearing Requirements, effective as of the 2016-2017 PRA. Under the order, FERC found that the existing tariff provision, which bases Initial Reference Levels for capacity supply offers on the estimated opportunity cost of exporting capacity to a neighboring region (for example, PJM), are no longer just and reasonable. Accordingly, FERC required MISO to set the Initial Reference Level for capacity at $0 per MW-day for the 2016-2017 PRA. Capacity suppliers may also request a facility-specific reference level from the MISO IMM. The order did not address the other arguments of the complainants regarding the 2015-2016 PRA and stated that those issues remain under consideration and will be addressed in a future order.

ISO-NE. We have approximately 3,957 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:

	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
Price per kW-month	$3.21	$3.43	$3.15	$7.03	$9.55	$7.03

The forecasted 2016 ISO-NE reserve margin is 25.2 percent versus a target reserve margin of 15.6 percent. On February 2, 2015, ISO-NE conducted the capacity auction for Planning Year 2018-2019 (FCA-9). Effective for this auction, a downward sloping demand curve replaced the vertical demand curve and the system-wide administrative pricing rules. Performance incentive rules also 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. 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 zone, where our recently acquired Dighton facility is located, had insufficient supply to satisfy its capacity

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requirements. As a result, the zone separated from Rest-of-Pool, with existing resources in the zone receiving the Net Cost of New Entry price of $11.08 per kW-month and new resources in the zone receiving the auction starting price of $17.73 per kW-month. On February 8, 2016, ISO-NE conducted the capacity auction for Planning Year 2019-2020 (FCA-10). In this auction, Rest-of-Pool cleared at $7.03 per kW-month.

We have sold capacity in FCAs, supplemental auctions and through bilateral transactions. Our capacity sales, aggregated by Planning Year through Planning Year 2019-2020, are as follows:

	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
Capacity sold (MW)	3,738	3,663	2,181	2,148	2,240
Average price per kW-month	$3.31	$3.25	$6.99	$9.66	$7.03

PJM. We currently have approximately 11,221 MW of power generation in PJM. With the expected PJM pseudo-tie arrangements from the IPH fleet beginning June 1, 2016, we will have approximately 12,158 MW of power generation in PJM. Our 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, and Kincaid), 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 Base Residual Auction 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 CP for all resources beginning with Planning Year 2020-2021. The most recent Reliability Pricing Model auction results for PJM's RTO and MAAC zones, in which our assets are located, are as follows for each Planning Year:

	2014-2015	2015-2016	2016-2017		2017-2018		2018-2019	
	Legacy Capacity	Legacy Capacity	Legacy Capacity	CP	Legacy Capacity	CP	Base	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

We have sold capacity in base residual auctions, incremental auctions, transitional auctions, and through bilateral transactions. Our capacity sales, aggregated by Planning Year and capacity type through Planning Year 2018-2019, are as follows:

	2015-2016	2016-2017	2017-2018	2018-2019
Capacity sold (MW)	9,349	9,601	9,822	9,729
Average price per MW-day	$146.53	$120.30	$139.58	$180.36

NYISO. We have approximately 1,126 MW of power generation in NYISO. The most recent seasonal 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 2014-2015	Summer 2015	Winter 2015-2016	Summer 2016
Price per kW-month	$2.90	$3.50	$1.25	$3.62

We have sold capacity in seasonal strip auctions, supplemental auctions, and through bilateral transactions. Our capacity sales, aggregated by season through Summer 2019, are as follows:

	Winter 2015-2016	Summer 2016	Winter 2016-2017	Summer 2017	Winter 2017-2018	Summer 2018	Winter 2018-2019	Summer 2019
Capacity sold (MW)	1,124	872	693	818	380	340	185	125
	$2.19	$3.38	$2.57	$3.40	$3.10	$3.31	$3.13	$3.20

Average price
per kW-month

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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 solicitations, broker markets, and directly with bilateral transactions for both the Standard and Flexible RA capacity. Beginning on or after May 1, 2016, CAISO is expected to implement the voluntary capacity auction for annual, monthly, and intra-month procurement to cover for deficiencies in the market. This Competitive Solicitation Process will replace the existing pricing mechanism for CPM and will provide another avenue to sell RA capacity. Like CPM, we expect this mechanism to be used infrequently because generation supply has been ample, and demand has been stagnant, mainly due to energy efficiency programs and distributed generation of residential and commercial rooftop solar.

