DYNEGY INC.
Form 10-Q
August 04, 2017
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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 June 30, 2017

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, a smaller reporting company, or an emerging growth company. See definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company” and “emerging growth 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)	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

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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 ¨

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, 131,372,747 shares outstanding as of July 13, 2017.

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DEFINITIONS

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

ATSI	American Transmission Service, Inc.
CAA	Clean Air Act
CAISO	The California Independent System Operator
CDD	Cooling Degree Days
COMED	Commonwealth Edison
CPUC	California Public Utility Commission
CT	Combustion Turbine
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EMAAC	Eastern Mid-Atlantic Area Council
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
HDD	Heating Degree Days
IMA	In-market Asset Availability
IPH	IPH, LLC
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LIBOR	London Interbank Offered Rate
MAAC	Mid-Atlantic Area Council
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	One Million British Thermal Units
Moody’s	Moody’s Investors Service Inc.
MW	Megawatts
MWh	Megawatt Hour
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PPL	PPL Electric Utilities, Corp.
PRIDE	Producing Results through Innovation by Dynegy Employees
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional Transmission Organization
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)

	June 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents	$447	$ 1,776
Restricted cash	—	62
Accounts receivable, net of allowance for doubtful accounts of $1 and $1, respectively	441	386
Inventory	477	445
Assets from risk management activities	83	130
Intangible assets	23	38
Prepayments and other current assets	119	150
Total Current Assets	1,590	2,987
Property, plant and equipment, net	9,485	7,121
Investment in unconsolidated affiliate	150	—
Restricted cash	—	2,000
Assets from risk management activities	46	16
Goodwill	799	799
Intangible assets	58	23
Assets held-for-sale	463	—
Other long-term assets	168	107
Total Assets	$12,759	$ 13,053

See the notes to consolidated financial statements.

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

	June 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$370	$ 332
Accrued interest	116	81
Intangible liabilities	25	21
Accrued liabilities and other current liabilities	154	133
Liabilities from risk management activities	73	97
Asset retirement obligations	59	51
Debt, current portion, net	106	201
Total Current Liabilities	903	916
Liabilities subject to compromise (Note 18)	—	832
Debt, long-term portion, net	9,211	8,778
Liabilities from risk management activities	48	43
Asset retirement obligations	246	236
Deferred income taxes	30	5
Intangible liabilities	41	34
Other long-term liabilities	161	170
Total Liabilities	10,640	11,014
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; 142,691,801 shares issued and 131,365,679 shares outstanding at June 30, 2017; 128,626,740 shares issued and 117,300,618 outstanding at December 31, 2016	1	1
Additional paid-in capital	3,320	3,547
Accumulated other comprehensive income, net of tax	28	21
Accumulated deficit	(1,626)	(1,927)
Total Dynegy Stockholders' Equity	2,123	2,042
Noncontrolling interest	(4)	(3)
Total Equity	2,119	2,039
Total Liabilities and Equity	$12,759	$ 13,053

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 June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Revenues	$1,164	$904	$2,411	$2,027
Cost of sales, excluding depreciation expense	(681)	(493)	(1,438)	(1,038)
Gross margin	483	411	973	989
Operating and maintenance expense	(282)	(256)	(514)	(477)
Depreciation expense	(209)	(160)	(409)	(331)
Impairments	(99)	(645)	(119)	(645)
Loss on sale of assets, net	(29)	—	(29)	—
General and administrative expense	(42)	(39)	(82)	(76)
Acquisition and integration costs	(7)	3	(52)	(1)
Other	3	(16)	1	(16)
Operating loss	(182)	(702)	(231)	(557)
Bankruptcy reorganization items (Note 18)	(1)	—	482	—
Earnings from unconsolidated investments	1	1	—	3
Interest expense	(159)	(141)	(326)	(283)
Other income and expense, net	29	30	46	31
Loss before income taxes	(312)	(812)	(29)	(806)
Income tax benefit (expense) (Note 14)	16	9	329	(7)
Net income (loss)	(296)	(803)	300	(813)
Less: Net loss attributable to noncontrolling interest	—	(2)	(1)	(2)
Net income (loss) attributable to Dynegy Inc.	(296)	(801)	301	(811)
Less: Dividends on preferred stock	6	6	11	11
Net income (loss) attributable to Dynegy Inc. common stockholders	$(302)	$(807)	$290	$(822)
Earnings (Loss) Per Share (Note 16):				
Basic earnings (loss) per share attributable to Dynegy Inc. common stockholders	$(1.96)	$(6.73)	$1.91	$(6.97)
Diluted earnings (loss) per share attributable to Dynegy Inc. common stockholders	$(1.96)	$(6.73)	$1.76	$(6.97)
Basic shares outstanding	154	120	152	118
Diluted shares outstanding	154	120	171	118

See the notes to consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net income (loss)	$(296)	$(803)	$300	$(813)
Other comprehensive income (loss) before reclassifications:				
Actuarial gain and plan amendment (net of tax of $4, zero, $4, and zero for each respective period)	(4)	—	11	—
Amounts reclassified from accumulated other comprehensive income:				
Amortization of unrecognized prior service credit (net of tax of zero for each respective period)	(2)	(1)	(4)	(2)
Other comprehensive income (loss), net of tax	(6)	(1)	7	(2)
Comprehensive income (loss)	(302)	(804)	307	(815)
Less: Comprehensive loss attributable to noncontrolling interest	—	(2)	(1)	(2)
Total comprehensive income (loss) attributable to Dynegy Inc.	$(302)	$(802)	$308	$(813)

See the notes to consolidated financial statements.

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

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$300	$(813)
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Depreciation expense	409	331
Non-cash interest expense	32	23
Amortization of intangibles	15	13
Risk management activities	(1)	(89)
Loss on sale of assets, net	29	—
Earnings from unconsolidated investments	—	(3)
Deferred income taxes	(329)	7
Impairments	119	645
Change in value of common stock warrants	(15)	(2)
Bankruptcy reorganization items	(482)	—
Other	29	18
Changes in working capital:		
Accounts receivable, net	(13)	15
Inventory	76	77
Prepayments and other current assets	44	156
Accounts payable and accrued liabilities	17	8
Changes in non-current assets	(1)	(12)
Changes in non-current liabilities	1	1
Net cash provided by operating activities	230	375
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(86)	(286)
Acquisitions, net of cash acquired	(3,263)	—
Distributions from unconsolidated investments	2	8
Other investing	1	7
Net cash used in investing activities	(3,346)	(271)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of debt issuance costs	425	2,278
Repayments of borrowings	(331)	(20)
Proceeds from issuance of equity, net of issuance costs	150	362
Preferred stock dividends paid	(11)	(11)
Interest rate swap settlement payments	(9)	(9)
Acquisition of noncontrolling interest	(375)	—
Payments related to bankruptcy settlement	(123)	—
Other financing	(1)	(2)
Net cash provided by (used in) financing activities	(275)	2,598
Net increase (decrease) in cash, cash equivalents and restricted cash	(3,391)	2,702
Cash, cash equivalents and restricted cash, beginning of period	3,838	544
Cash, cash equivalents and restricted cash, end of period	$447	$3,246

See the notes to consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2017 and 2016

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, 2016, filed with the SEC on February 24, 2017, 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.

We sell electric energy, capacity and ancillary services primarily on a wholesale basis from our power generation facilities. We also serve residential, municipal, commercial and industrial customers primarily in MISO and PJM through our Homefield Energy and Dynegy Energy Services retail businesses. We report the results of our power generation business as six segments in our unaudited consolidated financial statements: (i) PJM, (ii) ISO-NE/NYISO ("NY/NE"), (iii) ERCOT, (iv) MISO, (v) IPH, and (vi) CAISO. 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.

On February 2, 2017 (the "Emergence Date"), Illinois Power Generating Company ("Genco") emerged from bankruptcy. Please read Note 18—Genco Chapter 11 Bankruptcy and Emergence for further discussion.

Note 2—Accounting Policies

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 GAAP. Except for the adoption of new policies as described below, there have been no significant changes to our accounting policies during the six months ended June 30, 2017.

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.

Accounting Standards Adopted

Statement of Cash Flows. In August 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-15-Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments. To reduce current and future diversity in practice, the amendments in this ASU provide guidance for several cash flow classification issues identified where current GAAP is either unclear or does not include specific guidance. We adopted this ASU on January 1, 2017 and applied the amendments on a retrospective basis. The adoption of this ASU affected the classification of prepayments for future planned outage work performed under long-term service agreements. The majority of the cash prepayments required under these agreements will now be reflected as cash outflows from investing activities and the remainder will be classified as cash outflows from operating activities, based on whether they are anticipated to be expensed or capitalized. As a result of the retrospective application of this ASU, we reclassified approximately $62 million of cash prepayments from operating activities to investing activities in our unaudited consolidated statement of cash flows for the six months ended June 30, 2016.

In November 2016, the FASB issued ASU 2016-18-Statement of Cash Flows (Topic 230): Restricted Cash. The amendments in this ASU require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2017 and 2016

described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. We adopted this ASU as of January 1, 2017 and applied the amendments on a retrospective basis. As a result of the retrospective application of this ASU, changes in restricted cash of $4 million and $2.069 billion previously reflected as cash flows from operating activities and investing activities, respectively, are now reflected in Net increase (decrease) in cash, cash equivalents, and restricted cash in our unaudited consolidated statement of cash flows for the six months ended June 30, 2016. Additionally, restricted cash of $39 million and $2.104 billion are now reflected in the beginning of period and end of period cash, cash equivalents and restricted cash line items, respectively, in our unaudited consolidated statement of cash flows for the six months ended June 30, 2016. Please read Note 7—Cash Flow Information for further discussion.

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. We adopted this ASU on January 1, 2017 with no material impact on our unaudited consolidated financial statements.

Goodwill. In January 2017, the FASB issued ASU 2017-04-Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment. To simplify the subsequent measure of goodwill, the amendments in this ASU eliminate step two from the goodwill impairment test. An entity will no longer be required to calculate the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if the reporting unit had been acquired in a business combination to determine the impairment of goodwill. The amendments in this ASU will now require goodwill impairment to be measured by the amount by which the carrying value of the reporting unit exceeds its fair value. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Upon adoption, an entity shall apply the guidance in this ASU prospectively with early adoption permitted for annual goodwill tests performed after January 1, 2017. We adopted this ASU on January 1, 2017 with no material impact on our unaudited consolidated financial statements.

Accounting Standards Not Yet Adopted

Financial Instruments with Down Round Features. In July 2017, the FASB issued ASU 2017-11, Earnings Per Share (Topic 260); Distinguishing Liabilities from Equity (Topic 480); Derivatives and Hedging (Topic 815): Accounting for Certain Financial Instruments with Down Round Features. The amendments of this ASU update the classification analysis of certain equity-linked financial instruments, or embedded features, with down round features, as well as clarify existing disclosure requirements for equity-classified instruments. When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock. The guidance in this ASU is effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020, with early adoption permitted. We are currently evaluating this ASU and any potential impacts the adoption will have on our unaudited consolidated financial statements.

Business Combinations. In January 2017, the FASB issued ASU 2017-01-Business Combinations (Topic 805): Clarifying the Definition of a Business. The amendments in this ASU clarify the definition of a business. The amendments affect all companies and other reporting organizations that must determine whether they have acquired or sold a business. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, with early adoption permitted. We are currently evaluating this ASU and any potential impacts the adoption will have on our unaudited consolidated financial statements.

Pensions. In March 2017, the FASB issued ASU No. 2017-07, Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. The amendments of this ASU require an entity to report the service cost component of net benefit costs in the same line item as other compensation costs arising from services rendered by the related employees during the applicable service period. The other components of net benefit cost are required to be presented separately from the service cost component and below the subtotal of operating income. Additionally, only the service cost component of net benefit costs is eligible for capitalization. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, with early adoption permitted. The adoption of this standard must be applied on a retrospective basis for the amendments concerning income statement presentation and on a prospective basis for the amendments regarding the capitalization of the service cost component. We are currently evaluating this ASU and any potential impacts the adoption will have on our unaudited consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2017 and 2016

Leases. In February 2016, the FASB issued ASU 2016-02-Leases (Topic 842). The provisions in this ASU will require lessees to recognize lease assets and lease liabilities, for all leases, including operating leases, on the 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 based on the present value of the minimum rental payments. Entities may make an accounting policy election to not recognize lease assets or lease liabilities for leases with a term of 12 months or less. The guidance in this ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. We are currently evaluating this ASU and any potential impacts the adoption will have on our unaudited consolidated financial statements.

Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09-Revenue from Contracts with Customers (Topic 606). This ASU supersedes current revenue recognition requirements and industry specific guidance and develops a common revenue recognition standard whereby an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing, and uncertainty of revenues and cash flows from contracts with customers. The guidance in this ASU and its amendments are 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 have established an implementation team to assess the impact the new accounting standard will have on our financial statements upon adoption and have not currently identified any material changes to the timing of our revenue recognition. We continue to assess the impact of the standard by reviewing our revenue contracts to determine if changes in our recognition policies or controls are necessary. We believe changes to our disclosures will primarily include a regional presentation of our revenues disaggregated by revenue type - energy, capacity, and ancillary services.

Note 3—Acquisitions and Divestitures

Acquisition

ENGIE Acquisition. On February 7, 2017 (the "ENGIE Acquisition Closing Date"), pursuant to the terms of the stock purchase agreement, as amended and restated on June 27, 2016, (the "ENGIE Acquisition Stock Purchase Agreement"), Dynegy acquired approximately 9,017 MW of generation from GDF SUEZ Energy North America, Inc. ("GSENA") and International Power, S.A. (the "Seller"), including (i) 15 natural gas-fired facilities located in Illinois, Massachusetts, New Jersey, Ohio, Pennsylvania, Texas, Virginia, and West Virginia, (ii) one coal-fired facility in Texas, and (iii) one waste coal-fired facility in Pennsylvania for a base purchase price of approximately $3.3 billion in cash, subject to certain adjustments (the "ENGIE Acquisition").

Business Combination Accounting. The ENGIE Acquisition has been accounted for in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date, February 7, 2017. A summary of the various techniques used to fair value the identifiable assets and liabilities, as well as their classification within the fair value hierarchy are listed below.

- Working capital was valued using available market information (Level 2).
- Acquired property, plant and equipment ("PP&E"), excluding those assets classified as held-for-sale, was valued using a discounted cash flow ("DCF") analysis based upon a debt-free, free cash flow model (Level 3). The DCF model was created for each power generation facility based on its remaining useful life, and:

for the years 2017 and 2018, included gross margin forecasts using quoted forward commodity market prices;
for the years 2019 through 2026, 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 2026, we assumed a 2.5 percent growth rate.

We also used management’s forecasts of operations and maintenance expense, general and administrative expense, as well as capital expenditures for the years 2017 through 2021, and for years thereafter assumed a 2.5 percent growth rate. These cash flows were discounted using discount rates of approximately 9 percent to 13 percent for gas-fired, and approximately 13 percent to 14 percent for coal-fired, generation facilities, based upon the plant’s age, efficiency, region, and years until retirement.

- Acquired PP&E classified as held-for-sale was valued based upon the sale price of the assets (Level 2).

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2017 and 2016

- Acquired derivatives were valued using the methods described in Note 6—Fair Value Measurements (Level 2 or Level 3).
- Contracts with terms that were not at current market prices were also valued using a DCF analysis (Level 3). 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.
- Asset retirement obligations ("AROs") were recorded in accordance with ASC 410, Asset Retirement and Environmental Obligations (Level 3).

The accounting for the ENGIE Acquisition 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 first quarter of 2018. The significant assets and liabilities for which provisional amounts are recognized are PP&E, deferred income taxes and taxes other than deferred income taxes. 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 or deferred tax liability. As such, the provisional amounts recognized are subject to revision until our valuation is completed, not to exceed one year from the ENGIE Acquisition Closing Date, and any material adjustments identified that existed as of the acquisition date will be recognized in the period in which they are identified.

The following table summarizes the consideration paid and the provisional fair value amounts recognized for the assets acquired and liabilities assumed related to the ENGIE Acquisition, as of the acquisition date, February 7, 2017:

(amounts in millions)	
Base purchase price	$3,300
Working capital adjustments and other	(31)
Fair value of total consideration transferred	$3,269
Cash	$20
Accounts receivable	22
Inventory	101
Prepayments and other current assets	3
Assets from risk management activities (including current portion of $21 million)	25
Property, plant and equipment	2,756
Investment in unconsolidated affiliate	152
Intangible assets (including current portion of $7 million)	50
Assets held-for-sale	445
Other long-term assets	131
Total assets acquired	3,705
Accounts payable	28
Liabilities from risk management activities (including current portion of $13 million)	16
Asset retirement obligations	19
Intangible liabilities (including current portion of $16 million)	30
Deferred income taxes, net	342
Other long-term liabilities	1
Total liabilities assumed	436
Net assets acquired	$3,269

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2017 and 2016

The following table summarizes certain information related to the ENGIE Acquisition, which is included in our unaudited consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
(amounts in millions)	2017	2016	2017	2016
Acquisition costs	$4	$ —	$35	$ 2
Revenues	$246	N/A	$324	N/A
Operating income	$20	N/A	$4	N/A

Pro Forma Results. The unaudited pro forma financial results for the six months ended June 30, 2017 and 2016 assume the ENGIE Acquisition occurred on January 1, 2016. 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, 2016, nor are they indicative of future results of operations. The unaudited pro forma financial results for the six months ended June 30, 2017 and 2016 include adjustments of $35 million and $2 million, respectively, for non-recurring acquisition costs attributable to the ENGIE Acquisition.

	Six Months Ended June 30,	
(amounts in millions)	2017	2016
Revenue	$2,468	$2,315
Net income (loss)	$302	$(948)
Net income (loss) attributable to Dynegy Inc.	$303	$(946)

AER Acquisition. On April 12, 2017, we received approximately $25 million of cash related to the 2013 AER Acquisition. As a result, we have recorded $25 million in Other income and expense, net in our unaudited consolidated statement of operations.

Divestitures

On July 11, 2017, Dynegy completed the sale of its equity ownership interests in two peaking facilities in PJM to LS Power (the “Troy and Armstrong Sale”) for approximately $480 million in cash, plus adjustments for capital expenditures and working capital. The facilities sold were recently acquired in the ENGIE Acquisition and total 1,269 MW. The proceeds are to be allocated to debt reduction.

The Troy and Armstrong facilities are classified as long-term assets held-for-sale as of June 30, 2017 and are presented below, in millions:

Inventory	$11
Property, plant & equipment	452
Assets held-for-sale	$463

Note 4—Unconsolidated Investments

Equity Method Investments

NELP. In connection with the ENGIE Acquisition, we acquired a 50 percent interest in Northeast Energy, LP (“NELP”), a joint venture with NextEra Energy, Inc., which indirectly owns the Bellingham NEA facility and the Sayreville facility. At June 30, 2017, our equity method investment in NELP included in our unaudited consolidated balance sheets was $150 million. Upon the acquisition, we recognized basis differences in the net assets of approximately $14 million related to PP&E. 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.

For the three and six months ended June 30, 2017, we recorded $1 million and less than $1 million in equity earnings, respectively, related to our investment in NELP which is reflected in Earnings from unconsolidated investments in our unaudited consolidated statements of operations. For the six months ended June 30, 2017, we received a distribution of $2 million, all of which was considered to be a return of investment using the cumulative earnings approach and reflected as Distributions from unconsolidated investments in our unaudited consolidated statements of cash flows.