Our capacity sales, aggregated by calendar year for the remainder of 2016 through 2019 for Moss Landing Units 1 and 2, are as follows:

	Remainder of 2016	2017	2018	2019
Capacity sold (MW)	245	725	400	850

Other Market Developments

On January 25, 2016, the U.S. Supreme Court overturned the decision of the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") and affirmed FERC's jurisdiction over compensation to Demand Response providers in wholesale competitive markets and the compensation method as proscribed in FERC Order No. 745. The decision effectively maintains the status-quo with respect to Demand Response participation in the wholesale markets, because the ISOs/RTOs refrained from making changes to market design while the case was pending.

Environmental and Regulatory Matters

Please read Item 1. Business-Environmental Matters in our Form 10-K for a detailed discussion of our environmental and regulatory matters.

The Clean Air Act

Mercury and Air Toxic Standards. In April 2016, the EPA issued a final finding that consideration of cost does not change the Agency's determination that regulation of HAP emissions from coal- and oil-fired EGUs is appropriate and necessary under CAA section 112. Numerous states have petitioned for Supreme Court review of the D.C. Circuit's decision remanding the MATS rule without vacating to consider cost.

In March 2016, the EPA finalized corrections to its November 2014 MATS rule revisions addressing startup and shutdown monitoring instrumentation. With adoption of the corrections, our startup and shutdown instrumentation extension requests are no longer needed.

The Clean Water Act

Effluent Limitation Guidelines ("ELG"). We have evaluated the ELG final rule and the Coal Combustion Residuals ("CCR") rule in light of our current management of CCR, including beneficial reuse. At this time, we estimate the cost of our compliance with the ELG rule to be approximately $290 million to $350 million. The majority of ELG compliance expenditures are expected to occur in the 2016-2023 timeframe.

Cooling Water Intake Structures. At this time, we estimate the cost of our compliance with the cooling water intake structure rule will be approximately $17 million, with the majority of spend in the 2020-2023 timeframe. This estimate excludes Moss Landing, where we preliminarily estimate the cost of our compliance under the provisions of the settlement agreement with the California State Water Resources Control Board to be approximately $10 million in aggregate through 2020.

Coal Combustion Residuals

EPA CCR Rule. At this time, we estimate the cost of our compliance will be approximately $210 million to $260 million with the majority of the expenditures in the 2016-2023 timeframe. This estimate is reflected in our asset retirement obligations ("AROs").

Illinois CCR Rule. The IPCB extended its stay of the Illinois EPA's proposed rulemaking to June 2016.

Coal Segment Groundwater. Please read Note 13—Commitments and Contingencies, Other Contingencies, Coal Segment Groundwater, for further discussion.

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Asset Retirement Obligations

AROs are recorded as liabilities on our unaudited consolidated balance sheets at their Net Present Value (“NPV”) using interest rates ranging from 8.8 percent to 19.4 percent. The following table presents the NPV and projected obligation as of March 31, 2016:

		Projected Obligation by Period				
(amounts in millions)	NPV	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years	Total
Coal						
CCR	$120	$32	$ 38	$ 32	$ 39	$141
Non-CCR	55	—	17	5	112	134
Total Coal segment	175	32	55	37	151	275
Gas						
Non-CCR	29	15	3	—	45	63
Total Gas segment	29	15	3	—	45	63
IPH						
CCR	69	—	89	21	—	110
Non-CCR	12	5	4	27	76	112
Total IPH segment	81	5	93	48	76	222
Total Consolidated AROs	$285	$52	$ 151	$ 85	$ 272	$560

Coal Segment. At March 31, 2016, Coal segment CCR AROs consisted of projected expenditures of $141 million related to surface impoundments and groundwater monitoring. Non-CCR AROs consisted of projected expenditures of $96 million related to asbestos removal, $30 million related to surface impoundments and groundwater monitoring, and $8 million related to landfill closures.

Gas Segment. At March 31, 2016, Gas segment Non-CCR AROs consisted of projected expenditures of $37 million related to decommissioning, $11 million related to the South Bay demolition, $5 million related to asbestos removal, $4 million related to pipeline burial/removal, and $6 million related to other obligations.