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Elwood. On November 21, 2016, Dynegy sold its 50 percent equity interest in Elwood Energy, LLC, a limited liability company (“Elwood Energy”) and Elwood Expansion LLC, a limited liability company (and together with Elwood Energy “Elwood”), to J-Power USA Development Co. Ltd. for approximately $173 million (the “Elwood Sale”).
For the three and six months ended June 30, 2016, we recorded $1 million and $3 million, respectively, in equity earnings related to our investment in Elwood which is reflected in Earnings from unconsolidated investments in our unaudited consolidated statements of operations. For the six months ended June 30, 2016, we received distributions of $8 million, all of which was considered to be a return of investment using the accumulated earnings approach and reflected as Distributions from unconsolidated investments in our unaudited consolidated statements of cash flows.

Note 5—Risk Management Activities, Derivatives and Financial Instruments

The nature of our business 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.

Quantitative Disclosures Related to Financial Instruments and Derivatives

As of June 30, 2017, 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)	(65)	MWh	$ 40
Electricity basis derivatives (3)	(46)	MWh	$ (9)
Natural gas derivatives (2)	410	MMBtu	$ (17)
Natural gas basis derivatives	135	MMBtu	$ (15)
Physical heat rate derivatives	142/(15)	MMBtu/MWh	$ (11)
Emissions derivatives	14	Metric Ton	$ (8)
Interest rate swaps	1,965	U.S. Dollar	$ (18)
Common stock warrants (4)	24	Warrant	$ (3)

(1) Includes both asset and liability risk management positions but excludes margin and collateral netting of $46 million.
(2) Mainly comprised of swaps and physical forwards.
(3) Comprised of FTRs and swaps.
(4) Each warrant is convertible into one share of Dynegy common stock.

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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 June 30, 2017 and December 31, 2016. As of June 30, 2017 and December 31, 2016, there were no gross amounts available to be offset that were not offset in our unaudited consolidated balance sheets.

		June 30, 2017			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$300	$(182)	$ —	$118
Interest rate contracts	Assets from risk management activities	11	—	—	11
Total derivative assets		$311	$(182)	$ —	$129
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(320)	$182	$ 46	$(92)
Interest rate contracts	Liabilities from risk management activities	(29)	—	—	(29)
Common stock warrants	Accrued liabilities and other current liabilities and other long-term liabilities	(3)	—	—	(3)
Total derivative liabilities		$(352)	$182	$ 46	$(124)
Total derivatives		$(41)	$—	$ 46	$5

		December 31, 2016			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$311	$(165)	$ —	$146
Total derivative assets		$311	$(165)	$ —	$146
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(329)	$165	$ 54	$(110)
Interest rate contracts	Liabilities from risk management activities	(30)	—	—	(30)
Common stock warrants	Accrued liabilities and other current liabilities	(1)	—	—	(1)

Total derivative liabilities	$(360)	$165	$ 54	$(141)
Total derivatives	$(49)	$—	$ 54	$5

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 worsen, 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. As of June 30, 2017, the aggregate fair value of all commodity derivative instruments containing credit-risk-related contingent features, in a liability position and not fully collateralized, is $15 million for which we have posted no collateral. Transactions with our clearing brokers are excluded as they are fully collateralized. 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 June 30, 2017 and December 31, 2016, within Prepayments and other current assets in our unaudited consolidated balance sheets and the amount applied against short-term risk management activities:

Location on Balance Sheet	June 30, 2017	December 31, 2016
(amounts in millions)		
Gross collateral posted with counterparties	$ 80	$ 116
Less: Collateral netted against risk management liabilities	46	54
Net collateral within Prepayments and other current assets	$ 34	$ 62

Impact of Derivatives on the Unaudited Consolidated Statements of Operations

We elect not to designate derivatives related to our power generation business and interest rate instruments as cash flow or fair value hedges. Thus, we account for changes in the fair value of these derivatives within our unaudited consolidated statements of operations.

Our unaudited consolidated statements of operations for the three and six months ended June 30, 2017 and 2016 include the impact of derivative financial instruments as presented below:

Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30,		Six Months Ended June 30,	
		2017	2016	2017	2016
(amounts in millions)					
Commodity contracts	Revenues	$29	$23	$213	$215
Interest rate contracts	Interest expense	$1	$(4)	$3	$(12)
Common stock warrants	Other income and (expense), net	$3	$—	$15	$1

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.

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The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2017 and December 31, 2016, and are presented on a gross basis before consideration of amounts netted under master netting agreements and the application of collateral and margin paid:

	Fair Value as of June 30, 2017			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$195	$15	$210
Natural gas derivatives	—	66	9	75
Physical heat rate derivatives	—	13	—	13
Emissions derivatives	—	2	—	2
Total assets from commodity risk management activities	—	276	24	300
Assets from interest rate contracts	—	11	—	11
Total assets	$—	$287	$24	$311
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(163)	$(16)	$(179)
Natural gas derivatives	—	(99)	(8)	(107)
Physical heat rate derivatives	—	(22)	(2)	(24)
Emissions derivatives	—	(10)	—	(10)
Total liabilities from commodity risk management activities	—	(294)	(26)	(320)
Liabilities from interest rate contracts	—	(29)	—	(29)
Liabilities from outstanding common stock warrants	(3)	—	—	(3)
Total liabilities	$(3)	$(323)	$(26)	$(352)

	Fair Value as of December 31, 2016			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$118	$20	$138
Natural gas derivatives	—	169	4	173
Total assets from commodity risk management activities	$—	$287	$24	$311
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(245)	$(12)	$(257)
Natural gas derivatives	—	(52)	(10)	(62)
Emissions derivatives	—	(10)	—	(10)
Total liabilities from commodity risk management activities	—	(307)	(22)	(329)
Liabilities from interest rate contracts	—	(30)	—	(30)
Liabilities from outstanding common stock warrants	(1)	—	—	(1)
Total liabilities	$(1)	$(337)	$(22)	$(360)

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

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a discounted cash flow model, which uses modeled forward natural gas and power prices. 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.

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, and natural gas pricing, and the difference between our plant locational prices to liquid hub prices. Power price spreads, and natural gas pricing, and the difference between our plant locational prices to liquid hub prices are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price of the spread on a buy or sell position in isolation would result in a higher/lower fair value measurement. The significant unobservable inputs used in the valuation of Dynegy's contracts classified as Level 3 as of June 30, 2017 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)	(12)	Million MWh	$ 3	Basis spread + liquid location	Basis spread	$4.25 - $6.25
FTRs	(40)	Million MWh	$ (4)	Historical congestion	Forward price	$0 - $6.00
Physical heat rate derivatives	23/(3)	Million MMBtu/Million MWh	$ (2)	Discounted Cash Flow	Forward price	$2.40 - $3.30 / $25 - $31
Natural gas derivatives (1)	103	Million MMBtu	$ 1	Illiquid location fixed price	Forward price	$2.50 - $3.10

(1) Represents forward financial and physical transactions at illiquid pricing locations and long-dated contracts.

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

	Three Months Ended June 30, 2017			
(amounts in millions)	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Total
Balance at March 31, 2017	$(17)	$ (2)	$ —	$(19)
Total gains (losses) included in earnings	7	3	(2)	8
Settlements (1)	9	—	—	9
Balance at June 30, 2017	$(1)	$ 1	$ (2)	$(2)
Unrealized gains (losses) relating to instruments held as of June 30, 2017	$7	$ 3	$ (2)	$8

	Six Months Ended June 30, 2017			
(amounts in millions)	Electricity Derivatives	Natural Gas Derivatives	Heat Rate Derivatives	Total
Balance at December 31, 2016	$8	$ (6)	$ —	$2
Acquired derivatives	1	—	—	1
Total gains (losses) included in earnings	(22)	13	(2)	(11)

Settlements (1)	12	(6)	—	6
Balance at June 30, 2017	$(1)	$ 1	$ (2)	$(2)
Unrealized gains (losses) relating to instruments held as of June 30, 2017	$(22)	$ 13	$ (2)	$(11)

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(amounts in millions)	Three Months Ended June 30, 2016			
	Electricity Derivatives	Natural Gas Derivatives	Coal Derivatives	Total
Balance at March 31, 2016	$(17)	$ (18)	$ 1	$(34)
Total gains (losses) included in earnings	(12)	—	—	(12)
Settlements (1)	5	3	—	8
Balance at June 30, 2016	$(24)	$ (15)	$ 1	$(38)
Unrealized gains (losses) relating to instruments held as of June 30, 2016	$(12)	$ —	$ —	$(12)

(amounts in millions)	Six Months Ended June 30, 2016			
	Electricity Derivatives	Natural Gas Derivatives	Coal Derivatives	Total
Balance at December 31, 2015	$(18)	$ (32)	$ 2	$(48)
Total gains (losses) included in earnings	(5)	3	—	(2)
Settlements (1)	(1)	14	(1)	12
Balance at June 30, 2016	$(24)	$ (15)	$ 1	$(38)
Unrealized gains (losses) relating to instruments held as of June 30, 2016	$(5)	$ 3	$ —	$(2)

(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 material transfers between Level 1, Level 2 and Level 3 for the three and six months ended June 30, 2017 and 2016.

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 such assets and liabilities and their placement within the fair value hierarchy.

During the three and six months ended June 30, 2017 and 2016, we recorded impairment charges related to certain of our facilities using a discounted cash flow model classified as Level 3 within the fair value hierarchy. See Note 9—Property, Plant and Equipment for further discussion. During the six months ended June 30, 2017, we fair valued the ENGIE Acquisition and our acquisition of additional joint ownership interest in the Zimmer facility. See Note 3—Acquisitions and Divestitures for further discussion of the fair value hierarchy classifications of valuations of acquired identifiable assets and liabilities and Note 10—Joint Ownership of Generating Facilities for further discussion of the acquisition of additional joint ownership interest in the Zimmer facility.

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Fair Value of Financial Instruments. The following table discloses the fair value of financial instruments which are not recognized at fair value in our unaudited consolidated balance sheets. Unless otherwise noted, the fair value of debt as reflected in the table has been calculated based on the average of certain available broker quotes as of June 30, 2017 and December 31, 2016, respectively.

		June 30, 2017		December 31, 2016	
(amounts in millions)	Fair Value Hierarchy	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Dynegy Inc.:					
Tranche C-1 Term Loan, due 2024 (1)	Level 2	$(2,129)	$(2,213)	$(1,994)	$(2,025)
Tranche B-2 Term Loan, due 2020 (1)	Level 2	$—	$—	$(219)	$(225)
Revolving Facility (1)	Level 2	$(300)	$(300)	$—	$—
6.75% Senior Notes, due 2019 (1)	Level 2	$(2,085)	$(2,163)	$(2,083)	$(2,137)
7.375% Senior Notes, due 2022 (1)	Level 2	$(1,733)	$(1,735)	$(1,731)	$(1,665)
5.875% Senior Notes, due 2023 (1)	Level 2	$(493)	$(463)	$(492)	$(431)
7.625% Senior Notes, due 2024 (1)	Level 2	$(1,236)	$(1,213)	$(1,237)	$(1,156)
8.034% Senior Notes, due 2024 (1)	Level 2	$(184)	$(175)	$—	$—
8.00% Senior Notes, due 2025 (1)	Level 2	$(738)	$(729)	$(738)	$(703)
7.00% Amortizing Notes, due 2019 (TEUs) (1)	Level 2	$(58)	$(68)	$(78)	$(90)
Forward capacity agreement (1)	Level 3	$(210)	$(210)	$(205)	$(205)
Inventory financing agreements	Level 3	$(48)	$(48)	$(129)	$(127)
Equipment financing agreements (1)	Level 3	$(103)	$(103)	$(73)	$(73)
Genco:					
Liabilities subject to compromise (2)	Level 3	$—	$—	$(825)	$(366)

(1) Carrying amounts include unamortized discounts and debt issuance costs. Please read Note 12—Debt for further discussion.

(2) Carrying amounts represent the Genco senior notes that were classified as liabilities subject to compromise as of December 31, 2016. The fair value of the senior notes was equal to the Genco Plan consideration and is a Level 3 valuation due to a lack of observable inputs that make up the consideration. Please read Note 22—Genco Chapter 11 Bankruptcy in our Form 10-K for further details.

Note 7—Cash Flow Information

The supplemental disclosures of our non-cash investing and financing information are as follows:

	Six Months Ended June 30,	
(amounts in millions)	2017	2016
Change in capital expenditures included in accounts payable	$28	$(3)
Change in capital expenditures pursuant to an equipment financing agreement	$27	$4
Issuance of 2017 Warrants	$17	$—
Issuance of senior notes related to the Genco restructuring	$185	$—
Non-cash working capital adjustment to purchase price of the ENGIE acquisition	$14	$—
Sale of interest in Conesville facility	$(57)	$—
Acquisition of interest in Zimmer facility	$27	$—

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The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within our unaudited consolidated balance sheets that sum to the total of the same such amounts shown in our unaudited consolidated statements of cash flows:

(amounts in millions)	June 30, 2017	June 30, 2016
Cash and cash equivalents	$447	$1,142
Restricted cash included in current assets (1)	—	104
Restricted cash included in long-term assets (2)	—	2,000
Total cash, cash equivalents and restricted cash	$447	$3,246

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(1) Includes $70 million placed in escrow for the issuance of the Tranche C Term Loan ($50 million of pre-funded interest and $20 million of pre-funded original issue discount) and $34 million related to collateral.
(2) Relates to amounts placed into escrow for the issuance of the Tranche C Term Loan.

Note 8—Inventory

A summary of our inventories is as follows:

(amounts in millions)	June 30, 2017	December 31, 2016
Materials and supplies	$ 254	$ 182
Coal	192	238
Fuel oil	13	17
Natural gas	15	—
Emissions allowances (1)	3	8
Total	$ 477	$ 445

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(1) At June 30, 2017 and December 31, 2016, 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)	June 30, 2017	December 31, 2016
Power generation	$10,065	$ 7,537
Buildings and improvements	1,137	944
Office and other equipment	117	98
Property, plant and equipment	11,319	8,579
Accumulated depreciation	(1,834)	(1,458)
Property, plant and equipment, net	$9,485	$ 7,121

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Impairments

For the three and six months ended June 30, 2017 and 2016, we recognized the following impairments in our unaudited consolidated statements of operations (amounts in millions):

Facility	Fair Value	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Baldwin (1)	$ 97	$—	$645	$—	$645
Killen (2)	$ —	—	—	20	—
Hennepin (1)	$ 16	10	—	10	—
Havana (1)	$ 37	89	—	89	—
Total		$99	$645	$119	$645

(1) Units failed to recover their basic operating costs in the MISO capacity auctions.

(2) In first quarter 2017, Dayton Power and Light Co., the partner and operator of Killen, announced the shutdown of the Killen generation facility by June 2018.

As a result of our impairment analysis on our coal facilities in MISO, we decreased the estimated useful lives of certain of the facilities.

Retirements

The Brayton Point facility officially retired on June 1, 2017. During the three and six months ended June 30, 2017, we recognized $5 million of severance costs, which were classified within Operating and maintenance expense in our unaudited consolidated statement of operations.

Note 10—Joint Ownership of Generating Facilities

We hold ownership interests in certain jointly owned generating facilities. We are entitled to the proportional share of the generating capacity and the output of each unit equal to our ownership interests. We pay our share of capital expenditures, fuel inventory purchases, and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to additional costs. Our share of revenues and operating costs of the jointly owned generating facilities is 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 June 30, 2017 and December 31, 2016 included in our unaudited consolidated balance sheets. Each facility is co-owned with one or more other generation companies.

(dollars in millions)	June 30, 2017 Ownership Interest	Property, Plant and Equipment	Accumulated Depreciation	Construction Work in Progress	Total
Miami Fort	64.0%	$ 209	$ (50)	$ 4	$163
Stuart (1)(2)	39.0%	$ —	$ —	$ 2	$2
Zimmer	71.9%	$ 125	$ (33)	$ 8	$100
Killen (1)(2)	33.0%	$ —	$ —	$ —	$—

(dollars in millions)	December 31, 2016 Ownership Interest	Property, Plant and	Accumulated Depreciation	Construction Work in	Total

		Equipment		Progress	
Miami Fort	64.0%	$ 207	$ (39)	$ 4	$172
Stuart (1)	39.0%	$ —	$ —	$ 4	$4
Conesville (1)	40.0%	$ 61	$ (3)	$ 6	$64
Zimmer	46.5%	$ 115	$ (25)	$ 6	$96
Killen (1)	33.0%	$ 19	$ (2)	$ 3	$20

(1) Facilities not operated by Dynegy.

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(2) Stuart Unit 1 is scheduled to be retired in the third quarter of 2017, with remaining Stuart and Killen units scheduled to be retired by mid-2018.

On May 12, 2017, the joint owners received approval to retire the units at Stuart Station and Killen effective June 1, 2018. On July 19, 2017, Stuart Unit 1 received approval from PJM to retire early effective September 30, 2017.

On May 9, 2017, Dynegy finalized the sale of its 40 percent ownership interest in Conesville to American Electric Power ("AEP") in exchange for AEP's 25.4 percent ownership interest in Zimmer. As a result, Dynegy now owns 71.9 percent of the Zimmer facility and no longer has an ownership interest in the Conesville facility. No cash was exchanged in the transaction and no additional debt was incurred by either party. AEP returned a previously issued letter of credit totaling $58 million to Dynegy. The acquisition of the additional interest in Zimmer has been accounted for as a business combination using similar fair value methodologies as described in Note 3—Acquisitions and Divestitures. The fair value of the additional Zimmer interest is $27 million and was allocated $14 million to Property, plant and equipment, $14 million to Inventory and $1 million to ARO liability in our unaudited consolidated balance sheets. As a result of the Conesville sale, we recognized a loss of $30 million for the three and six months ended June 30, 2017, representing the difference between the $57 million book value of our transferred interest in Conesville and the $27 million fair value of the acquired interest in Zimmer.

On April 21, 2017, Dynegy reached an agreement with AES Ohio Generation, LLC and The Dayton Power and Light Company (collectively, "AES") under which Dynegy will purchase AES' 28.1 percent interest in Zimmer and 36 percent interest in Miami Fort for $50 million in cash and the assumption of certain liabilities, subject to customary adjustments. The transaction is expected to close in the second half of 2017.

Note 11—Intangible Assets and Liabilities

The following table summarizes the components of our intangible assets and liabilities as of June 30, 2017 and December 31, 2016:

(amounts in millions)	June 30, 2017 Gross Carrying Amount	June 30, 2017 Accumulated Amortization	June 30, 2017 Net Carrying Amount	December 31, 2016 Gross Carrying Amount	December 31, 2016 Accumulated Amortization	December 31, 2016 Net Carrying Amount
Intangible Assets:						
Electricity contracts	$281	$ (219)	$ 62	$260	$ (206)	$ 54
Gas transport contracts	29	(10)	19	13	(6)	7
Total intangible assets	$310	$ (229)	$ 81	$273	$ (212)	$ 61
Intangible Liabilities:						
Electricity contracts	$(24)	$ 14	$ (10)	$(28)	$ 26	$ (2)
Coal contracts	(35)	33	(2)	(49)	42	(7)
Coal transport contracts	(86)	78	(8)	(86)	73	(13)
Gas transport contracts	(60)	15	(45)	(41)	8	(33)
Gas storage contracts	(2)	1	(1)	—	—	—
Total intangible liabilities	$(207)	$ 141	$ (66)	$(204)	$ 149	$ (55)
Intangible assets and liabilities, net	$103	$ (88)	$ 15	$69	$ (63)	$ 6

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The following table presents our amortization expense (revenue) of intangible assets and liabilities for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
(amounts in millions)	2017	2016	2017	2016
Electricity contracts, net (1)	$9	$17	$24	$33
Coal contracts, net (2)	(1)	(11)	(3)	(23)
Coal transport contracts, net (2)	(2)	(7)	(5)	(14)
Gas transport contracts, net (2)	(2)	—	(1)	17
Total	$4	$(1)	$15	$13

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

The following table summarizes the components of our contract based intangible assets and liabilities recorded in connection with the ENGIE Acquisition in February 2017:

(amounts in millions/months)	Gross Carrying Amount	Weighted-Average Amortization Period
Intangible Assets:		
Electricity contracts	$ 34	39
Gas transport contracts	16	47
Total intangible assets	$ 50	41
Intangible Liabilities:		
Electricity contracts	$ (11)	32
Gas contracts	—	1
Gas transport contracts	(17)	35
Gas storage contracts	(2)	13
Total intangible liabilities	$ (30)	33
Total intangible assets and liabilities, net	$ 20	

Amortization expense (revenue), net related to intangible assets and liabilities recorded in connection with the ENGIE Acquisition for the next five years as of June 30, 2017 is as follows: 2017—$(5) million, 2018—$8 million, 2019—$17 million, 2020—$4 million and 2021—$(1) million.

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Note 12—Debt

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

(amounts in millions)	June 30, 2017	December 31, 2016
Secured Obligations:		
Tranche C-1 Term Loan, due 2024 (1)	$2,218	$ 2,000
Tranche B-2 Term Loan, due 2020	—	224
Revolving Facility	300	—
Forward Capacity Agreements	230	219
Inventory Financing Agreements	48	129
Subtotal secured obligations	2,796	2,572
Unsecured Obligations:		
7.00% Amortizing Notes, due 2019 (TEUs)	60	80
6.75% Senior Notes, due 2019	2,100	2,100
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
8.034% Senior Notes, due 2024 (2)	184	—
8.00% Senior Notes, due 2025	750	750
Equipment Financing Agreements	131	97
Subtotal unsecured obligations	6,725	6,527
Total debt obligations	9,521	9,099
Unamortized debt discounts and issuance costs	(204)	(120)
	9,317	8,979
Less: Current maturities, including unamortized debt discounts and issuance costs, net	106	201
Total long-term debt	$9,211	$ 8,778

(1) At December 31, 2016, the $2.0 billion Tranche C Term Loan was held by Dynegy Finance IV. Upon the close of the ENGIE Acquisition, this debt obligation became Dynegy Inc.'s secured obligation.

(2) On the Genco Emergence Date, we issued $182 million of 8.034 percent seven-year unsecured senior notes due 2024 and on April 18, 2017, we issued an additional $3 million of such notes. See Note 18—Genco Chapter 11 Bankruptcy and Emergence for further discussion.

Credit Agreement

As of June 30, 2017, we had a $3.769 billion credit agreement, as amended, that consisted of (i) a $2.224 billion seven-year senior secured term loan facility (the "Tranche C-1 Term Loan") and (ii) $1.545 billion in senior secured revolving credit facilities (the "Revolving Facility," and collectively with the Tranche C-1 Term Loan the "Credit Agreement"). During the six months ended June 30, 2017, we made the following changes to the Credit Agreement:

- On January 10, 2017, we amended the Credit Agreement (Fourth Amendment) to increase the revolver capacity by $45 million and to extend the maturity date on $450 million in revolver capacity to 2021, which was effective upon the ENGIE Acquisition Closing Date.
- On the ENGIE Acquisition Closing Date, we amended the Credit Agreement (Fifth Amendment) to (i) reduce the interest rate applicable to the Tranche C Term Loan by 75 basis points and (ii) extend the maturity to 2024 of the existing Tranche B-2 Term Loan through the exchange of the outstanding initial Tranche B-2 Term Loan for the $2.224 billion Tranche C-1 Term Loan.

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At June 30, 2017, there was $300 million drawn on the Revolving Facility. We also had outstanding letters of credit ("LCs") of approximately $318 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. Under the Credit Agreement, if Dynegy utilizes 25 percent or more of its Revolving Facility, Dynegy must be in compliance with the Consolidated Senior Secured Net Debt to Consolidated Adjusted EBITDA ratio of 4.00:1.00. Our revolver usage at June 30, 2017 was 40 percent of the aggregate revolver commitment due to outstanding LCs and revolver draws. Based on the calculation outlined in the Credit Agreement, we were in compliance with these covenants as of June 30, 2017.

Under the terms of the Credit Agreement, existing balances under our Forward Capacity Agreement, Inventory Financing Agreements, and Equipment Financing Agreements are excluded from Net Debt, as defined in the Credit Agreement.

Senior Notes

The senior notes are unsecured and unsubordinated obligations of the Company and are guaranteed by each of the Company's current and future wholly-owned domestic subsidiaries that from time to time are a borrower or guarantor under the Credit Agreement. The senior notes indentures limit, among other things, the ability of the Company or any of the guarantors to create liens upon any principal property to secure debt for borrowed money in excess of, among other limitations, 30.0% of total assets.

Interest Rate Swaps. In March 2017, we amended our existing interest rate swaps to more closely match the terms of our Tranche C-1 Term Loan. The swaps have an aggregate notional value of approximately $765 million at an average fixed rate of 3.03 percent and expire between the second quarter of 2018 and the second quarter of 2020. In a previous extension to the existing interest rate swaps, 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 swaps are reflected as a financing activity in our unaudited consolidated statements of cash flows.

Additionally, in May 2017, we entered into new interest rate swap agreements. The swaps have an aggregate notional value of approximately $1.2 billion at an average fixed rate of 1.97 percent, and expire in the first quarter of 2024. Any cash flows related to the settlement of these swaps are reflected as an operating activity in our unaudited consolidated statements of cash flows.

Amortizing Notes

On June 21, 2016, in connection with the issuance of the tangible equity units ("TEUs"), Dynegy issued the Amortizing Notes with a principal amount of approximately $87 million. The Amortizing Notes mature on July 1, 2019. Each installment payment per Amortizing Note will be paid in cash and will constitute a partial repayment of principal and a payment of interest, computed at an annual rate of 7 percent. Interest will be calculated on the basis of a 360 day year consisting of twelve 30 day months. Payments will be applied first to the interest due and payable and then to the reduction of the unpaid principal amount, allocated as set forth in the Indenture.

The indenture limits, among other things, the ability of Dynegy to consolidate, merge, sell, or dispose all or substantially all of its assets. If a fundamental change occurs, or if Dynegy elects to settle the prepaid stock contracts ("SPCs") early, then the holders of the Amortizing Notes will have the right to require Dynegy to repurchase the Amortizing Notes at a repurchase price equal to the principal amount of the Amortizing Notes as of the repurchase date (as described in the supplemental indenture) plus accrued and unpaid interest. The Indenture also contains customary events of default which would permit the holders of the Amortizing Notes to declare those Amortizing Notes to be immediately due and payable if not cured within applicable grace periods, including the failure to make timely installment payments on the Amortizing Notes or other material indebtedness, the failure to satisfy covenants, and specified events of bankruptcy and insolvency.

Letter of Credit Facilities

Dynegy has a Letter of Credit Reimbursement Agreement with an issuing bank, for an LC in an amount not to exceed $55 million. In July 2017, the expiry date of the facility was extended one year, to September 19, 2018. At June 30, 2017, there was $55 million outstanding under this LC.

Following the ENGIE Acquisition Closing Date, Dynegy entered into a Letter of Credit Reimbursement Agreement with an issuing bank, pursuant to which the issuing bank agreed to provide LCs in an amount not to exceed $50 million. The facility matures February 7, 2018 and may be extended at the Lender's discretion for up to four additional one-year terms. As of June 30, 2017, there was $40 million outstanding under this facility.

Forward Capacity Agreement

As of June 30, 2017, we have sold a portion of our PJM capacity in Planning Years 2018-2019 and 2019-2020 to a financial institution. Dynegy will continue to be subject to the performance obligations as well as any associated performance penalties and bonus payments for those planning years. As a result, this transaction is accounted for as a debt issuance of $230 million with an implied interest rate of 4.7 percent. On March 29, 2017, we replaced an existing Planning Year 2017-2018 contract in the amount of $110 million, with a Planning Year 2019-2020 contract in the amount of $121 million. On July 7, 2017, we replaced $99 million of $109 million of an existing Planning Year 2018-2019 contract with a Planning Year 2020-2021 contract in the amount of $110 million.

Inventory Financing Agreements

Brayton Point Inventory Financing. On May 31, 2017, the Brayton Point inventory financing agreement terminated and the remaining obligation was paid. The Brayton Point facility officially retired on June 1, 2017.

Emissions Repurchase Agreements. In August 2015, we entered into two repurchase transactions with a third party in which we sold approximately $78 million of RGGI inventory and received cash. In February 2017, we repurchased approximately $30 million of the previously sold RGGI inventory. We are obligated to repurchase the remaining inventory in February 2018 at a specified price with an annualized carry cost of approximately 3.49 percent. As of June 30, 2017, there was $48 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. The related assets were recorded at the net present value of the payments of $103 million. The $28 million discount is currently being amortized as interest expense over the life of the payments.

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. On March 30, 2017, the court denied Plaintiffs' motion to certify a class action, which will be subject to an interlocutory appeal granted by the Ninth Circuit on June 13, 2017. At this time we cannot reasonably estimate a potential loss.

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Advatech Dispute. On September 2, 2016, our Genco subsidiary terminated its Second Amended and Restated Newton Flue Gas Desulfurization System Engineering, Procurement, Construction and Commissioning Services Contract dated as of December 15, 2014 with Advatech, LLC. Advatech issued Genco its final invoice on September 30, 2016 totaling $81 million. Genco contested the invoice on October 3, 2016 and believes the proper amount is less than $1 million. On October 27, 2016, Advatech initiated the dispute resolution process under the Contract and filed for arbitration on March 16, 2017. Settlement discussions required under the dispute resolution process have been unsuccessful. We believe the risk of a material loss related to this dispute to be remote. We dispute the allegations and will defend our position vigorously.

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. Dynegy is participating in the investigation. We believe the risk of a material loss related to the investigation to be remote.

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. 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. This decision may provide an additional defense to the allegations in the Newton facility NOV. In September 2016, we retired Newton Unit 2.

Zimmer NOVs. 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 State Implementation Plan, and the station's air permits involving standards applicable to opacity, sulfur dioxide, sulfuric acid mist, and heat input. The NOVs remain unresolved. We are unable to predict the outcome of these matters.

Killen and Stuart NOVs/ Notices of Intent to Sue. The EPA issued NOVs in December 2014 for Killen and Stuart, and in February 2017 for Stuart, alleging violations of opacity standards. In May and June 2017, we received two letters from the Sierra Club providing notice of its intent to sue various Dynegy entities and the owner and operator of the Killen and Stuart facilities, respectively, alleging violations of opacity standards under the CAA. We jointly own but do not operate the Killen and

Stuart facilities. The Dayton Power and Light Company, the operator of Killen and Stuart, is expected to act on behalf of itself and the co-owners with respect to these matters. We are unable to predict the outcome of these matters.

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. In August 2016, the District Court granted the plaintiffs' motion for summary judgment on certain liability issues. We filed a motion seeking interlocutory appeal of the court's summary judgment ruling. In February 2017, the appellate court denied our motion for interlocutory appeal. The District Court has scheduled the remedy phase trial for October 2018. 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 our future financial condition, results of operations, and cash flows. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses, and penalties. At this time we are unable to make a reasonable estimate of the possible costs, or range of costs, that might be incurred to resolve these matters.

Coal Combustion Residuals/ Groundwater.

MISO Segment. In 2012, the Illinois EPA ("IEPA") issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities' CCR surface impoundments. In 2016, the IEPA approved our closure and post-closure care plans for the Baldwin old east, east, and west fly ash CCR surface impoundments. We are working towards implementation of those closure plans.

At our retired Vermilion facility, which is not subject to the CCR rule, we submitted proposed corrective action plans involving closure of two CCR surface impoundments (i.e., the old east and the north impoundments) to the IEPA in 2012, with revised plans submitted in 2014. In May 2017, in response to a request from the IEPA for additional information regarding the closure of these Vermilion surface impoundments, we agreed to perform additional groundwater sampling and further analysis of closure options and riverbank stabilization options.

IPH Segment. In 2012, the IEPA issued violation notices alleging violations of groundwater standards at the Newton and Coffeen facilities' CCR surface impoundments. We are addressing these CCR surface impoundments in accordance with the CCR rule.

If remediation measures concerning groundwater are necessary at any of our coal-fired MISO or IPH Segment facilities, 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. CCR surface impoundment and landfill closure costs are reflected in our AROs.

Dam Safety Assessment Reports. 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, 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 IEPA in 2014 and await IEPA action.

In response to the Baldwin report, we notified the EPA of our action plan, which included implementation of recommended operating practices, remedial measures and studies. 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 routinely enter 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.

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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 June 30, 2017 because none were probable of occurring, nor could they be reasonably estimated.

Note 14—Income Taxes

Income Tax Benefit. 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. The income taxes related to income (loss) from continuing operations were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(amounts in millions)	2017	2016	2017	2016
Expected refund of AMT credits previously subject to a valuation allowance	$7	$ —	$7	$—
Release of valuation allowance for OCI transactions that impacted deferred income taxes	4	—	4	—
Valuation allowance release as a result of the 2017 ENGIE Acquisition and the 2016 EquiPower Acquisition	—	3	317	3
Other state taxes	5	6	1	(10)
Income tax benefit (expense)	$16	$ 9	$329	$(7)

As of June 30, 2017, 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.

Unrecognized Tax Benefits. During the first quarter of 2017, we increased our unrecognized tax benefits by $66 million as a result of the ENGIE Acquisition for uncertain tax positions included in GSENA's tax returns prior to our ownership. The entire $66 million would impact our effective tax rate if recognized.

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

In the first quarter of 2017, the Dynegy pension and other post-employment plans were amended as a result of negotiations with former Duke Midwest union participants, IBEW Local 1347. As part of these amendments, the participants' previous pension plan accrued benefits will be frozen as of December 31, 2017 and will begin accruing on January 1, 2018 with a minimum interest crediting rate of 4 percent. Other post-employment plans were amended to provide retiree medical plan benefits to only certain participants as of January 1, 2018. As a result of these amendments, we remeasured our benefit obligations and funded status of the affected plans and recorded a net-of-tax gain of approximately $15 million through accumulated other comprehensive income during the first quarter of 2017.

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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 June 30,			
(amounts in millions)	2017	2016	2017	2016
Service cost benefits earned during period	$5	$ 4	$—	$—
Interest cost on projected benefit obligation	5	5	1	1
Expected return on plan assets	(7)	(6)	(1)	(1)
Amortization of prior service credit	(1)	—	(2)	(1)
Net periodic benefit cost (gain)	$2	$ 3	$(2)	$(1)

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
(amounts in millions)	2017	2016	2017	2016
Service cost benefits earned during period	$9	$ 8	$—	$—
Interest cost on projected benefit obligation	10	10	1	2
Expected return on plan assets	(13)	(12)	(1)	(2)
Amortization of prior service credit	(1)	—	(3)	(2)
Net periodic benefit cost (gain)	$5	$ 6	$(3)	$(2)

Note 16—Stockholders' Equity
Preferred Stock
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 each of the six months ended June 30, 2017 and 2016, we paid $11 million in dividends.
On July 3, 2017, 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 period beginning on May 1, 2017 and ending on July 31, 2017. Such dividends were paid on August 1, 2017, to stockholders of record as of July 15, 2017.
Stock Purchase Agreement-Terawatt
On February 24, 2016, Dynegy entered into a Stock Purchase Agreement with Terawatt Holdings, LP (“Terawatt”), an affiliate of the ECP Funds, pursuant to which at the ENGIE Acquisition Closing Date, Dynegy issued to Terawatt 13,711,152 shares of Dynegy common stock for $150 million.
ECP Buyout
Dynegy settled its payment obligation to Energy Capital Partners (“ECP”) of $375 million on the ENGIE Acquisition Closing Date. This payment is recorded as a reduction in additional paid-in capital in our unaudited consolidated balance sheet and is reflected as a purchase of a noncontrolling interest in financing activities in our unaudited consolidated statement of cash flows as of June 30, 2017.
Earnings (Loss) Per Share
Basic earnings (loss) per share is based on the weighted average number of common shares outstanding during the period. Diluted earnings (loss) is based on the weighted average number of common shares used for the basic earnings (loss) per share computation, adjusted for the incremental issuance of shares of common stock assuming (i) our stock options and warrants are exercised under the treasury stock method, (ii) our restricted stock units and performance stock units are fully vested under the treasury stock method, and (iii) our mandatory convertible preferred stock and the SPCs are converted into common stock under the if-converted method. Please read Note 18—Capital Stock and Note 13—Tangible Equity Units in our Form 10-K for further discussion.

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The following table reflects significant components of our weighted-average shares outstanding used in the basic and diluted loss per share calculations for the three and six months ended June 30, 2017 and 2016:

(in millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Shares outstanding at the beginning of the period (1)	154	117	140	117
Weighted-average shares outstanding during the period of:				
Shares issued under long-term compensation plans	—	—	1	—
Shares issued under the PIPE Transaction	—	—	11	—
Prepaid stock purchase contract (TEUs) (1)	—	3	—	1
Basic weighted-average shares outstanding	154	120	152	118
Dilution from potentially dilutive shares (2)	—	—	19	—
Diluted weighted-average shares outstanding (3)	154	120	171	118

(1) The minimum settlement amount of the TEUs, or 23,092,460 shares, is considered to be outstanding since the issuance date of June 21, 2016, and is included in the computation of basic earnings (loss) per share for the three and six months ended June 30, 2017 and 2016. Please read Note 13—Tangible Equity Units in our Form 10-K for further discussion.

(2) Shares included in the computation of diluted earnings per share for the six months ended June 30, 2017 consist of:

- 5,425,700 additional shares upon settlement of the TEUs - which reflects the difference between the minimum settlement amount included in basic weighted-average shares outstanding and the maximum settlement amount (28,518,160 shares);
- 12,903,200 additional shares consisting of the maximum settlement amount of shares which can be converted from our outstanding mandatory convertible preferred stock; and
- 774,864 additional shares attributable to restricted stock units and performance stock units.

(3) Entities with a net loss from continuing operations are prohibited from including potential common shares in the computation of diluted per share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the three months ended June 30, 2017 and three and six months ended June 30, 2016.

For the three and six months ended June 30, 2017 and 2016, the following potentially dilutive securities were not included in the computation of diluted per share amounts because the effect would be anti-dilutive:

(in millions of shares)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Stock options	4.3	2.8	2.8	2.8
Restricted stock units	1.3	1.3	—	1.3
Performance stock units	1.6	1.2	—	1.2
Warrants	24.4	15.6	24.4	15.6
Series A 5.375% mandatory convertible preferred stock	12.9	12.9	—	12.9
Prepaid stock purchase contract (TEUs)	5.4	5.4	—	5.4
Total	49.9	39.2	27.2	39.2

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

(amounts in millions)	Six Months Ended June 30, 2017	2016
Beginning of period	$21	$19
Other comprehensive income before reclassifications:		
Actuarial gain and plan amendments (net of tax of $4 and zero, respectively)	11	—
Amounts reclassified from accumulated other comprehensive income:		
Amortization of unrecognized prior service credit (net of tax of zero and zero, respectively) (1)	(4)	(2)
Net current period other comprehensive income (loss), net of tax	7	(2)
End of period	$28	$17

(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 17—Condensed Consolidating Financial Information

Dynegy's senior notes are guaranteed by certain, but not all, of our wholly owned subsidiaries. The following condensed consolidating financial statements present the financial information of (i) Dynegy ("Parent"), which is the parent and issuer of the 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. Please read Note 12—Debt 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. The inclusion of Dynegy's subsidiaries as either guarantor subsidiaries or non-guarantor subsidiaries in the condensed consolidating financial information is determined as of the most recent balance sheet date presented. On February 2, 2017, upon Genco's emergence from bankruptcy, IPH (excluding Electric Energy, Inc.) became a guarantor to the senior notes. Accordingly, condensed consolidating financial information previously reported has been retroactively adjusted to reflect the status of Dynegy's subsidiaries as either guarantor subsidiaries or non-guarantor subsidiaries as of June 30, 2017.