IPH Segment. At March 31, 2016, IPH segment CCR AROs consisted of projected expenditures of $110 million related to surface impoundments and groundwater monitoring. Non-CCR AROs consisted of projected expenditures of $71 million related to asbestos removal, $30 million related to surface impoundments and groundwater monitoring, and $11 million related to landfill closures.

Climate Change

State Regulation of Greenhouse Gas (“GHG”)

California. The California Air Resources Board (“CARB”) and the Province of Québec held their sixth joint allowance auction in February 2016 with current vintage auction allowances selling at a clearing price of $12.73 per metric ton and 2019 auction allowances selling at a clearing price of $12.73 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 May 2016.

We estimate the cost of GHG allowances required to operate Moss Landing Units 1 and 2 in California during 2016 will be approximately $14 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. The tolling agreement for Moss Landing Units 6 and 7 provides that our counterparty is financially responsible for GHG allowances for these units.

RGGI. In March 2016, RGGI held its thirty-first auction, in which approximately 15 million allowances were sold at a clearing price of $5.25 per allowance. RGGI's next quarterly auction is scheduled for June 2016. We have participated in quarterly RGGI auctions or in secondary markets, as appropriate, to secure allowances for our affected assets.

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We estimate the cost of RGGI allowances required to operate our affected facilities in Connecticut, Maine, Massachusetts, and New York during 2016 will be approximately $45 million. We expect any future changes in the price of RGGI allowances to be reflected in both the forward and locational marginal prices for power and be neutral to our gross margins.

RISK MANAGEMENT DISCLOSURES

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

(amounts in millions)	As of and for the Three Months Ended March 31, 2016
Fair value of portfolio at December 31, 2015	$ (90)
Risk management gains recognized through the statement of operations in the period, net	91
Contracts realized or otherwise settled during the period	18
Changes in collateral/margin netting	(27)
Fair value of portfolio at March 31, 2016	$ (8)

The net risk management liability of $8 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 March 31, 2016, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total	2016	2017	2018	2019	2020	Thereafter
Market quotations (1)(2)	$(53)	$9	$(46)	$(9)	$(6)	$(1)	$ —
Prices based on models (2)	(34)	(24)	(4)	(8)	1	1	—
Total (3)	$(87)	$(15)	$(50)	$(17)	$(5)	$—	$ —

(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 $79 million of broker margin that has been netted against Risk management liabilities on our unaudited consolidated balance sheets. Please read Note 5—Risk Management Activities, Derivatives, and Financial Instruments for further discussion.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

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

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- 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;
- beliefs concerning the strategic review of Genco, including any debt restructuring;
- the timing and anticipated benefits to be achieved through our company-wide improvement programs, including our PRIDE initiative;
- anticipated timing, outcome, and impact of the expected retirement of Brayton Point and the shutdown of Baldwin Units 1 and 3 and Newton Unit 2;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the Vermilion and Wood River facilities and any potential future remediation obligations at the South Bay facility;
- expectations regarding the financing, synergies, completion, timing, terms, and anticipated benefits of the Delta Transaction; 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.

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 March 31, 2016.

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Value at Risk ("VaR"). The following table sets forth the aggregate daily VaR of the mark-to-market portion of our risk management portfolio primarily associated with the Coal and Gas segments. The VaR calculation does not include market risks associated with the accrual portion of the risk management portfolio that is designated as "normal purchase, normal sale," nor does it include expected future production from our generating assets. Please read "VaR" in our Form 10-K for a complete description of our valuation methodology. The daily VaR at March 31, 2016 compared to December 31, 2015 was lower due to a decrease in volatility and price.

Daily and Average VaR for Risk Management Portfolios

(amounts in millions)	March 31, 2016	December 31, 2015
One day VaR—95 percent confidence level	$ 9	$ 20
One day VaR—99 percent confidence level	$ 13	$ 29
Average VaR—95 percent confidence level for the rolling twelve months ended	$ 10	$ 8

Credit Risk. The following table represents our credit exposure at March 31, 2016 associated with the mark-to-market portion of our risk management portfolio, on a net basis. We had exposure of less than $1 million related to non-investment grade quality counterparties.