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 June 30, 2017 and December 31, 2016.

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Condensed Consolidating Balance Sheet as of June 30, 2017
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$252	$ 193	$ 2	$ —	$ 447
Accounts receivable, net	145	3,111	12	(2,827)	441
Inventory	—	427	50	—	477
Other current assets	9	301	3	(88)	225
Total Current Assets	406	4,032	67	(2,915)	1,590
Property, plant and equipment, net	—	9,168	317	—	9,485
Investment in affiliates	16,393	—	4	(16,397)	—
Investment in unconsolidated affiliates	—	150	—	—	150
Goodwill	—	799	—	—	799
Assets held-for-sale	—	463	—	—	463
Other long-term assets	16	219	37	—	272
Intercompany note receivable	66	—	—	(66)	—
Total Assets	$16,881	$ 14,831	$ 425	$ (19,378)	$ 12,759
Current Liabilities					
Accounts payable	$2,459	$ 501	$ 237	$ (2,827)	$ 370
Other current liabilities	191	329	101	(88)	533
Total Current Liabilities	2,650	830	338	(2,915)	903
Debt, long-term portion, net	8,926	253	32	—	9,211
Intercompany note payable	3,042	66	—	(3,108)	—
Other long-term liabilities	140	337	49	—	526
Total Liabilities	14,758	1,486	419	(6,023)	10,640
Stockholders' Equity					
Dynegy Stockholders' Equity	2,123	16,391	6	(16,397)	2,123
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	2,123	13,349	6	(13,355)	2,123
Noncontrolling interest	—	(4)	—	—	(4)
Total Equity	2,123	13,345	6	(13,355)	2,119
Total Liabilities and Equity	$16,881	$ 14,831	$ 425	$ (19,378)	$ 12,759

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$1,529	$ 221	$ 26	$ —	$ 1,776
Restricted cash	21	41	—	—	62
Accounts receivable, net	141	2,604	39	(2,398)	386
Inventory	—	326	119	—	445
Other current assets	12	408	2	(104)	318
Total Current Assets	1,703	3,600	186	(2,502)	2,987
Property, plant and equipment, net	—	6,772	349	—	7,121
Investment in affiliates	12,175	—	—	(12,175)	—
Restricted cash	2,000	—	—	—	2,000
Goodwill	—	799	—	—	799
Other long-term assets	2	109	35	—	146
Intercompany note receivable	—	8	—	(8)	—
Total Assets	$15,880	$ 11,288	$ 570	$ (14,685)	$ 13,053
Current Liabilities					
Accounts payable	$1,990	$ 443	$ 297	$ (2,398)	$ 332
Other current liabilities	143	377	168	(104)	584
Total Current Liabilities	2,133	820	465	(2,502)	916
Liabilities subject to compromise	—	832	—	—	832
Debt, long-term portion, net	8,531	216	31	—	8,778
Intercompany note payable	3,042	—	—	(3,042)	—
Other long-term liabilities	132	313	51	(8)	488
Total Liabilities	13,838	2,181	547	(5,552)	11,014
Stockholders' Equity					
Dynegy Stockholders' Equity	2,042	12,152	23	(12,175)	2,042
Intercompany note receivable	—	(3,042)	—	3,042	—
Total Dynegy Stockholders' Equity	2,042	9,110	23	(9,133)	2,042
Noncontrolling interest	—	(3)	—	—	(3)
Total Equity	2,042	9,107	23	(9,133)	2,039
Total Liabilities and Equity	$15,880	$ 11,288	$ 570	$ (14,685)	$ 13,053

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Condensed Consolidating Statements of Operations for the Three Months Ended June 30, 2017
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 1,097	$ 97	$ (30)	$ 1,164
Cost of sales, excluding depreciation expense	—	(653)	(58)	30	(681)
Gross margin	—	444	39	—	483
Operating and maintenance expense	—	(250)	(32)	—	(282)
Depreciation expense	—	(198)	(11)	—	(209)
Impairments	—	(99)	—	—	(99)
Gain (loss) on sale of assets, net	—	(30)	1	—	(29)
General and administrative expense	(2)	(38)	(2)	—	(42)
Acquisition and integration costs	(7)	—	—	—	(7)
Other	—	1	2	—	3
Operating loss	(9)	(170)	(3)	—	(182)
Bankruptcy reorganization items	15	(16)	—	—	(1)
Earnings from unconsolidated investments	—	1	—	—	1
Equity in losses from investments in affiliates	(154)	—	—	154	—
Interest expense	(154)	(6)	(3)	4	(159)
Other income and expense, net	6	27	—	(4)	29
Loss before income taxes	(296)	(164)	(6)	154	(312)
Income tax benefit	—	16	—	—	16
Net loss attributable to Dynegy Inc.	$(296)	$ (148)	$ (6)	$ 154	$ (296)

Condensed Consolidating Statements of Operations for the Six Months Ended June 30, 2017
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 2,236	$ 258	$ (83)	$ 2,411
Cost of sales, excluding depreciation expense	—	(1,348)	(173)	83	(1,438)
Gross margin	—	888	85	—	973
Operating and maintenance expense	—	(451)	(63)	—	(514)
Depreciation expense	—	(374)	(35)	—	(409)
Impairments	—	(119)	—	—	(119)
Gain (loss) on sale of assets, net	—	(30)	1	—	(29)
General and administrative expense	(8)	(71)	(3)	—	(82)
Acquisition and integration costs	(51)	(1)	—	—	(52)
Other	—	1	—	—	1
Operating loss	(59)	(157)	(15)	—	(231)
Bankruptcy reorganization items	—	482	—	—	482
Equity in earnings from investments in affiliates	652	—	—	(652)	—
Interest expense	(315)	(12)	(6)	7	(326)
Other income and expense, net	23	30	—	(7)	46
Income (loss) before income taxes	301	343	(21)	(652)	(29)

Income tax benefit	—	329	—	—	329
Net income (loss)	301	672	(21)	(652)	300
Less: Net loss attributable to noncontrolling interest	—	(1)	—	—	(1)
Net income (loss) attributable to Dynegy Inc.	$301	$ 673	$ (21)	$ (652)	$ 301

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Condensed Consolidating Statements of Operations for the Three Months Ended June 30, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 855	$ 88	$ (39)	$ 904
Cost of sales, excluding depreciation expense	—	(489)	(43)	39	(493)
Gross margin	—	366	45	—	411
Operating and maintenance expense	—	(216)	(40)	—	(256)
Depreciation expense	—	(140)	(20)	—	(160)
Impairments	—	(645)	—	—	(645)
General and administrative expense	(1)	(37)	(1)	—	(39)
Acquisition and integration costs	—	3	—	—	3
Other	—	(8)	(8)	—	(16)
Operating loss	(1)	(677)	(24)	—	(702)
Earnings from unconsolidated investments	—	1	—	—	1
Equity in losses from investments in affiliates	(675)	—	—	675	—
Interest expense	(120)	(20)	(4)	3	(141)
Other income and expense, net	2	29	2	(3)	30
Loss before income taxes	(794)	(667)	(26)	675	(812)
Income tax benefit (expense)	(7)	16	—	—	9
Net loss	(801)	(651)	(26)	675	(803)
Less: Net loss attributable to noncontrolling interest	—	(2)	—	—	(2)
Net loss attributable to Dynegy Inc.	$(801)	$ (649)	$ (26)	$ 675	$ (801)

Condensed Consolidating Statements of Operations for the Six Months Ended June 30, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$—	$ 1,839	$ 227	$ (39)	$ 2,027
Cost of sales, excluding depreciation expense	—	(961)	(116)	39	(1,038)
Gross margin	—	878	111	—	989
Operating and maintenance expense	—	(406)	(71)	—	(477)
Depreciation expense	—	(290)	(41)	—	(331)
Impairments	—	(645)	—	—	(645)
General and administrative expense	(3)	(70)	(3)	—	(76)
Acquisition and integration costs	(3)	2	—	—	(1)
Other	—	(8)	(8)	—	(16)
Operating loss	(6)	(539)	(12)	—	(557)
Earnings from unconsolidated investments	—	3	—	—	3
Equity in losses from investments in affiliates	(557)	—	—	557	—
Interest expense	(244)	(38)	(4)	3	(283)
Other income and expense, net	3	31	—	(3)	31
Loss before income taxes	(804)	(543)	(16)	557	(806)
Income tax expense	(7)	—	—	—	(7)
Net loss	(811)	(543)	(16)	557	(813)

Less: Net loss attributable to noncontrolling interest	—	(2)	—	—	(2)
Net loss attributable to Dynegy Inc.	$(811)	$ (541)	$ (16)	$ 557	$ (811)

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Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended June 30, 2017
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	$(296)	$ (148)	$ (6)	$ 154	$ (296)
Other comprehensive income before reclassifications:					
Actuarial gain and plan amendments, net of tax of $4	(4)	—	—	—	(4)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit, net of tax of zero	(1)	—	(1)	—	(2)
Other comprehensive loss from investment in affiliates	(1)	—	—	1	—
Other comprehensive loss, net of tax	(6)	—	(1)	1	(6)
Comprehensive loss	(302)	(148)	(7)	155	(302)
Less: Comprehensive loss attributable to noncontrolling interest	—	—	—	—	—
Total comprehensive loss attributable to Dynegy Inc.	$(302)	$ (148)	$ (7)	$ 155	$ (302)

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Six Months Ended June 30, 2017
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$301	$ 672	$ (21)	$ (652)	$ 300
Other comprehensive income before reclassifications:					
Actuarial gain and plan amendments, net of tax of $4	11	—	—	—	11
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit, net of tax of zero	(3)	—	(1)	—	(4)
Other comprehensive loss from investment in affiliates	(1)	—	—	1	—
Other comprehensive income (loss), net of tax	7	—	(1)	1	7
Comprehensive income (loss)	308	672	(22)	(651)	307
Less: Comprehensive loss attributable to noncontrolling interest	—	(1)	—	—	(1)
Total comprehensive income (loss) attributable to Dynegy Inc.	$308	$ 673	$ (22)	$ (651)	$ 308

Condensed Consolidating Statements of Comprehensive Income (Loss) for the Three Months Ended June 30, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	$(801)	$ (651)	$ (26)	$ 675	$ (803)
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 loss	(802)	(651)	(26)	675	(804)

Less: Comprehensive loss attributable to noncontrolling interest	—	(2)	—	—	(2)
Total comprehensive loss attributable to Dynegy Inc.	$(802)	$ (649)	$ (26)	$ 675	$ (802)

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Condensed Consolidating Statements of Comprehensive Income (Loss) for the Six Months Ended June 30, 2016
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	$(811)	$ (543)	$ (16)	$ 557	$ (813)
Amounts reclassified from accumulated other comprehensive income:					
Amortization of unrecognized prior service credit and actuarial gain, net of tax of zero	(2)	—	—	—	(2)
Other comprehensive loss, net of tax	(2)	—	—	—	(2)
Comprehensive loss	(813)	(543)	(16)	557	(815)
Less: Comprehensive loss attributable to noncontrolling interest	—	(2)	—	—	(2)
Total comprehensive loss attributable to Dynegy Inc.	$(813)	$ (541)	$ (16)	$ 557	$ (813)

Condensed Consolidating Statements of Cash Flows for the Six Months Ended June 30, 2017
(amounts in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$(322)	$ 471	$ 81	$ —	$ 230
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(81)	(5)	—	(86)
Acquisitions, net of cash acquired	(3,259)	(4)	—	—	(3,263)
Distributions from unconsolidated investments	—	2	—	—	2
Net intercompany transfers	414	—	—	(414)	—
Other investing	—	—	1	—	1
Net cash used in investing activities	(2,845)	(83)	(4)	(414)	(3,346)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings, net of debt issuance costs	425	—	—	—	425
Repayments of borrowings	(250)	(30)	(51)	—	(331)
Proceeds from issuance of equity, net of issuance costs	150	—	—	—	150
Preferred stock dividends paid	(11)	—	—	—	(11)
Interest rate swap settlement payments	(9)	—	—	—	(9)
Acquisition of noncontrolling interest	(375)	—	—	—	(375)
Payments related to bankruptcy settlement	(120)	(3)	—	—	(123)
Net intercompany transfers	—	(364)	(50)	414	—
Intercompany borrowings, net of repayments	60	(60)	—	—	—
Other financing	(1)	—	—	—	(1)
Net cash used in financing activities	(131)	(457)	(101)	414	(275)
Net decrease in cash, cash equivalents and restricted cash	(3,298)	(69)	(24)	—	(3,391)
Cash, cash equivalents, and restricted cash beginning of period	3,550	262	26	—	3,838
Cash, cash equivalents, and restricted cash end of period	$252	$ 193	$ 2	$ —	$ 447

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Condensed Consolidating Statements of Cash Flows for the Six Months Ended June 30, 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	$(162)	$ 565	$ (28)	$ —	$ 375
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	(240)	(46)	—	(286)
Distributions from unconsolidated investments	—	8	—	—	8
Net intercompany transfers	454	—	—	(454)	—
Other investing	—	7	—	—	7
Net cash provided by (used in) investing activities	454	(225)	(46)	(454)	(271)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings, net of debt issuance costs	2,080	198	—	—	2,278
Repayments of borrowings	(4)	(15)	(1)	—	(20)
Proceeds from issuance of equity, net of issuance costs	362	—	—	—	362
Preferred stock dividends paid	(11)	—	—	—	(11)
Interest rate swap settlement payments	(9)	—	—	—	(9)
Net intercompany transfers	—	(478)	24	454	—
Other financing	(2)	—	—	—	(2)
Net cash provided by (used in) financing activities	2,416	(295)	23	454	2,598
Net increase (decrease) in cash, cash equivalents and restricted cash	2,708	45	(51)	—	2,702
Cash, cash equivalents and restricted cash, beginning of period	327	133	84	—	544
Cash, cash equivalents and restricted cash, end of period	$3,035	$ 178	$ 33	$ —	$ 3,246

Note 18—Genco Chapter 11 Bankruptcy and Emergence

On December 9, 2016, Genco filed a petition (the “Bankruptcy Petition”) under title 11 of the United States Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the Southern District of Texas (the “Bankruptcy Court”). On January 25, 2017, the Bankruptcy Court confirmed the Genco Plan and Genco emerged from bankruptcy on February 2, 2017. As a result, we eliminated $825 million of Genco senior notes and $7 million of accrued interest in exchange for:

- On the Emergence Date, $113 million of cash, $182 million of new Dynegy seven year unsecured notes, and warrants (the “2017 Warrants”) to purchase up to 8.7 million shares of common stock with a fair value of $17 million.
- On April 18, 2017, $3 million of cash, $3 million of new Dynegy seven-year unsecured notes, and 0.1 million 2017 Warrants with a fair value of less than $1 million.

The 2017 Warrants, which have an exercise price of $35 per share of common stock, have a seven-year term expiring on February 2, 2024 and are recorded as Other long-term liabilities in our unaudited consolidated balance sheet as of June 30, 2017.

The following table summarizes the Company's gain from the termination of the Genco senior notes, which is recognized in Bankruptcy reorganization items in our unaudited consolidated statement of operations for the six months ended June 30, 2017:

(amounts in millions)	
Liabilities subject to compromise, which were terminated	$832
Less:	
Seven-year unsecured notes	185
Cash consideration	116
Accrual for future potential distributions	22
2017 Warrants, at fair value	17
Legal and consulting fees	10
Bankruptcy reorganization items	$482

For income tax purposes, the income from cancellation of debt is excluded from taxable income in the current year and will instead reduce Genco's tax attributes.

As of June 30, 2017, we have accrued a liability of $22 million for remaining distributions. On August 1, 2017, approximately $6 million of cash, $4 million of new Dynegy seven-year unsecured notes, and 0.2 million 2017 Warrants with a fair value of less than $1 million were issued to remaining eligible holders of Genco senior notes and represented the final payment in the Genco restructuring. Accordingly, we will recognize an approximate $12 million additional gain to Bankruptcy reorganization items in the third quarter of 2017.

Note 19—Segment Information

We report the results of our operations in six segments: (i) PJM, (ii) NY/NE, (iii) ERCOT, (iv) MISO, (v) IPH, and (vi) CAISO. PJM also includes our Dynegy Energy Services retail business in Ohio and Pennsylvania. IPH also includes our Homefield Energy retail business in Illinois. Our unaudited consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense, and income tax benefit (expense).

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Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the three and six months ended June 30, 2017 and 2016 is presented below:
Segment Data as of and for the Three Months Ended June 30, 2017

(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Other and Eliminations	Total
Domestic:								
Unaffiliated revenues	$548	$239	$95	$86	$181	$15	$ —	$1,164
Intercompany and affiliate revenues	(14)	(2)	1	2	13	—	—	—
Total revenues	$534	$237	$96	$88	$194	$15	$ —	$1,164
Depreciation expense	$(97)	$(57)	$(21)	$(6)	$(12)	$(14)	$ (2)	$(209)
Impairments	—	—	—	(99)	—	—	—	(99)
Gain (loss) on sale of assets, net	(30)	—	—	—	1	—	—	(29)
General and administrative expense	—	—	—	—	—	—	(42)	(42)
Acquisition and integration costs	—	—	—	—	—	—	(7)	(7)
Operating income (loss)	$6	$(1)	$(30)	$(98)	$11	$(19)	$ (51)	$(182)
Bankruptcy reorganization items	—	—	—	—	(1)	—	—	(1)
Earnings from unconsolidated investments	1	—	—	—	—	—	—	1
Interest expense	—	—	—	—	—	—	(159)	(159)
Other income and expense, net	—	—	—	—	25	—	4	29
Loss before income taxes								(312)
Income tax benefit	—	—	—	—	—	—	16	16
Net loss attributable to Dynegy Inc.								$(296)
Total assets—domestic	$5,705	$3,637	$1,620	$247	$602	$478	$ 470	$12,759
Investment in unconsolidated affiliate	$72	$78	$—	$—	$—	$—	$ —	$150
Capital expenditures	$(52)	$(34)	$(8)	$(2)	$(3)	$(27)	$ (2)	$(128)

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Segment Data as of and for the Six Months Ended June 30, 2017

(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Other and Eliminations	Total
Domestic:								
Unaffiliated revenues	$1,178	$548	$112	$178	$356	$39	$ —	$2,411
Intercompany and affiliate revenues	(22)	(1)	—	10	13	—	—	—
Total revenues	$1,156	$547	$112	$188	$369	$39	$ —	$2,411
Depreciation expense	$(189)	$(119)	$(34)	$(13)	$(24)	$(26)	$ (4)	$(409)
Impairments	(20)	—	—	(99)	—	—	—	(119)
Gain (loss) on sale of assets, net	(30)	—	—	—	1	—	—	(29)
General and administrative expense	—	—	—	—	—	—	(82)	(82)
Acquisition and integration costs	—	—	—	—	—	—	(52)	(52)
Operating income (loss)	$92	$(42)	$(58)	$(81)	$29	$(33)	$ (138)	$(231)
Bankruptcy reorganization items	—	—	—	—	482	—	—	482
Interest expense	—	—	—	—	—	—	(326)	(326)
Other income and expense, net	—	—	—	—	26	—	20	46
Loss before income taxes	0	—	0	—	—	—	0	(29)
Income tax benefit	—	—	—	—	—	—	329	329
Net income								300
Less: Net loss attributable to noncontrolling interest								(1)
Net income attributable to Dynegy Inc.								$301
Total assets—domestic	$5,705	$3,637	$1,620	$247	$602	$478	$ 470	$12,759
Investment in unconsolidated affiliate	$72	$78	$—	$—	$—	$—	$ —	$150
Capital expenditures	$(68)	$(40)	$(17)	$(3)	$(6)	$(31)	$ (3)	$(168)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2017 and 2016

Segment Data as of and for the Three Months Ended June 30, 2016

(amounts in millions)	PJM	NY/NE	MISO	IPH	CAISO	Other and Eliminations	Total
Domestic:							
Unaffiliated revenues	$451	$180	$60	$166	$36	$ —	$893
Intercompany revenues	23	4	(15)	(1)	—	—	11
Total revenues	$474	$184	$45	$165	$36	$ —	$904
Depreciation expense	$(84)	$(57)	$(8)	$(5)	$(4)	$ (2)	$(160)
Impairments	—	—	(645)	—	—	—	(645)
General and administrative expense	—	—	—	—	—	(39)	(39)
Acquisition and integration costs	—	—	—	8	—	(5)	3
Operating income (loss)	$71	$(5)	$(729)	$3	$4	$ (46)	$(702)
Earnings from unconsolidated investments	1	—	—	—	—	—	1
Interest expense	—	—	—	—	—	(141)	(141)
Other income and expense, net	6	—	—	14	12	(2)	30
Loss before income taxes							(812)
Income tax benefit	—	—	—	—	—	9	9
Net loss							(803)
Less: Net loss attributable to noncontrolling interest							(2)
Net loss attributable to Dynegy Inc.							$(801)
Total assets—domestic	$5,327	$2,863	$393	$902	$516	$ 3,161	$13,162
Investment in unconsolidated affiliate	$185	$—	$—	$—	$—	$ —	$185
Capital expenditures	$(94)	$(45)	$(4)	$(11)	$(2)	$ (3)	$(159)

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended June 30, 2017 and 2016

Segment Data as of and for the Six Months Ended June 30, 2016

(amounts in millions)	PJM	NY/NE	MISO	IPH	CAISO	Other and Eliminations	Total
Domestic:							
Unaffiliated revenues	$1,008	$430	$185	$334	$59	$ —	$2,016
Intercompany revenues	28	3	(18)	(2)	—	—	11
Total revenues	$1,036	$433	$167	$332	$59	$ —	$2,027
Depreciation expense	$(169)	$(114)	$(16)	$(14)	$(15)	$ (3)	$(331)
Impairments	—	—	(645)	—	—	—	(645)
General and administrative expense	—	—	—	—	—	(76)	(76)
Acquisition and integration costs	—	—	—	8	—	(9)	(1)
Operating income (loss)	$248	$(7)	$(716)	$17	$(10)	$ (89)	$(557)
Earnings from unconsolidated investments	3	—	—	—	—	—	3
Interest expense	—	—	—	—	—	(283)	(283)
Other income and expense, net	6	—	—	14	12	(1)	31
Loss before income taxes							(806)
Income tax expense	—	—	—	—	—	(7)	(7)
Net loss							(813)
Less: Net loss attributable to noncontrolling interest							(2)
Net loss attributable to Dynegy Inc.							$(811)
Total assets—domestic	$5,327	$2,863	$393	$902	$516	$ 3,161	$13,162
Investment in unconsolidated affiliate	$185	$—	$—	$—	$—	$ —	$185
Capital expenditures	$(111)	$(74)	$(8)	$(21)	$(3)	$ (8)	$(225)

Note 20—Subsequent Events
Asset Sales
Lee. On July 10, 2017, Dynegy signed a membership interest purchase agreement (the “Lee Sale Agreement”) with an affiliate of Rockland Capital for the sale of its equity ownership interest in the Lee facility, a natural gas-fueled peaking facility in PJM, for $180 million in cash.
Dighton and Milford. On July 10, 2017, two wholly owned indirect subsidiaries of Dynegy signed a purchase and sale agreement (the “Dighton and Milford-MA Sale Agreement”) with an affiliate of Starwood Energy Group for the sale of their equity ownership interests in two intermediate natural gas-fueled facilities located in Dighton and Milford, Massachusetts, for $119 million in cash. Furthermore, the sale, when completed, will fulfill the mitigation plan approved by FERC regarding the Company’s purchase of ENGIE’s US-based asset portfolio.

DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended June 30, 2017 and 2016

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. We sell electric energy, capacity and ancillary services primarily on a wholesale basis from our power generation facilities. We also serve residential, municipal, commercial and industrial customers primarily in MISO and PJM through our Homefield Energy and Dynegy Energy Services retail businesses. We currently own approximately 28,000 MW of generating capacity in twelve states and also provide retail electricity to residential, commercial, industrial, and municipal customers in Illinois, Ohio, and Pennsylvania. We report the results of our power generation business as six separate segments in our unaudited consolidated financial statements: (i) PJM, (ii) NY/NE, (iii) ERCOT, (iv) MISO (v) IPH and (vi) CAISO.

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The charts below show our wholesale generation, retail load and Adjusted EBITDA contribution by fuel type during the six months ended June 30, 2017.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We maintain a strong focus on liquidity. We believe that we have adequate resources from a combination of our current liquidity position and cash expected to be generated from future operations and select asset sales to fund our liquidity and capital requirements as they become due. 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.

Since 2013, we have increased scale and shifted our portfolio mix, which was predominately coal-based, to a predominately gas-based portfolio, through four major acquisitions. We used a significant portion of our balance sheet capacity to finance these acquisitions. We are now focused on strengthening our balance sheet, managing debt maturities and improving our leverage profile through debt reduction primarily from operating cash flows, PRIDE initiatives and select asset sales.

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Liquidity. The following table summarizes our liquidity position at June 30, 2017 (amounts in millions):

Revolving facilities and LC capacity (1)	$1,650
Less:	
Outstanding revolver draws	(300)
Outstanding LCs	(413)
Revolving facilities and LC availability	937
Cash and cash equivalents	447
Total available liquidity	$1,384

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(1) Includes $1.545 billion in senior secured revolving credit facilities and $105 million related to LCs. Please read Note 12—Debt for further discussion.

Liquidity Highlights:

- April 2017 - We exchanged $15 million of the Genco senior notes for $3 million cash, $3 million in Dynegy senior notes, and 0.1 million 2017 Warrants.
- May 2017 - AEP returned previously issued LCs totaling $58 million to Dynegy in connection with the exchange of our interest in the Conesville facility for AEP's interest in the Zimmer facility.
- May 2017 - Brayton Point inventory financing agreement terminated and the remaining obligation was paid.
- Reduced collateral outstanding by approximately $85 million since March 31, 2017.
- July 2017 - We received approximately $479 million in proceeds from the Troy and Armstrong Sale.
- July 2017 - Refinanced previously monetized capacity under our Forward Capacity Sales Agreement by 24 months.
- July 2017 - Extended a $55 million LC for an additional year.
- August 2017 - We exchanged $25 million of the Genco senior notes for $6 million cash, $4 million in Dynegy senior notes, and 0.2 million 2017 Warrants. This was the final payment related to the Genco restructuring.

Cash Flows

The following table presents net cash from operating, investing, and financing activities for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,		
(amounts in millions)	2017	2016	Change
Net cash provided by operating activities	$230	$375	$(145)
Net cash used in investing activities	$(3,346)	$(271)	$(3,075)
Net cash provided by (used in) financing activities	$(275)	$2,598	$(2,873)

Operating Activities

Changes in net cash provided by operating activities for the six months ended June 30, 2017 compared to the same period June 30, 2016 were primarily due to:

	(in millions)
Increase in cash provided by operation of our power generation facilities and retail operations	$ 61
Increase in interest payments on our various debt agreements	(13)
Increase in payments for acquisition-related costs	(44)
Decrease in cash provided by changes in working capital and other	(149)
	$ (145)

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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 June 30, 2017 and December 31, 2016:

(amounts in millions)	June 30, 2017	December 31, 2016
Cash (1)	$ 81	$ 124
LCs	413	382
Total	$ 494	$ 506

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(1) Includes broker margin as well as other collateral postings included in Prepayments and other current assets in our unaudited consolidated balance sheets. At June 30, 2017 and December 31, 2016, $46 million and $54 million, respectively, of cash posted as collateral were netted against Liabilities from risk management activities in our unaudited consolidated balance sheets.

Collateral postings decreased from December 31, 2016 to June 30, 2017 due to reduced collateral postings in the second quarter of 2017, primarily due to an LC returned by AEP related to the Conesville/Zimmer JOU transaction, offset by increases in first quarter, primarily as the result of the ENGIE Acquisition. The fair value of our derivatives collateralized by first priority liens included liabilities of $108 million and $136 million at June 30, 2017 and December 31, 2016, respectively.

Investing Activities

Historical Investing Cash Flows. Changes in net cash used in investing activities for the six months ended June 30, 2017 compared to the same period June 30, 2016 were primarily due to:

	(in millions)
Cash paid, net of cash acquired for the ENGIE Acquisition	$ (3,263)
Decrease in capital expenditures	200
Decrease in other investing inflows	(12)
	$ (3,075)

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

	Six Months Ended June 30,		Estimated Remaining
(amounts in millions)	2017	2016	2017
PJM	$ 68	$ 111	$ 39
NY/NE	40	74	19
ERCOT	17	—	6
MISO	3	8	3
IPH	6	21	21
CAISO	31	3	4
Other	3	8	6
Total Capital Expenditures Incurred (1)	$ 168	$ 225	$ 98
Non-cash investing activities (2)	(55)	(1)	N/A
Capital work performed under prepaid long-term service agreement	(31)	—	N/A
Prepaid cash for long-term service agreements (3)	4	62	N/A

Capital Expenditures - Statement of Cash Flows	$86	$286	N/A

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(1) Includes capitalized interest of $1 million and $7 million for the six months ended June 30, 2017 and 2016, respectively.
(2) Please read Note 7—Cash Flow Information for further details.
(3) Prepaid cash reclassified into Investing Activities on the consolidated statements of cash flows.

Capital spending in our PJM, MISO, and IPH segments primarily consisted of environmental and maintenance capital projects. Capital spending in our NY/NE, ERCOT, and CAISO segments primarily consisted of only maintenance capital projects.

Future Investing Cash Flows. The expected capital expenditures for the remainder of 2017 are noted above. The capital budget is subject to revision as opportunities arise or circumstances change. The proceeds from the Troy and Armstrong Sale will be reflected as cash flows from investing activities. Please read Note 3—Acquisitions and Divestitures for further discussion.

Financing Activities

Historical Financing Cash Flows. Changes in net cash provided by financing activities for the six months ended June 30, 2017 compared to the same period June 30, 2016 were primarily due to:

	(in millions)
Decrease in proceeds from long-term borrowings, net of issuance costs, primarily related to the Tranche C-1 Term Loan, the Amortizing Notes TEUs, and draws on the Revolver	$ (1,655)
Proceeds related to the SPC TEUs in 2016	(362)
Proceeds from issuance of equity related to the PIPE Transaction in 2017	150
Proceeds related to the Forward Capacity Agreement in 2016	(198)
Cash paid related to the ECP Buyout in 2017	(375)
Cash paid related to the Genco Bankruptcy in 2017	(123)
Increase in repayment of borrowings, primarily related to the Tranche B-2 Term Loan, Inventory Financing Agreements, Equipment Financing Agreements, and TEUs	(311)
Increase in other financing activity	1
	$ (2,873)

Future Financing Cash Flows. Our future cash flows from financing activities include:

- Principal payments on our debt instruments and other financial obligations;
- Periodic payments to settle our interest rate swap agreements; and
- Dividend payments on our mandatory convertible preferred stock.

Financing Trigger Events. Our debt instruments and certain of our other financial obligations 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 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. To the extent Dynegy uses 25 percent or more of its Revolving Facility, the Fourth Amendment of the Credit Agreement requires that Dynegy must be in compliance with the Consolidated Senior Secured Net Debt to Consolidated Adjusted EBITDA ratio (as defined in the Credit Agreement). The Consolidated Senior Secured Net Debt to Consolidated Adjusted EBITDA ratio is 4.00:1.00.

We were in compliance with these covenants as of June 30, 2017.
Existing balances under our Forward Capacity Agreement, Inventory Financing Agreements, and Equipment Financing Agreements are excluded from Net Debt, as defined in the Credit Agreement.

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Senior Notes. Our senior notes indentures limit, among other things, the ability of the Company or any of the guarantors to create liens upon any principal property to secure debt for borrowed money in excess of, among other limitations, 30.0% of total assets.

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. Our dividends paid for 2017 and 2016 are as follows:

Dividend Payment Dates and Amounts Paid (amounts in millions)	2017	2016
February 1	$5.4	$5.4
May 1	$5.4	$5.4
August 1	$5.4	$5.4
November 1	$—	$5.4

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+

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 and six months ended June 30, 2017 and 2016. 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 six separate segments in our unaudited consolidated financial statements: (i) PJM, (ii) NY/NE, (iii) ERCOT, (iv) MISO, (v) IPH, and (vi) CAISO. 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 ENGIE Acquisition on February 7, 2017; therefore, the results of our newly acquired plants within our PJM, NY/NE and ERCOT segments are included in our consolidated results since the acquisition date. Please read Note 3—Acquisitions and Divestitures—ENGIE Acquisition for further discussion.

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Consolidated Summary Financial Information — Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

The following table provides summary financial data regarding our unaudited consolidated results of operations for the three months ended June 30, 2017 and 2016, respectively:

(amounts in millions)	Three Months Ended June 30, 2017	2016	Favorable (Unfavorable) $ Change
Revenues			
Energy	$917	$723	$ 194
Capacity	241	196	45
Mark-to-market loss, net	(26)	(21)	(5)
Contract amortization	(9)	(18)	9
Other	41	24	17
Total revenues	1,164	904	260
Cost of sales, excluding depreciation expense	(681)	(493)	(188)
Gross margin	483	411	72
Operating and maintenance expense	(282)	(256)	(26)
Depreciation expense	(209)	(160)	(49)
Impairments	(99)	(645)	546
Loss on sale of assets, net	(29)	—	(29)
General and administrative expense	(42)	(39)	(3)
Acquisition and integration costs	(7)	3	(10)
Other	3	(16)	19
Operating loss	(182)	(702)	520
Bankruptcy reorganization items	(1)	—	(1)
Earnings from unconsolidated investment	1	1	—
Interest expense	(159)	(141)	(18)
Other income and expense, net	29	30	(1)
Loss before income taxes	(312)	(812)	500
Income tax benefit	16	9	7
Net loss	(296)	(803)	507
Less: Net loss attributable to noncontrolling interest	—	(2)	2
Net loss attributable to Dynegy Inc.	$(296)	$(801)	$ 505

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The following tables provide summary financial data regarding our operating income (loss) by segment for the three months ended June 30, 2017 and 2016, respectively:

	Three Months Ended June 30, 2017							
(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Other	Total
Revenues	$534	$ 237	$ 96	$88	$194	$ 15	$—	$1,164
Cost of sales, excluding depreciation expense	(282)	(134)	(76)	(55)	(126)	(8)	—	(681)
Gross margin	252	103	20	33	68	7	—	483
Operating and maintenance expense	(119)	(49)	(29)	(26)	(46)	(12)	(1)	(282)
Depreciation expense	(97)	(57)	(21)	(6)	(12)	(14)	(2)	(209)
Impairments	—	—	—	(99)	—	—	—	(99)
Gain (loss) on sale of assets, net	(30)	—	—	—	1	—	—	(29)
General and administrative expense	—	—	—	—	—	—	(42)	(42)
Acquisition and integration costs	—	—	—	—	—	—	(7)	(7)
Other	—	2	—	—	—	—	1	3
Operating income (loss)	$6	$ (1)	$ (30)	$(98)	$11	$ (19)	$(51)	$(182)

	Three Months Ended June 30, 2016						
(amounts in millions)	PJM	NY/NE	MISO	IPH	CAISO	Other	Total
Revenues	$474	$ 184	$45	$165	$ 36	$—	$904
Cost of sales, excluding depreciation expense	(203)	(85)	(85)	(101)	(19)	—	(493)
Gross margin	271	99	(40)	64	17	—	411
Operating and maintenance expense	(116)	(47)	(36)	(48)	(9)	—	(256)
Depreciation expense	(84)	(57)	(8)	(5)	(4)	(2)	(160)
Impairments	—	—	(645)	—	—	—	(645)
General and administrative expense	—	—	—	—	—	(39)	(39)
Acquisition and integration costs	—	—	—	8	—	(5)	3
Other	—	—	—	(16)	—	—	(16)
Operating income (loss)	$71	$ (5)	$(729)	$3	$ 4	$(46)	$(702)

Discussion of Consolidated Results of Operations

Revenues. The following table summarizes the change in revenues by segment:

(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Total
Revenues, net of hedges, attributable to newly acquired ENGIE plants	$81	$ 69	$ 96	$ —	$—	$ —	$246
Higher (lower) realized power prices	17	25	—	(6)	(9)	8	35
Higher (lower) generation volumes (1)	(18)	(23)	—	(22)	25	(15)	(53)
Higher (lower) capacity revenues	(3)	2	—	2	13	(7)	7
Change in MTM value of derivative transactions	(45)	(27)	—	69	—	(5)	(8)
Lower contract amortization	4	—	—	—	2	2	8
Other (2)	24	7	—	—	(2)	(4)	25
Total change in revenues	$60	$ 53	$ 96	$ 43	$29	$ (21)	$260

(1) Decrease primarily due to higher outages and higher gas prices at our PJM and NY/NE segments, and unit shutdowns primarily at our MISO and IPH segments; offsetting increase primarily due to higher market prices at our IPH segment.

(2) Other primarily consists of ancillary, tolling, transmission and gas revenues.

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

(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Total
Cost of sales attributable to newly acquired ENGIE plants	$30	$ 35	$ 76	$—	$—	$—	$141
Higher (lower) prices	52	37	—	4	(6)	2	89
Higher (lower) burn volumes (1)	(19)	(25)	—	(20)	26	(12)	(50)
Lower (higher) contract amortization	11	(1)	—	—	7	—	17
Other (2)	5	3	—	(14)	(2)	(1)	(9)
Total change in cost of sales	$79	$ 49	$ 76	$(30)	$25	$(11)	$188

(1) Lower burn volumes primarily due to higher outages and higher gas prices at our PJM and NY/NE segments, and unit shutdowns at our MISO and IPH segments; offsetting increase primarily due to higher market prices at our IPH segment.
(2) Other primarily consists of transmission expenses.

Operating and Maintenance Expense. O&M expense increased by $26 million primarily due to the newly acquired ENGIE plants, partially offset by a decrease primarily due to plant shutdowns at our MISO segment.

Depreciation Expense. Depreciation expense increased by $49 million primarily due to increases from the newly acquired ENGIE plants.

Impairments. Impairments decreased by $546 million due to charges at our MISO segment on our Baldwin facility in 2016 partially offset by charges in 2017 on our Havana and Hennepin facilities. Please read Note 9—Property, Plant and Equipment for further discussion.

Loss on Sale of Assets, net. Loss on sale of assets increased by $29 million primarily due to the Conesville and Zimmer ownership interest exchange. Please read Note 10—Joint Ownership of Generating Facilities for further discussion.

General and Administrative Expense. General and administrative expense increased by $3 million primarily due to higher overhead associated with the ENGIE Acquisition.

Acquisition and Integration Costs. Acquisition and integration costs increased by $10 million primarily due to higher advisory and consulting fees.

Other. Other increased by $19 million primarily due to the termination of an above market coal supply contract in 2016 at our IPH segment.