Credit Exposure Summary

(amounts in millions)	Investment Grade Quality
Type of Business:	
Financial institutions	$ 71
Oil and gas producers	4
Utility and power generators	21
Commercial/industrial/end users	2
Total	$ 98

Interest Rate Risk

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

The absolute notional amounts associated with our interest rate contracts were as follows at March 31, 2016 and December 31, 2015, respectively:

	March 31, 2016	December 31, 2015
Interest rate swaps (in millions of U.S. dollars)	$ 775	$ 777
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 March 31, 2016.

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 March 31, 2016.

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PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS

Please read Note 13—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 below and Item 1A—Risk Factors of our Form 10-K for factors, risks, and uncertainties that may affect future results.

We may be unable to obtain the regulatory approvals required to complete the Delta Transaction or, in order to do so, we may be required to comply with material restrictions on our conduct or satisfy other material conditions required by various regulatory authorities.

Consummation of the Delta Transaction is subject to conditions and governmental approvals, including approval from the FERC and the Public Utility Commission of Texas and the expiration or termination of the waiting period applicable to the Delta Transaction under the Hart-Scott-Rodino Antitrust Improvements (“HSR”) Act. The closing of the Delta Transaction is also subject to the condition that there be no injunction or order issued by a governmental authority that restrains, enjoins, or otherwise prohibits the consummation of the transactions contemplated by the Delta Stock Purchase Agreement. The waiting period applicable to the Delta Transaction under the HSR Act has been terminated, but we can provide no assurance that all other required regulatory approvals will be obtained. There can also be no assurance as to the cost, scope, or impact of the actions that may be required to obtain the required regulatory approvals. Furthermore, these actions could have the effect of delaying or preventing completion of the Delta Transaction or imposing additional costs, conditions, or restrictions on our business and operations, some of which could be material and adversely affect our revenues and profitability following the consummation of the transaction.

Furthermore, the FERC, the Public Utility Commission of Texas, the Department of Justice, or other governmental authorities could seek to block or challenge the Delta Transaction as they deem necessary or desirable in the public interest at any time, including after completion of the transaction. In addition, in some circumstances, a competitor, customer, or other third party could initiate a private action under antitrust laws challenging or seeking to enjoin the Delta Transaction, before or after it is consummated. We may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

If the Delta Transaction is consummated, we may be unable to successfully integrate the operations of the assets with our existing operations or to realize targeted cost savings, revenues and other anticipated benefits of the transaction.

The success of the Delta Transaction will depend, in part, on our ability to realize the anticipated benefits and synergies from integrating GSENA’s assets with our existing generation business. To realize these anticipated benefits, the businesses must be successfully combined.

We may be required to make unanticipated capital expenditures or investments in order to maintain, integrate, improve or sustain the assets’ operations, or take unexpected write-offs or impairment charges resulting from the transaction. Further, we may be subject to unanticipated or unknown liabilities relating to the assets. If any of these factors occur or limit our ability to integrate the businesses successfully or on a timely basis, the expectations of our future financial conditions and results of operations following the transaction might not be met.

In addition, we and GSENA have operated and, until the consummation of the transaction, will continue to operate independently. It is possible that the integration process could result in the loss of key employees, the disruption of each company’s ongoing businesses, inefficiencies, or inconsistencies in standards, controls, information technology systems, procedures, and policies, any of which could adversely affect our ability to achieve the anticipated benefits of the transaction and could harm our financial performance. Further, we may be required to implement or improve the internal controls, procedures, and policies of the assets to meet standards applicable to U.S. public companies, which may be time-consuming and more expensive than anticipated.

In addition, we continue to evaluate our estimates of synergies to be realized from, and the fair value accounting allocations associated with, the Delta Transaction and refine them. Accordingly, actual cost-savings, the costs required to realize the cost-savings, and the source of the cost-savings could differ materially from our estimates, and we cannot assure you that we will achieve the full amount of cost-savings on the schedule anticipated or at all.

Finally, we may not be able to achieve the targeted operating or long-term strategic benefits of the Delta Transaction. If the combined businesses are not able to achieve our objectives, or are not able to achieve our objectives on a timely basis, the anticipated benefits of the transaction may not be realized fully or at all. An inability to realize the full extent of, or any of, the

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anticipated benefits of the transaction, as well as any delays encountered in the integration process, could have an adverse effect on our financial condition, results of operations, and cash flows.