Interest Expense. Interest expense increased by $18 million primarily due to interest on our Tranche C-1 Term Loan and 2025 Senior Notes, partially offset by a decrease due to the elimination of the Genco senior notes. Please read Note 12—Debt for further discussion.

Other Income and Expense. Other income and expense decreased by $1 million primarily due to $14 million in proceeds received in 2016 related to the 2013 AER Acquisition, a $12 million supplier settlement in 2016, and a $6 million property insurance reimbursement in 2016, partially offset by $25 million in proceeds received in 2017 related to the 2013 AER Acquisition and a $2 million change in fair value of our common stock warrants.

Income Tax Benefit (Expense). The net unfavorable change of $7 million was primarily due to recognition of AMT credits that had previously been subject to a valuation.

Net Loss Attributable to Dynegy Inc. The $505 million decrease was primarily due to (i) an $18 million income attributable to newly acquired ENGIE plants, and (ii) $546 million in lower impairment charges, partially offset by $29 million loss on sale of assets.

Discussion of Adjusted EBITDA

Non-GAAP Measures. In analyzing and planning for our business, we supplement our use of GAAP financial measures with non-GAAP financial measures, including EBITDA and Adjusted EBITDA as performance measures. 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

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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 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 warrants, (iii) the impact of impairment charges, (iv) certain amounts such as those associated with acquisitions or restructurings, (v) non-cash compensation expense, and (vi) other material or unusual items.

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 who 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).

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Adjusted EBITDA — Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2017:

	Three Months Ended June 30, 2017							
(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Other	Total
Net loss								$(296)
Income tax benefit								(16)
Other income and expense, net								(29)
Interest expense								159
Earnings from unconsolidated investments								(1)
Bankruptcy reorganization items								1
Operating income (loss)	$6	$ (1)	$ (30)	$(98)	$11	$ (19)	$(51)	$(182)
Depreciation and amortization expense	98	59	22	7	13	14	2	215
Bankruptcy reorganization items	—	—	—	—	(1)	—	—	(1)
Earnings from unconsolidated investments	1	—	—	—	—	—	—	1
Other income and expense, net	—	—	—	—	25	—	4	29
EBITDA	105	58	(8)	(91)	48	(5)	(45)	62
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude noncontrolling interest	(1)	—	—	—	(1)	—	—	(2)
Acquisition, integration and restructuring costs	—	—	—	—	—	—	6	6
Bankruptcy reorganization items	—	—	—	—	1	—	—	1
Mark-to-market adjustments, including warrants	31	2	8	(4)	—	4	(3)	38
Impairments	—	—	—	99	—	—	—	99
Loss (gain) on sale of assets, net	30	—	—	—	(1)	—	—	29
Non-cash compensation expense	—	—	—	—	—	—	5	5
Other	3	—	1	(1)	—	—	(1)	2
Adjusted EBITDA	$168	$ 60	$ 1	$3	$47	$ (1)	$(38)	$240

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2016:

	Three Months Ended June 30, 2016						
(amounts in millions)	PJM	NY/NE	MISO	IPH	CAISO	Other	Total
Net loss							$(803)
Income tax benefit							(9)
Other income and expense, net							(30)
Interest expense							141
Earnings from unconsolidated investments							(1)
Operating income (loss)	$71	$(5)	$(729)	$3	$4	$(46)	$(702)
Depreciation and amortization expense	84	60	9	3	6	2	164
Earnings from unconsolidated investments	1	—	—	—	—	—	1
Other income and expense, net	6	—	—	14	12	(2)	30
EBITDA	162	55	(720)	20	22	(46)	(507)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude noncontrolling interest	1	—	—	2	—	—	3
Acquisition, integration and restructuring costs	—	—	—	(8)	—	5	(3)
Mark-to-market adjustments, including warrants	(12)	(21)	65	(2)	(1)	—	29
Impairments	—	—	645	—	—	—	645
Non-cash compensation expense	1	—	—	—	—	4	5
Other (1)	—	—	14	(1)	—	2	15
Adjusted EBITDA	$152	$34	$4	$11	$21	$(35)	$187

(1) Other includes an adjustment to exclude Wood River's energy margin and O&M costs of $15 million for the three months ended June 30, 2016. Adjusted EBITDA did not include this adjustment for the three months ended June 30, 2017.

Adjusted EBITDA increased by $53 million. The newly acquired ENGIE plants contributed $60 million in the second quarter of 2017. The offsetting $7 million decrease was primarily driven by lower energy margin, net of hedges as a result of decreased spark spreads at the PJM gas fleet driven by higher gas costs partially offset by higher dark spreads at the PJM coal fleet and higher capacity revenue at the IPH and MISO segments. Please read Discussion of Segment Adjusted EBITDA for further information.

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Discussion of Segment Adjusted EBITDA — Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

PJM Segment

The following table provides summary financial data regarding our PJM segment results of operations for the three months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2017 (1)	Three Months Ended June 30, 2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$401	$352	$ 49
Capacity	127	105	22
Mark-to-market income (loss), net	(16)	22	(38)
Contract amortization	(4)	(11)	7
Other	26	6	20
Total operating revenues	534	474	60
Operating costs			
Cost of sales	(285)	(215)	(70)
Contract amortization	3	12	(9)
Total operating costs	(282)	(203)	(79)
Gross margin	252	271	(19)
Operating and maintenance expense	(119)	(116)	(3)
Depreciation expense	(97)	(84)	(13)
Loss on sale of assets, net	(30)	—	(30)
Operating income	6	71	(65)
Depreciation and amortization expense	98	84	14
Earnings from unconsolidated investments	1	1	—
Other income and expense, net	—	6	(6)
EBITDA	105	162	(57)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments	(1)	1	(2)
Mark-to-market adjustments	31	(12)	43
Loss on sale of assets	30	—	30
Non-cash compensation expense	—	1	(1)
Other	3	—	3
Adjusted EBITDA	$168	$152	$ 16
Million Megawatt Hours Generated	10.9	11.2	(0.3)
IMA (2):			
Combined-Cycle Facilities	87 %	98 %	
Coal-Fired Facilities	70 %	79 %	
Average Capacity Factor (3):			
Combined-Cycle Facilities	51 %	62 %	
Coal-Fired Facilities	50 %	46 %	
CDDs (4)	349	331	18
HDDs (4)	411	589	(178)
Average Market On-Peak Spark Spreads ($/MWh) (5):			
PJM West	$15.76	$21.15	$ (5.39)
AD Hub	$16.56	$27.53	$ (10.97)
Average Market On-Peak Power Prices ($/MWh) (6):			

PJM West	$33.24	$32.07	$ 1.17
AD Hub	$33.59	$30.43	$ 3.16
Average natural gas price—TetcoM3 ($/MMBtu) (7)	$2.50	$1.55	$ 0.95

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(1) Includes the activity of the assets acquired in the ENGIE Acquisition.

(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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes CTs.

(3) Reflects actual production as a percentage of available capacity. The calculation excludes CTs.

(4) Reflects CDDs or HDDs for the PJM Region based on National Oceanic and Atmospheric Association ("NOAA") data.

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

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

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

Operating income decreased by $65 million primarily due to the following:

	(in millions)
Income attributable to newly acquired plants	$ 36
Lower energy margin, net of hedges, due to the following:	
Lower spark spreads as a result of higher gas costs, partially offset by higher dark spreads	$ (20)
Lower generation volumes primarily due to higher outages	$ (8)
Lower capacity revenues as a result of lower pricing	$ (3)
Change in MTM value of derivative transactions	$ (45)
Loss on sale of assets due to the Conesville and Zimmer ownership interest exchange	$ (30)
Lower O&M costs associated with outages in 2016	$ 5

Adjusted EBITDA increased by $16 million primarily due to the following:

	(in millions)
Contribution from newly acquired plants	$ 33
Lower energy margin, net of hedges, due to the following:	
Lower spark spreads as a result of higher gas costs, partially offset by higher dark spreads as a result of higher power prices	$ (14)
Lower generation volumes primarily due to higher outages	$ (9)
Lower capacity revenues as a result of lower pricing	$ (3)
Lower O&M costs associated with outages in 2016	$ 4
Other	$ 5

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NY/NE Segment

The following table provides summary financial data regarding our NY/NE segment results of operations for the three months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2017 (1)	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$173	$107	$ 66
Capacity	59	44	15
Mark-to-market income (loss), net	(2)	21	(23)
Contract amortization	(3)	(1)	(2)
Other	10	13	(3)
Total operating revenues	237	184	53
Operating costs			
Cost of sales	(135)	(85)	(50)
Contract amortization	1	—	1
Total operating costs	(134)	(85)	(49)
Gross margin	103	99	4
Operating and maintenance expense	(49)	(47)	(2)
Depreciation expense	(57)	(57)	—
Other	2	—	2
Operating loss	(1)	(5)	4
Depreciation and amortization expense	59	60	(1)
EBITDA	58	55	3
Mark-to-market adjustments	2	(21)	23
Other	—	—	—
Adjusted EBITDA	$60	$34	$ 26
Million Megawatt Hours Generated	4.2	3.8	0.4
IMA for Combined-Cycle Facilities (2)	96 %	95 %	
Average Capacity Factor for Combined-Cycle Facilities (3)	37 %	46 %	
CDDs (4)	202	150	52
HDDs (4)	780	839	(59)
Average Market On-Peak Spark Spreads ($/MWh) (5):			
New York—Zone C	$9.63	$13.73	$ (4.10)
Mass Hub	$12.07	$11.02	$ 1.05
Average Market On-Peak Power Prices ($/MWh) (6):			
New York—Zone C	$26.67	$24.09	$ 2.58
Mass Hub	$32.19	$28.17	$ 4.02
Average natural gas price—Algonquin Citygates ($/MMBtu) (7)	$2.87	$2.44	$ 0.43

(1) Includes the activity of the assets acquired in the ENGIE Acquisition.

(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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes our Brayton Point facility.

(3) Reflects actual production as a percentage of available capacity. The calculation excludes our Brayton Point facility.

(4) Reflects CDDs or HDDs for the ISO-NE Region based on NOAA data.

(5) Reflects the average of the on-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.

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(6) Reflects the average of day-ahead settled prices for the periods presented and does not necessarily reflect prices we realized.
(7) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Operating loss decreased by $4 million primarily due to the following:

	(in millions)
Income attributable to newly acquired plants	$ 11
Lower energy margin, net of hedges, due to the following:	
Higher spark spreads	$ 2
Lower generation volumes as a result of higher outages	$ (3)
Higher capacity revenues as a result of higher pricing, partially offset by capacity lost due to the retirement of Brayton Point	$ 2
Lower O&M as a result of lower outage costs	$ 2
Change in MTM value of derivative transactions	$ (27)
Lower depreciation primarily due to the retirement of our Brayton Point facility	$ 17

Adjusted EBITDA increased by $26 million primarily due to the following:

	(in millions)
Contribution from newly acquired plants	$ 26
Lower energy margin, net of hedges, due to the following:	
Higher spark spreads	$ 4
Lower generation volumes as a result of higher outages	$ (6)
Higher capacity revenues as a result of higher pricing, partially offset by capacity lost due to the retirement of Brayton Point	$ 2
Lower O&M as a result of lower outage costs	$ 2
Other	$ (4)

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ERCOT Segment

The ERCOT segment includes the results of operations since the ENGIE Acquisition Closing Date. The following table provides summary financial data regarding our ERCOT segment for the three months ended June 30, 2017:

	Three Months Ended June 30,		Favorable (Unfavorable)
(dollars in millions, except for price information)	2017	2016	$ Change
Operating revenues			
Energy	$101	$—	N/A
Mark-to-market loss, net	(8)	—	N/A
Other	3	—	N/A
Total operating revenues	96	—	N/A
Operating costs			
Cost of sales	(75)	—	N/A
Contract amortization	(1)	—	N/A
Total operating costs	(76)	—	N/A
Gross margin	20	—	N/A
Operating and maintenance expense	(29)	—	N/A
Depreciation expense	(21)	—	N/A
Operating loss	(30)	—	N/A
Depreciation and amortization expense	22	—	N/A
EBITDA	(8)	—	N/A
Mark-to-market adjustments	8	—	N/A
Other	1	—	N/A
Adjusted EBITDA	$1	$—	N/A
Million Megawatt Hours Generated	3.2	—	N/A
IMA (1):			
Combined-Cycle Facilities	91 %	— %	
Coal-Fired Facility	100 %	— %	
Average Capacity Factor (2):			
Combined-Cycle Facilities	26 %	— %	
Coal-Fired Facility	81 %	— %	
CDDs (3)	1,070	982	88
HDDs (3)	17	30	(13)
Average Market On-Peak Spark Spreads ($/MWh) (4):			
ERCOT North	$7.71	$10.64	$ (2.93)
Average Market On-Peak Power Prices ($/MWh) (5):			
ERCOT North	$26.76	$24.29	$ 2.47
Average natural gas price—Waha Hub ($/MMBtu) (6)	$2.72	$1.95	$ 0.77

(1) 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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes CTs.

(2) Reflects actual production as a percentage of available capacity. The calculation excludes CTs.

(3) Reflects CDDs or HDDs for the ERCOT Region based on NOAA data.

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

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

Operating loss of $30 million primarily consisted of the following:

	(in millions)
Energy margin, net of realized hedges	$ 29
MTM loss	$ (8)
O&M costs	$ (29)
Depreciation and amortization expense	$ (22)

Adjusted EBITDA was $1 million primarily related to the following:

	(in millions)
Energy margin, net of realized hedges	$ 29
O&M costs	$ (29)

The Adjusted EBITDA results above are reflective of ERCOT being a primarily summer-based cooling market. Due to this, outages are generally performed between March and May in preparation for summer months. During the second quarter, the region also experienced mild temperatures and healthy wind generation resulting in lower on-peak sparks.

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MISO Segment

The following table provides summary financial data regarding our MISO segment results of operations for the three months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2017	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$75	$103	$ (28)
Capacity	9	7	2
Mark-to-market income (loss), net	4	(65)	69
Total operating revenues	88	45	43
Operating costs			
Cost of sales	(55)	(85)	30
Total operating costs	(55)	(85)	30
Gross margin	33	(40)	73
Operating and maintenance expense	(26)	(36)	10
Depreciation expense	(6)	(8)	2
Impairments	(99)	(645)	546
Operating loss	(98)	(729)	631
Depreciation and amortization expense	7	9	(2)
EBITDA	(91)	(720)	629
Mark-to-market adjustments	(4)	65	(69)
Impairments	99	645	(546)
Other (1)	(1)	14	(15)
Adjusted EBITDA	$3	$4	$ (1)
Million Megawatt Hours Generated	2.7	3.6	(0.9)
IMA for Coal-Fired Facilities (2)	84 %	86 %	
Average Capacity Factor for Coal-Fired Facilities (3)	65 %	59 %	
CDDs (4)	420	472	(52)
HDDs (4)	459	535	(76)
Average Market On-Peak Power Prices ($/MWh) (5):			
Indiana (Indy Hub)	$35.03	$31.14	$ 3.89
Commonwealth Edison (NI Hub)	$33.16	$28.87	$ 4.29

(1) Other includes an adjustment to exclude Wood River's energy margin and O&M costs of $15 million for the three months ended June 30, 2016. Adjusted EBITDA did not include this adjustment for the three months ended June 30, 2017.

(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. The 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 CDDs or HDDs for the MISO Region based on NOAA data.

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

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Operating loss decreased by $631 million primarily due to the following:

	(in millions)
Higher impairment charges primarily due to our Baldwin facility in 2016	$ 546
Higher energy margin, net of hedges due to the following:	
Lower net realized pricing	$ (5)
Lower generation volumes as a result of shutdowns in 2016	$ (6)
Change in fuel and transportation costs related to Wood River	$ 14
Change in MTM value of derivative transactions	$ 69
Higher realized capacity pricing	$ 2
Lower O&M costs due to shutdowns in 2016	$ 10

Adjusted EBITDA decreased by $1 million primarily due to the following:

	(in millions)
Lower energy margin, net of hedges due to the following:	
Lower net realized pricing	$ (6)
Lower generation volumes as a result of shutdowns in 2016	$ (3)
Higher realized capacity pricing	$ 2
Lower O&M costs due to shutdowns in 2016	$ 6

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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 June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2017	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$152	$139	$ 13
Capacity	43	30	13
Contract amortization	(2)	(4)	2
Other	1	—	1
Total operating revenues	194	165	29
Operating costs			
Cost of sales	(128)	(110)	(18)
Contract amortization	2	9	(7)
Total operating costs	(126)	(101)	(25)
Gross margin	68	64	4
Operating and maintenance expense	(46)	(48)	2
Depreciation expense	(12)	(5)	(7)
Acquisition and integration costs	—	8	(8)
Gain on sale of assets	1	—	1
Other	—	(16)	16
Operating income	11	3	8
Depreciation and amortization expense	13	3	10
Bankruptcy reorganization items	(1)	—	(1)
Other income and expense, net	25	14	11
EBITDA	48	20	28
Adjustment to exclude noncontrolling interest	(1)	2	(3)
Acquisition and integration costs	—	(8)	8
Bankruptcy reorganization items	1	—	1
Mark-to-market adjustments	—	(2)	2
Gain on sale of assets	(1)	—	(1)
Other	—	(1)	1
Adjusted EBITDA	$47	$11	$ 36
Million Megawatt Hours Generated	4.2	3.3	0.9
IMA (1)	88%	91%	
Average Capacity Factor for IPH Facilities (2)	58%	38%	
CDDs (3)	420	472	(52)
HDDs (3)	459	535	(76)
Average Market On-Peak Power Prices ($/MWh) (4):			
Indiana (Indy Hub)	$35.03	$31.14	$ 3.89
Commonwealth Edison (NI Hub)	$33.16	$28.87	$ 4.29

(1) 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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes CTs.

(2) Reflects actual production as a percentage of available capacity. The calculation excludes CTs.

(3) Reflects CDDs or HDDs for the MISO Region based on NOAA data.
(4) Reflects the average of day-ahead settled prices for the periods presented and does not necessarily reflect prices we realized.

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Operating income increased by $8 million primarily due to the following:

	(in millions)
Lower energy margin, net of hedges due to the following:	
Lower net realized power prices and lower retail contribution due to unfavorable weather	$ (8)
Higher generation as a result of higher market prices, net of 2016 shutdowns	$ 4
Higher capacity revenues due to higher pricing	$ 13

Adjusted EBITDA increased by $36 million primarily due to the following:

	(in millions)
Lower energy margin, net of hedges due to the following:	
Lower net realized power prices and lower retail contribution due to unfavorable weather	$ (8)
Higher generation as a result of higher market prices, net of 2016 shutdowns	$ 4
Higher capacity revenues due to higher pricing	$ 13
AER proceeds	$ 25

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CAISO Segment

The following table provides summary financial data regarding our CAISO segment results of operations for the three months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$15	$22	$ (7)
Capacity	3	10	(7)
Mark-to-market income (loss), net	(4)	1	(5)
Contract amortization	—	(2)	2
Other	1	5	(4)
Total operating revenues	15	36	(21)
Operating costs			
Cost of sales	(8)	(19)	11
Total operating costs	(8)	(19)	11
Gross margin	7	17	(10)
Operating and maintenance expense	(12)	(9)	(3)
Depreciation expense	(14)	(4)	(10)
Operating income (loss)	(19)	4	(23)
Depreciation and amortization expense	14	6	8
Other income and expense, net	—	12	(12)
EBITDA	(5)	22	(27)
Mark-to-market adjustments	4	(1)	5
Adjusted EBITDA	$(1)	$21	$ (22)
Million Megawatt Hours Generated	0.2	0.8	(0.6)
IMA for Combined-Cycle Facilities (1)	78%	99%	
Average Capacity Factor for Combined-Cycle Facilities (2)	11%	32%	
CDDs (3)	303	284	19
HDDs (3)	148	122	26
Average Market On-Peak Spark Spreads ($/MWh) (4):			
North of Path 15 (NP 15)	$9.50	$10.76	$ (1.26)
Average natural gas price—PG&E Citygate ($/MMBtu) (5)	$3.27	$2.17	$ 1.10

(1) 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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes CTs.