We will incur significant transaction and acquisition-related costs in connection with the Delta Transaction.

We expect to incur significant costs associated with the Delta Transaction and combining the operations of our company with GSENA, including costs to achieve targeted cost-savings. The substantial majority of the expenses resulting from the transaction will be composed of transaction costs, systems consolidation costs, and business integration and employment-related costs, including costs for severance, retention, and other restructuring. We may also incur transaction fees and costs related to formulating integration plans. Additional unanticipated costs may be incurred in the integration of our and the GSENA businesses. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow us to offset incremental transaction and acquisition-related costs over time, this net benefit may not be achieved in the near term, or at all.

Failure to consummate the Delta Transaction could negatively impact the market price of our common stock and cause us to incur significant costs that could materially impact our financial performance, results of operations, or financial condition.

There can be no assurance that the Delta Transaction will be consummated. Failure to consummate the Delta Transaction may negatively impact the future trading price of our common stock, and if the Delta Transaction is not consummated, the market price of our common stock may decline to the extent that the current market price of our common stock reflects a market assumption that there is a high probability that the Delta Transaction will be consummated. In addition, if the Delta Stock Purchase Agreement is terminated under certain circumstances, the Delta Stock Purchase Agreement requires the Purchaser to pay GSENA a fee of $132 million, of which we would be obligated to fund $85.8 million. Payment of such termination fee could materially and adversely impact our results of operations or financial condition.

The announcement and pendency of the acquisitions could impact or cause disruptions in our and GSENA’s operations.

The announcement and pendency of the Delta Transaction could impact or cause disruptions in our, and GSENA’s operations. Specifically:

- our and GSENA’s current and prospective customers and suppliers may experience uncertainty associated with the transaction, including with respect to current or future business relationships with us and GSENA or the combined company business and may attempt to negotiate changes in existing business;
- our and GSENA’s employees may experience uncertainty about their future roles with us, which may adversely affect our and GSENA’s ability to retain and hire key employees; and
- the transaction may give rise to potential liabilities, including potential stockholder lawsuits relating to the transaction.

Any of the above disruptions could have an adverse effect on our business, results of operations, and financial condition.

If the Delta Transaction is consummated, we will conduct a portion of our operations through a joint venture, which will subject these operations to additional risks that could have a material adverse effect on their success and on our financial position and results of operations.

If the Delta Transaction is consummated, we will conduct a portion of our operations through Atlas Power, a joint venture with the ECP Funds. The Atlas Power joint venture arrangement may present financial, managerial, and operational challenges, including potential disputes, liabilities, and contingencies, and may involve risks not otherwise present when operating assets directly, including, for example:

- our joint venture partner may have business interests or goals that are or may become inconsistent with our business interests or goals;
- our joint venture partner shares certain approval rights over major decisions;
- we may be unable in certain circumstances to control the amount of cash we will receive from Atlas Power;
- we may incur liabilities as a result of an action taken by Atlas Power or our joint venture partner;
-

- we may be required to devote significant management time to the requirements of and matters relating to Atlas Power; and
- disputes between us and our joint venture partner may result in delays, litigation or operational impasses.

The challenges and risks described above could adversely affect Atlas Power's ability to transact its business, which would in turn negatively affect Atlas Power's financial condition, results of operations, and distributable cash flows. Any such negative effects could have an adverse effect on our financial condition and results of operations.

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If the Delta Transaction is consummated, Atlas Power will be financed primarily through non-recourse project finance debt. If Atlas Power defaults on its obligations under such non-recourse debt, we may decide to make certain payments to the relevant debt holders to prevent foreclosure, which would, without such payments, cause us to lose our ownership interest in Atlas Power or in some or all of its power generation facilities.

If the Delta Transaction is consummated, Atlas Power will be financed primarily through non-recourse project finance debt. Non-recourse project finance debt refers to financing arrangements that are repaid solely from the project's revenues and are secured by the project's physical assets, major contracts, cash accounts, and, in many cases, the project owners' ownership interests in the project. If Atlas Power defaults on its obligations under its non-recourse financing agreements, we may decide to make payments to prevent the debt holders from foreclosing on Atlas Power's collateral. Such a foreclosure would result in our losing our ownership interests or in some or all of its power generation facilities. The loss of our ownership interests, or some or all of its assets, or our decision to make payments to lenders to avoid any such loss, could have a material adverse effect on our business, financial condition, and results of operations.

If the PIPE Transaction is consummated, Terawatt will own approximately 15% of our common stock and may exert influence over matters requiring Board of Directors and/or stockholder approval.

If the PIPE Transaction is consummated, Terawatt will beneficially own approximately 15% of the outstanding shares of our common stock and will have the right to appoint one member to our Board of Directors. As a result, Terawatt may be able to exercise influence over matters requiring approval by our Board of Directors and our stockholders. The interests of Terawatt may conflict with the interests of our other stockholders. Terawatt may have an interest in having us pursue, or not pursue, acquisitions, divestitures, and other transactions that, in its judgment, could enhance its investment in us, even though such transactions might involve benefits or risks to other stockholders.

In addition, Terawatt and its affiliates engage in a broad spectrum of activities, including investments in the power generation industry. In the ordinary course of their business activities, Terawatt and its affiliates may engage in activities where their interests conflict with our interests or those of our stockholders. Further, Dynegy has agreed to renounce any interest in a corporate or business opportunity taken by Terawatt or its affiliates, unless such corporate or business opportunity is offered to the member of our Board of Directors appointed by Terawatt in his or her capacity as a director of Dynegy.

Item 6—EXHIBITS

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

Exhibit Number	Description
2.1	Stock Purchase Agreement, dated February 24, 2016, by and between Atlas Power Finance, LLC, GDF SUEZ Energy North America, Inc. and International Power, S.A.* (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 1, 2016 File No. 001-33443).
**2.2	First Amendment Stock Purchase Agreement, dated May 2, 2016, by and between Atlas Power Finance, LLC, GDF SUEZ Energy North America, Inc. and International Power, S.A.*.
10.1	Form of Performance Award Agreement (2016 Awards) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 14, 2016 File No. 001-33443).
10.2	Form of Performance Award Agreement (CEO) (2016 Awards) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on March 14, 2016 File No. 001-33443).
10.3	Form of Stock Unit Award Agreement (Executive Management) (2016 Awards) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 14, 2016 File No. 001-33443).
10.4	Form of Stock Unit Award Agreement (CEO) (2016 Awards) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on March 14, 2016 File No. 001-33443).
10.5	Form of Non-Qualified Stock Option Award Agreement (2016 Awards) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 14, 2016 File No. 001-33443).
10.6	Form of Non-Qualified Stock Option Award Agreement (CEO) (2016 Awards) (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc. filed on March 14, 2016 File No. 001-33443).
10.7	Equity Commitment Letter, dated as of February 24, 2016, by and among Dynegy Inc., Atlas Power, LLC and Atlas Power Finance, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 1, 2016 File No. 001-33443).
10.8	Equity Commitment Letter, dated as of February 24, 2016, by and among Energy Capital Partners III, LP, Energy Capital Partners III-A, LP, Energy Capital Partners III-B, LP, Energy Capital Partners III-C, LP, Energy Capital Partners III-D, LP, Atlas Power, LLC and Atlas Power Finance, LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on March 1, 2016 File No. 001-33443).
10.9	Limited Guarantee, dated February 24, 2016, by Dynegy Inc., for the benefit of GDF SUEZ Energy North America, Inc. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 1, 2016 File No. 001-33443).
10.10	Stock Purchase Agreement, dated February 24, 2016, by and between Dynegy Inc. and Terawatt Holdings, LP (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on March 1, 2016 File No. 001-33443).
10.11	Interim Sponsors Agreement, dated February 24, 2016, by and between Atlas Power, LLC, Dynegy Inc., Energy Capital Partners III, LP, Energy Capital Partners III-A, LP, Energy Capital Partners III-B, LP,

	Energy Capital Partners III-C, LP and Energy Capital Partners III-D, LP (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 1, 2016 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

** Filed herewith.

* Schedules and exhibits to the Stock Purchase Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Dynegy will furnish the omitted schedules and exhibits to the Securities and Exchange Commission upon request by the Commission.

† 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:	May 4, 2016	By:	/s/ CLINT C. FREELAND
			Clint C. Freeland
			Executive Vice President and Chief Financial Officer