(2) Reflects actual production as a percentage of available capacity. The calculation excludes CTs.

(3) Reflects CDDs or HDDs for the CAISO Region based on NOAA data.

(4) Reflects the average of the on-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.

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Operating loss increased by $23 million primarily due to the following:

	(in millions)
Higher energy margin, net of hedges	$ 3
Lower capacity revenues due to lower contracted volumes and prices	$ (7)
Change in MTM value of derivative transactions	$ (5)
Lower tolling revenue due to expiration of tolling agreement	$ (3)
Higher O&M costs primarily due to outages	$ (3)
Higher depreciation and amortization	$ (8)

Adjusted EBITDA decreased by $22 million primarily due to the following:

	(in millions)
Higher energy margin, net of hedges	$ 3
Lower capacity revenues due to lower contracted volumes and prices	$ (7)
Lower tolling revenue due to expiration of tolling agreement	$ (3)
Higher O&M costs primarily due to outages	$ (3)
Supplier settlement in 2016	$ (12)

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Consolidated Summary Financial Information — Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The following table provides summary financial data regarding our unaudited consolidated results of operations for the six months ended June 30, 2017 and 2016, respectively:

	Six Months Ended June 30,		Favorable (Unfavorable)
(amounts in millions)	2017	2016	$ Change
Revenues			
Energy	$1,938	$1,543	$ 395
Capacity	444	380	64
Mark-to-market income (loss), net	(12)	91	(103)
Contract amortization	(24)	(35)	11
Other	65	48	17
Total revenues	2,411	2,027	384
Cost of sales, excluding depreciation expense	(1,438)	(1,038)	(400)
Gross margin	973	989	(16)
Operating and maintenance expense	(514)	(477)	(37)
Depreciation expense	(409)	(331)	(78)
Impairments	(119)	(645)	526
Loss on sale of assets, net	(29)	—	(29)
General and administrative expense	(82)	(76)	(6)
Acquisition and integration costs	(52)	(1)	(51)
Other	1	(16)	17
Operating loss	(231)	(557)	326
Bankruptcy reorganization items	482	—	482
Earnings from unconsolidated investments	—	3	(3)
Interest expense	(326)	(283)	(43)
Other income and expense, net	46	31	15
Loss before income taxes	(29)	(806)	777
Income tax benefit (expense)	329	(7)	336
Net income (loss)	300	(813)	1,113
Less: Net loss attributable to noncontrolling interest	(1)	(2)	1
Net income (loss) attributable to Dynegy Inc.	$301	$(811)	$ 1,112

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The following tables provide summary financial data regarding our operating income (loss) by segment for the six months ended June 30, 2017 and 2016, respectively:

	Six Months Ended June 30, 2017							
(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Other	Total
Revenues	$1,156	$ 547	$ 112	$188	$369	$ 39	$—	$2,411
Cost of sales, excluding depreciation expense	(619)	(373)	(93)	(105)	(229)	(19)	—	(1,438)
Gross margin	537	174	19	83	140	20	—	973
Operating and maintenance expense	(206)	(97)	(43)	(52)	(88)	(27)	(1)	(514)
Depreciation expense	(189)	(119)	(34)	(13)	(24)	(26)	(4)	(409)
Impairments	(20)	—	—	(99)	—	—	—	(119)
Gain (loss) on sale of assets, net	(30)	—	—	—	1	—	—	(29)
General and administrative expense	—	—	—	—	—	—	(82)	(82)
Acquisition and integration costs	—	—	—	—	—	—	(52)	(52)
Other	—	—	—	—	—	—	1	1
Operating income (loss)	$92	$ (42)	$ (58)	$(81)	$29	$ (33)	$(138)	$(231)

	Six Months Ended June 30, 2016						
(amounts in millions)	PJM	NY/NE	MISO	IPH	CAISO	Other	Total
Revenues	$1,036	$ 433	$167	$332	$ 59	$—	$2,027
Cost of sales, excluding depreciation expense	(416)	(239)	(148)	(200)	(35)	—	(1,038)
Gross margin	620	194	19	132	24	—	989
Operating and maintenance expense	(203)	(87)	(74)	(93)	(19)	(1)	(477)
Depreciation expense	(169)	(114)	(16)	(14)	(15)	(3)	(331)
Impairments	—	—	(645)	—	—	—	(645)
General and administrative expense	—	—	—	—	—	(76)	(76)
Acquisition and integration costs	—	—	—	8	—	(9)	(1)
Other	—	—	—	(16)	—	—	(16)
Operating income (loss)	$248	$ (7)	$(716)	$17	$ (10)	$(89)	$(557)

Discussion of Consolidated Results of Operations

Revenues. The following table summarizes the change in revenues by segment:

(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Total
Revenues, net of hedges, attributable to newly acquired ENGIE plants for the first quarter of 2017	$119	$ 92	$ 112	$ —	$—	$ —	$323
Higher (lower) realized power prices	76	92	—	(4)	(20)	12	156
Higher (lower) generation volumes (1)	(4)	(9)	—	(35)	28	(26)	(46)
Higher (lower) capacity revenues	(21)	(2)	—	3	30	(5)	5
Change in MTM value of derivative transactions	(88)	(66)	—	56	(2)	1	(99)
Lower (higher) contract amortization	4	(2)	—	—	4	3	9
Other (2)	34	9	—	1	(3)	(5)	36
Total change in revenues	$120	$ 114	$ 112	$ 21	$37	$ (20)	$384

(1) Decrease primarily due to unit shutdowns at our MISO and IPH segments and higher outages at our CAISO segment; offsetting increase primarily due to higher market prices at our IPH segment.

(2) Other primarily consists of ancillary, tolling, transmission and gas revenues.

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

(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Total
Cost of sales attributable to newly acquired ENGIE plants for the first quarter of 2017	$46	$45	$ 93	$—	$—	$—	$184
Higher (lower) prices	133	117	—	3	(7)	6	252
Higher (lower) burn volumes (1)	(6)	(12)	—	(32)	35	(22)	(37)
Lower (higher) contract amortization	21	(16)	—	—	10	—	15
Other (2)	9	—	—	(14)	(9)	—	(14)
Total change in cost of sales	$203	$134	$ 93	$(43)	$29	$(16)	$400

(1) Lower burn volumes primarily due to higher gas prices at our PJM and NY/NE segments, unit shutdowns at our MISO and IPH segments, and higher outages at our CAISO segment; offsetting increase primarily due to higher market prices at our IPH segment.
(2) Other primarily consists of transmission expenses.

Operating and Maintenance Expense. O&M expense increased by $37 million primarily due to the newly acquired ENGIE plants, partially offset by a decrease primarily due to plant shutdowns at our MISO segment.

Depreciation Expense. Depreciation expense increased by $78 million primarily due to increases from the newly acquired ENGIE plants.

Impairments. Impairments decreased by $526 million primarily due to charges in 2016 at our MISO segment on our Baldwin facility, partially offset by charges in 2017 on our Havana and Hennepin facilities at our MISO segment and on our Killen facility at our PJM segment. Please read Note 9—Property, Plant and Equipment for further discussion.

Loss on Sale of Assets, net. Loss on sale of assets, net increased by $29 million primarily due to the Conesville and Zimmer ownership interest exchange. Please read Note 10—Joint Ownership of Generating Facilities for further discussion.

General and Administrative Expense. General and administrative expense increased by $6 million primarily due to higher overhead associated with the ENGIE Acquisition and higher legal fees.

Acquisition and Integration Costs. Acquisition and integration costs increased by $51 million due to $41 million higher advisory and consulting fees, and $10 million higher severance, retention, and payroll costs primarily related to the ENGIE Acquisition in 2017.

Other. Other decreased by $17 million primarily due to the termination of an above market coal supply contract in 2016 at our IPH segment.

Bankruptcy Reorganization Items. Bankruptcy reorganization items increased by $482 million primarily due to the gain on extinguishment of debt and legal costs associated with the Genco bankruptcy reorganization. Please read Note 18—Genco Chapter 11 Bankruptcy and Emergence—Reorganization items for further discussion.

Interest Expense. Interest expense increased by $43 million primarily due to interest on our Tranche C-1 Term Loan and 2025 Senior Notes, partially offset by a decrease due to the elimination of the Genco senior notes. Please read Note 12—Debt for further discussion.

Other Income and Expense. Other income and expense increased by $15 million primarily due to $25 million in proceeds received in 2017 related to the 2013 AER Acquisition, $3 million interest income on the Tranche C Term Loan that was held in escrow, and a $13 million change in fair value of our common stock warrants, partially offset by $14 million in proceeds received in 2016 related to the 2013 AER Acquisition, a $12 million supplier settlement in 2016, and a $6 million property insurance reimbursement in 2016.

Income Tax Benefit (Expense). The net favorable change of $336 million was primarily due to a partial release of our deferred tax asset valuation allowance as a result of the ENGIE Acquisition and recognition of AMT credits that had been previously subject to a valuation.

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Net Income (Loss) Attributable to Dynegy Inc. The $1.112 billion increase was primarily due to (i) a $4 million loss attributable to newly acquired ENGIE plants, (ii) income from a $317 million deferred tax valuation allowance release in 2017, (iii) a $482 million gain primarily due to extinguishment of debt associated with the Genco bankruptcy reorganization, and (iv) $526 million lower impairment charges, partially offset by (i) $99 million in non-cash mark-to-market losses associated with our hedging transactions, (ii) $52 million in acquisition and integration costs related to the ENGIE Acquisition, and (iii) $29 million loss on sale of assets.

Adjusted EBITDA — Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2017:

	Six Months Ended June 30, 2017							
(amounts in millions)	PJM	NY/NE	ERCOT	MISO	IPH	CAISO	Other	Total
Net income								$300
Income tax benefit								(329)
Other income and expense, net								(46)
Interest expense								326
Bankruptcy reorganization items								(482)
Operating income (loss)	$92	$(42)	$(58)	$(81)	$29	$(33)	$(138)	$(231)
Depreciation and amortization expense	198	127	35	15	27	29	4	435
Bankruptcy reorganization items	—	—	—	—	482	—	—	482
Other income and expense, net	—	—	—	—	26	—	20	46
EBITDA	290	85	(23)	(66)	564	(4)	(114)	732
Adjustments to reflect Adjusted EBITDA to exclude noncontrolling interest	—	—	—	—	(1)	—	—	(1)
Acquisition, integration and restructuring costs	—	—	—	—	—	—	52	52
Bankruptcy reorganization items	—	—	—	—	(482)	—	—	(482)
Mark-to-market adjustments, including warrants	16	17	14	(19)	(1)	—	(15)	12
Impairments	20	—	—	99	—	—	—	119
Loss (gain) on sale of assets, net	30	—	—	—	(1)	—	—	29
Non-cash compensation expense	—	—	—	—	—	—	10	10
Other	3	—	1	(1)	(1)	—	(3)	(1)
Adjusted EBITDA	$359	$102	$(8)	$13	$78	$(4)	$(70)	$470

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The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2016:

	Six Months Ended June 30, 2016						
(amounts in millions)	PJM	NY/NE	MISO	IPH	CAISO	Other	Total
Net loss attributable to Dynegy Inc.							$(813)
Income tax expense							7
Other income and expense, net							(31)
Interest expense							283
Earnings from unconsolidated investments							(3)
Operating income (loss)	$248	$ (7)	$(716)	$17	$ (10)	$(89)	$(557)
Depreciation and amortization expense	167	135	18	13	18	3	354
Earnings from unconsolidated investments	3	—	—	—	—	—	3
Other income and expense, net	6	—	—	14	12	(1)	31
EBITDA	424	128	(698)	44	20	(87)	(169)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude noncontrolling interest	4	—	—	2	—	—	6
Acquisition and integration costs	—	—	—	(8)	—	9	1
Mark-to-market adjustments, including warrants	(68)	(41)	37	(5)	1	(1)	(77)
Impairments	—	—	645	—	—	—	645
Non-cash compensation expense	1	—	—	—	—	11	12
Other (1)	—	—	19	(1)	—	2	20
Adjusted EBITDA	$361	$ 87	$3	$32	$ 21	$(66)	$438

(1) Other includes an adjustment to exclude Wood River's energy margin and O&M costs of $20 million for the six months ended June 30, 2016. Adjusted EBITDA did not include this adjustment for the six months ended June 30, 2017.

Adjusted EBITDA increased by $32 million. The newly acquired ENGIE plants contributed $75 million in 2017. The offsetting $43 million decrease was primarily driven by lower energy margin, net of hedges as a result of decreased spark spreads at the PJM segment and decreased dark spreads at the NY/NE segment, both driven by mild winter weather. Please read Discussion of Segment Adjusted EBITDA for further information.

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Discussion of Segment Adjusted EBITDA — Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

PJM Segment

The following table provides summary financial data regarding our PJM segment results of operations for the six months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2017 (1)	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$899	$747	$ 152
Capacity	234	216	18
Mark-to-market income (loss), net	(1)	78	(79)
Contract amortization	(13)	(21)	8
Other	37	16	21
Total operating revenues	1,156	1,036	120
Operating costs			
Cost of sales	(625)	(441)	(184)
Contract amortization	6	25	(19)
Total operating costs	(619)	(416)	(203)
Gross margin	537	620	(83)
Operating and maintenance expense	(206)	(203)	(3)
Depreciation expense	(189)	(169)	(20)
Impairments	(20)	—	(20)
Loss on sale of assets	(30)	—	(30)
Operating income	92	248	(156)
Depreciation and amortization expense	198	167	31
Earnings from unconsolidated investments	—	3	(3)
Other income and expense, net	—	6	(6)
EBITDA	290	424	(134)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments	—	4	(4)
Mark-to-market adjustments	16	(68)	84
Impairments	20	—	20
Loss on sale of assets	30	—	30
Non-cash compensation expense	—	1	(1)
Other	3	—	3
Adjusted EBITDA	$359	$361	$ (2)
Million Megawatt Hours Generated	24.3	24.2	0.1
IMA (2):			
Combined-Cycle Facilities	88 %	98 %	
Coal-Fired Facilities	68 %	78 %	
Average Capacity Factor (3):			
Combined-Cycle Facilities	59 %	72 %	
Coal-Fired Facilities	55 %	44 %	
CDDs (4)	350	334	16
HDDs (4)	2,636	3,038	(402)
Average Market On-Peak Spark Spreads ($/MWh) (5):			
PJM West	$13.57	$19.94	$ (6.37)

AD Hub	$14.59	$29.68	$ (15.09)
Average Market On-Peak Power Prices ($/MWh) (6):			
PJM West	$32.88	$31.78	$ 1.10
AD Hub	$32.49	$29.61	$ 2.88
Average natural gas price—TetcoM3 ($/MMBtu) (7)	$2.76	$1.69	$ 1.07

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(1) Includes the activity of the assets acquired in the ENGIE Acquisition for our period of ownership. Million Megawatt Hours Generated and Average Capacity Factor include such activity for the full month of February. IMA excludes such activity for our period of ownership in February.

(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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes CTs.

(3) Reflects actual production as a percentage of available capacity. The calculation excludes CTs.

(4) Reflects CDDs or HDDs for the PJM Region based on NOAA data.

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

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

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

Operating income decreased by $156 million primarily due to the following:

	(in millions)
Income attributable to newly acquired plants	$ 49
Lower energy margin, net of hedges, primarily due to the following:	
Lower spark spreads as a result of mild winter weather and higher gas costs	$ (36)
Lower generation volumes primarily due to higher outages	$ (5)
Lower capacity revenues as a result of lower pricing	$ (21)
Change in MTM value of derivative transactions	$ (88)
Asset impairments	$ (20)
Loss on sale of assets due to the Conesville and Zimmer ownership interest exchange	$ (30)
Lower O&M costs associated with outages in 2016	$ 9

Adjusted EBITDA decreased by $2 million primarily due to the following:

	(in millions)
Contribution from newly acquired plants	$ 49
Lower energy margin, net of hedges, primarily due to the following:	
Lower spark spreads as a result of mild winter weather and higher gas costs	$ (30)
Lower generation volumes primarily due to higher outages	$ (10)
Lower capacity revenues as a result of lower pricing	$ (21)
Lower O&M costs associated with outages in 2016	$ 8

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NY/NE Segment

The following table provides summary financial data regarding our NY/NE segment results of operations for the six months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2017 (1)	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$446	$278	$ 168
Capacity	105	87	18
Mark-to-market income (loss), net	(17)	48	(65)
Contract amortization	(7)	(3)	(4)
Other	20	23	(3)
Total operating revenues	547	433	114
Operating costs			
Cost of sales	(373)	(223)	(150)
Contract amortization	—	(16)	16
Total operating costs	(373)	(239)	(134)
Gross margin	174	194	(20)
Operating and maintenance expense	(97)	(87)	(10)
Depreciation expense	(119)	(114)	(5)
Operating loss	(42)	(7)	(35)
Depreciation and amortization expense	127	135	(8)
EBITDA	85	128	(43)
Mark-to-market adjustments	17	(41)	58
Adjusted EBITDA	$102	$87	$ 15
Million Megawatt Hours Generated	8.9	7.7	1.2
IMA for Combined-Cycle Facilities (2)	97%	92%	
Average Capacity Factor for Combined-Cycle Facilities (3)	37%	43%	
CDDs (4)	202	150	52
HDDs (4)	3,552	3,558	(6)
Average Market On-Peak Spark Spreads ($/MWh) (5):			
New York—Zone C	$10.69	$13.04	$ (2.35)
Mass Hub	$9.35	$10.92	$ (1.57)
Average Market On-Peak Power Prices ($/MWh) (6):			
New York—Zone C	$28.59	$22.71	$ 5.88
Mass Hub	$34.98	$31.01	$ 3.97
Average natural gas price—Algonquin Citygates ($/MMBtu) (7)	$3.66	$2.87	$ 0.79

(1) Adjusted EBITDA includes the activity of the assets acquired in the ENGIE Acquisition for our period of ownership. Million Megawatt Hours Generated and Average Capacity Factor include such activity for the full month of February. IMA excludes such activity for our period of ownership in February.

(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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes our Brayton Point facility.

(3) Reflects actual production as a percentage of available capacity. The calculation excludes our Brayton Point facility.

(4) Reflects CDDs or HDDs for the ISO-NE Region based on NOAA data.

(5) Reflects the average of the on-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.

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(6) Reflects the average of day-ahead settled prices for the periods presented and does not necessarily reflect prices we realized.
(7) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Operating loss increased by $35 million primarily due to the following:

	(in millions)
Income attributable to newly acquired plants in 2017	$ 6
Lower energy margin, net of hedges, primarily due to the following:	
Lower dark spreads as a result of mild winter weather partially offset by higher spark spreads	$ (6)
Lower generation volumes as a result of higher outages	$ (5)
Lower capacity revenues as a result of lower pricing and capacity lost due to the retirement of Brayton Point	$ (2)
Change in MTM value of derivative transactions	$ (66)
Lower contract amortization	$ 14
Lower depreciation primarily due to the retirement of our Brayton Point facility	$ 22

Adjusted EBITDA increased by $15 million primarily due to the following:

	(in millions)
Contribution from newly acquired plants in 2017	$ 34
Lower energy margin, net of hedges, primarily due to the following:	
Lower dark spreads as a result of mild winter weather partially offset by higher spark spreads	$ (14)
Lower generation volumes as a result of higher outages	$ (4)
Lower capacity revenues as a result of lower pricing and capacity lost due to the retirement of our Brayton Point facility	$ (2)

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ERCOT Segment

The ERCOT segment includes the results of operations since the ENGIE Acquisition Closing Date. The following table provides summary financial data regarding our ERCOT segment for the six months ended June 30, 2017:

(dollars in millions, except for price information)	Six Months Ended June 30, 2017	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$123	$—	N/A
Mark-to-market loss, net	(14)	—	N/A
Other	3	—	N/A
Total operating revenues	112	—	N/A
Operating costs			
Cost of sales	(92)	—	N/A
Contract amortization	(1)	—	N/A
Total operating costs	(93)	—	N/A
Gross margin	19	—	N/A
Operating and maintenance expense	(43)	—	N/A
Depreciation expense	(34)	—	N/A
Operating loss	(58)	—	N/A
Depreciation and amortization expense	35	—	N/A
EBITDA	(23)	—	N/A
Mark-to-market adjustments	14	—	N/A
Other	1	—	N/A
Adjusted EBITDA	$(8)	$—	N/A
Million Megawatt Hours Generated (1)	3.8	—	N/A
IMA (1)(2):			
Combined-Cycle Facilities	93 %	— %	
Coal-Fired Facility	98 %	— %	
Average Capacity Factor (1)(3):			
Combined-Cycle Facilities	20 %	— %	
Coal-Fired Facility	56 %	— %	
CDDs (4)	1,337	1,102	235
HDDs (4)	511	788	(277)
Average Market On-Peak Spark Spreads ($/MWh) (5):			
ERCOT North	$5.91	$8.64	$ (2.73)
Average Market On-Peak Power Prices ($/MWh) (6):			
ERCOT North	$25.15	$21.95	$ 3.20
Average natural gas price—Waha Hub ($/MMBtu) (7)	$2.75	$1.90	$ 0.85

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(1) Million Megawatt Hours Generated and Average Capacity Factor include such activity for the full month of February. IMA excludes such activity for our period of ownership in February.

(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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes CTs.

(3) Reflects actual production as a percentage of available capacity. The calculation excludes CTs.

(4) Reflects CDDs or HDDs for the ERCOT Region based on NOAA data.

(5)

Reflects the average of the on-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.

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

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

Operating loss of $58 million primarily consisted of the following:

	(in millions)
Energy margin, net of realized hedges	$ 34
MTM loss	$ (14)
O&M costs	$ (43)
Depreciation and amortization expense	$ (35)

Adjusted EBITDA was a loss of $8 million primarily related to the following:

	(in millions)
Energy margin, net of realized hedges	$ 34
O&M costs	$ (43)

The results above are reflective of ERCOT being a primarily summer-based cooling market. Due to this, outages are generally performed between March and May in preparation for summer months. Over the first half of the year, the region also experienced mild temperatures and healthy wind generation resulting in lower on-peak sparks.

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MISO Segment

The following table provides summary financial data regarding our MISO segment results of operations for the six months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2017	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$152	$191	$ (39)
Capacity	16	13	3
Mark-to-market income (loss), net	19	(37)	56
Other	1	—	1
Total operating revenues	188	167	21
Operating costs			
Cost of sales	(105)	(148)	43
Total operating costs	(105)	(148)	43
Gross margin	83	19	64
Operating and maintenance expense	(52)	(74)	22
Depreciation expense	(13)	(16)	3
Impairments	(99)	(645)	546
Operating loss	(81)	(716)	635
Depreciation and amortization expense	15	18	(3)
EBITDA	(66)	(698)	632
Mark-to-market adjustments	(19)	37	(56)
Impairments	99	645	(546)
Other (1)	(1)	19	(20)
Adjusted EBITDA	$13	$3	$ 10
Million Megawatt Hours Generated	5.4	7.0	(1.6)
IMA for Coal-Fired Facilities (2)	87 %	87 %	
Average Capacity Factor for Coal-Fired Facilities (3)	65 %	54 %	
CDDs (4)	476	500	(24)
HDDs (4)	2,662	2,959	(297)
Average Market On-Peak Power Prices ($/MWh) (5):			
Indiana (Indy Hub)	$33.84	$28.38	$ 5.46
Commonwealth Edison (NI Hub)	$31.71	$28.11	$ 3.60

(1) Other includes an adjustment to exclude Wood River’s energy margin and O&M costs of $20 million for the six months ended June 30, 2016. Adjusted EBITDA did not include this adjustment for the six months ended June 30, 2017.

(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. The 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 CDDs or HDDs for the MISO Region based on NOAA data.

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

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Operating loss decreased by $635 million primarily due to the following:

	(in millions)
Higher impairment charges primarily due to our Baldwin facility in 2016	$ 546
Higher energy margin, net of hedges due to the following:	
Lower generation volumes as a result of shutdowns in 2016	$ (10)
Change in fuel and transportation costs related to Wood River	$ 14
Higher realized capacity pricing	$ 3
Change in MTM value of derivative transactions	$ 56
Lower O&M costs primarily due to shutdowns in 2016	$ 22

Adjusted EBITDA increased by $10 million primarily due to the following:

	(in millions)
Lower energy margin, net of hedges due to the following:	
Lower net realized pricing due to milder weather	$ (3)
Lower generation volumes as a result of shutdowns in 2016	$ (4)
Higher realized capacity pricing	$ 3
Lower O&M costs due to shutdowns in 2016	$ 13

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IPH Segment

The following table provides summary financial data regarding our IPH segment results of operations for the six months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2017	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$289	$284	$ 5
Capacity	82	52	30
Mark-to-market income, net	1	3	(2)
Contract amortization	(4)	(8)	4
Other	1	1	—
Total operating revenues	369	332	37
Operating costs			
Cost of sales	(233)	(214)	(19)
Contract amortization	4	14	(10)
Total operating costs	(229)	(200)	(29)
Gross margin	140	132	8
Operating and maintenance expense	(88)	(93)	5
Depreciation expense	(24)	(14)	(10)
Acquisition and integration costs	—	8	(8)
Other	1	(16)	17
Operating income	29	17	12
Depreciation and amortization expense	27	13	14
Bankruptcy reorganization items	482	—	482
Other income and expense, net	26	14	12
EBITDA	564	44	520
Adjustment to exclude noncontrolling interest	(1)	2	(3)
Acquisition and integration costs	—	(8)	8
Bankruptcy reorganization items	(482)	—	(482)
Mark-to-market adjustments	(1)	(5)	4
Gain on sale of assets, net	(1)	—	(1)
Other	(1)	(1)	—
Adjusted EBITDA	$78	$32	$ 46
Million Megawatt Hours Generated	8.0	6.6	1.4
IMA (1)	87 %	89 %	
Average Capacity Factor for IPH Facilities (2)	55 %	38 %	
CDDs (3)	476	500	(24)
HDDs (3)	2,662	2,959	(297)
Average Market On-Peak Power Prices ($/MWh) (4):			
Indiana (Indy Hub)	$33.84	$28.38	$ 5.46
Commonwealth Edison (NI Hub)	$31.71	$28.11	$ 3.60

(1) 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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes CTs.

(2) Reflects actual production as a percentage of available capacity. The calculation excludes CTs.

(3) Reflects CDDs or HDDs for the MISO Region based on NOAA data.

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

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Operating income increased by $12 million primarily due to the following:

	(in millions)
Lower energy margin, net of hedges due to the following:	
Lower net realized power prices and lower retail contribution due to unfavorable weather	$ (21)
Higher generation as a result of higher market prices	$ 9
Higher capacity revenues due to higher price and volume	$ 30
Lower O&M costs due to shutdowns in 2016	$ 5
Change in MTM value of derivative transactions	$ (2)
Higher depreciation expense	$ (10)

Adjusted EBITDA increased by $46 million primarily due to the following:

	(in millions)
Lower energy margin, net of hedges due to the following:	
Lower net realized power prices and lower retail contribution due to unfavorable weather	$ (21)
Higher generation as a result of higher market prices	$ 9
Higher capacity revenues due to higher price and volume	$ 30
Lower O&M costs due to shutdowns in 2016	$ 4
AER proceeds	$ 25

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CAISO Segment

The following table provides summary financial data regarding our CAISO segment results of operations for the six months ended June 30, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Six Months Ended June 30, 2017	2016	Favorable (Unfavorable) $ Change
Operating revenues			
Energy	$29	$43	$ (14)
Capacity	7	12	(5)
Mark-to-market loss, net	—	(1)	1
Contract amortization	—	(3)	3
Other	3	8	(5)
Total operating revenues	39	59	(20)
Operating costs			
Cost of sales	(19)	(35)	16
Total operating costs	(19)	(35)	16
Gross margin	20	24	(4)
Operating and maintenance expense	(27)	(19)	(8)
Depreciation expense	(26)	(15)	(11)
Operating loss	(33)	(10)	(23)
Depreciation and amortization expense	29	18	11
Other income and expense, net	—	12	(12)
EBITDA	(4)	20	(24)
Mark-to-market adjustments	—	1	(1)
Other	—	—	—
Adjusted EBITDA	$(4)	$21	$ (25)
Million Megawatt Hours Generated	0.5	1.4	(0.9)
IMA for Combined-Cycle Facilities (1)	85 %	99 %	
Average Capacity Factor for Combined-Cycle Facilities (2)	12 %	31 %	
CDDs (3)	328	328	—
HDDs (3)	866	715	151
Average Market On-Peak Spark Spreads ($/MWh) (4):			
North of Path 15 (NP 15)	$8.92	$10.74	$ (1.82)
Average natural gas price—PG&E Citygate ($/MMBtu) (5)	$3.31	$2.18	$ 1.13

(1) 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. The calculation excludes certain events outside of management control such as weather related issues. The calculation excludes CTs.
(2) Reflects actual production as a percentage of available capacity. The calculation excludes CTs.
(3) Reflects CDDs or HDDs for the CAISO Region based on NOAA data.
(4) Reflects the average of the on-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.

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Operating loss increased by $23 million primarily due to the following:

	(in millions)
Higher energy margin, net of hedges	$ 2
Lower capacity revenues due to lower contracted volumes and prices	$ (5)
Lower tolling revenue due to expiration of tolling agreement	$ (5)
Higher O&M costs primarily due to outages and ARO accretion	$ (8)
Higher depreciation and amortization	$ (8)

Adjusted EBITDA decreased by $25 million primarily due to the following:

	(in millions)
Higher energy margin, net of hedges	$ 2
Lower capacity revenues due to lower contracted volumes and prices	$ (5)
Lower tolling revenue due to expiration of tolling agreement	$ (5)
Higher O&M costs primarily due to outages	$ (4)
Supplier settlement in 2016	$ (12)

Outlook

We expect that our future financial results will continue to be impacted by market structure and prices for electric energy, capacity, and ancillary services, including pricing at our plant locations relative to pricing at their respective trading hubs, the volatility of fuel and electricity prices, transportation and transmission logistics, weather conditions, and the availability of our plants. Further, there is a trend toward greater environmental regulation of all aspects of our business. As this trend continues, it is possible that we will experience additional costs related to water, air, and coal ash regulations.

Certain states (Illinois, New York and Ohio) in our markets have passed legislation or orders whereby those states will subsidize certain nuclear energy producers. These subsidies have and will continue to adversely affect the energy and capacity markets by artificially suppressing prices. As a result, we are currently a party to lawsuits in Illinois and New York challenging these subsidy programs. Other states including Connecticut, New Jersey and Pennsylvania are also considering similar nuclear subsidy programs. Please read Environmental and Regulatory Matters below for further discussion.

The portions of our generation volumes sold, coal requirements contracted, coal requirements priced, and coal transportation requirements contracted, by segment, are discussed below. We look to procure and price additional coal and coal transportation opportunistically. For our gas-fired fleet, we hedge price risk by selling forward spark spreads which involves purchasing the required amount of natural gas at the same time as we sell power. We expect to continue our hedging program for energy over a one- to three-year period using various instruments, including retail sales in our PJM and IPH segments, and in accordance with our risk management policy.

Since 2013, we have increased scale and shifted our portfolio mix, which was predominately coal-based, to a predominately gas-based portfolio, through four major acquisitions. We used a significant portion of our balance sheet capacity to finance these acquisitions. We are now focused on strengthening our balance sheet, managing debt maturities and improving our leverage profile through debt reduction primarily from operating cash flows, PRIDE initiatives and select asset sales.

Our Operating Segments

PJM Segment. The PJM segment is comprised of 20 power generation facilities located within the PJM region, with a total generating capacity of 12,020 MW. We have recently announced the planned retirements of our jointly owned Stuart and Killen facilities by mid-2018, with Stuart Unit 1 retiring early on September 30, 2017. On July 11, 2017, we completed the Troy and Armstrong Sale. On July 10, 2017, we completed the Lee Sale Agreement (787 MW).

In PJM, we are installing a total of 308 MW of uprates, which will be accomplished primarily through upgrades to the hot gas path components of our combined-cycle gas turbines and one peaking facility. The uprates are expected to be completed in the spring of 2018.

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PJM introduced its new Capacity Performance (“CP”) product beginning with the Planning Year 2016-2017 capacity auction. CP resources must be capable of sustainable, predictable operation that allows them to be available to provide energy and reserves during performance assessment hours throughout the Delivery Year. Beginning in Planning Year 2018-2019, PJM introduced the Base product, which, alongside CP, replaced the legacy capacity product. Base capacity resources are those capacity resources that are not capable of sustained, predictable operation throughout the entire delivery year, but are capable of providing energy and reserves during hot weather operations. They are subject to non-performance charges assessed during emergency conditions, from June through September.

We use our retail business to hedge a portion of the energy output from our facilities. Our portfolio beyond 2018 is primarily open to benefit from possible future power market pricing improvements.

The following table reflects our hedging activities as of June 30, 2017:

	2017	2018	2019 to 2021
Generation volumes hedged	84%	61%	10%
Coal requirements contracted (1)	95%	93%	24%
Coal requirements priced (1)	95%	93%	13%
Coal transportation requirements contracted (1)	100%	100%	100%

(1) Excludes non-operated jointly-owned generating units.

PJM Capacity Market. The most recent Reliability Pricing Model auction results, for the zones in which our assets are located, are as follows for each Planning Year:

	2017-2018		2018-2019		2019-2020		2020-2021
(price per MW-day)	Legacy Capacity	CP	Base	CP	Base	CP	CP
RTO zone (1)	$120.00	$151.50	$149.98	$164.77	$80.00	$100.00	$ 88.32
MAAC zone	$120.00	$151.50	$149.98	$164.77	$80.00	$100.00	$ 86.04
EMAAC zone	$120.00	$151.50	$210.63	$225.42	$99.77	$119.77	$ 187.87
COMED zone	$120.00	$151.50	$200.21	$215.00	$182.77	$202.77	$ 188.12
ATSI zone	$120.00	$151.50	$149.98	$164.77	$80.00	$100.00	$ 76.53
PPL zone	$120.00	$151.50	$75.00	$164.77	$80.00	$100.00	$ 86.04

(1) Planning Year 2020-2021 includes DEOK zone which broke out from RTO zone at $130.00 per MW-day.

Our capacity sales, net of purchases, aggregated by Planning Year and capacity type through Planning Year 2020-2021, are as follows:

	2017-2018	2018-2019	2019-2020	2020-2021
Legacy/Base auction capacity sold, net (MW)	3,480	1,960	1,639	—
CP auction capacity sold, net (MW)	6,666	7,487	8,073	8,467
Bilateral capacity sold, net (MW)	2	295	200	200
Total segment capacity sold, net (MW)	10,148	9,742	9,912	8,667
Average price per MW-day	$142.22	$181.78	$132.09	$134.19

Our Kendall facility has one tolling agreement for 85 MW that expires in 2017. Effective as of the closing of the ENGIE Acquisition, we acquired a 50 percent non-operating ownership interest in the Sayreville facility.

NY/NE Segment. The NY/NE segment is comprised of 10 power generation facilities located within the ISO-NE (3,874 MW) and NYISO (1,212 MW) regions, totaling 5,086 MW of electric generating capacity.

In New England, at our Lake Road and Milford-Connecticut 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. For FCA-11, we cleared a total of 34 MW of uprates at Lake Road and Casco Bay that did not qualify for a

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seven-year rate lock. Milford-Massachusetts cleared an incremental 53 MW of new capacity in FCA-11 that qualified the entire plant for a seven-year rate lock. Milford-Massachusetts will receive the FCA-11 clearing price of $5.30 per kW-month for 202 MW through Planning Year 2026-2027. Dynegy was also awarded three municipal load contracts encompassing 65,000 accounts in the state of MA. Dynegy will begin fulfilling this 30 month obligation starting July 2017.

On February 2, 2017, FERC issued an order accepting the December 27, 2016 Compliance Filing of Atlas Power Finance, LLC, Dynegy, and ECP (collectively, “Applicants”), which proposed mitigation measures in response to market power concerns identified by FERC in its December 22, 2016 order conditionally authorizing the ENGIE Acquisition. In this order, FERC accepted, among other commitments, Applicants’ proposal to divest at least 224 MW in the Southeast New England capacity zone in ISO-NE, and Applicants’ commitment to execute agreements to sell the divested capacity by August 7, 2017. On July 10, 2017, two wholly owned indirect subsidiaries of Dynegy signed the Dighton and Milford-MA Sale Agreement (356 MW).

The following table reflects our hedging activities as of June 30, 2017:

	2017	2018	2019 to 2021
Generation volumes hedged (1)	91%	41%	7%

(1) Excludes volumes subject to tolling agreements.

NYISO Capacity Market. We have approximately 1,212 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 2016-2017	Summer 2017
Price per kW-month	$0.75	$3.00

Due to the short-term, seasonal nature of the NYISO capacity auctions, we monetize the majority of Independence’s capacity through bilateral trades. Our capacity sales, aggregated by season through Summer 2020, are as follows:

	Summer 2017	Winter 2017-2018	Summer 2018	Winter 2018-2019	Summer 2019	Winter 2019-2020	Summer 2020
Auction capacity sold (MW)	66	—	—	—	—	—	—
Bilateral capacity sold (MW)	868	930	670	380	255	118	50
Total capacity sold (MW)	934	930	670	380	255	118	50
Average price per kW-month	$3.39	$2.23	$3.50	$3.00	$3.39	$3.40	$3.45

ISO-NE Capacity Market. We have approximately 3,874 MW of power generation in ISO-NE. The most recent FCA results for ISO-NE Rest-of-Pool, in which most of our assets are located, are as follows for each Planning Year:

	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021
Price per kW-month	$3.15	$7.03	$9.55	$7.03	$5.30

Performance incentive rules will go 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. Dynegy continues to market and pursue longer term multi-year capacity transactions that extend past Planning Year 2020-2021.

Our capacity sales, aggregated by planning year through Planning Year 2020-2021, are as follows:

	2017-2018	2018-2019	2019-2020	2020-2021
Auction capacity sold (MW)	3,435	3,471	3,515	3,595
Bilateral capacity sold (MW)	148	91	45	—
Total capacity sold (MW)	3,583	3,562	3,560	3,595
Average price per kW-month	$6.98	$10.08	$7.01	$5.38

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ERCOT Segment. The ERCOT segment is comprised of six power generation facilities located within the ERCOT region, with a total generating capacity of 4,529 MW.

The following table reflects our hedging activities as of June 30, 2017:

	2017	2018	2019 to 2021
Generation volumes hedged	79%	63%	7%
Coal requirements contracted	100%	—%	—%
Coal requirements priced	100%	—%	—%
Coal transportation requirements contracted	100%	100%	—%

ERCOT Market. In addition to the energy and fuel hedges summarized in the table above we also hedge using the forward sale of ancillary services.

MISO and IPH Segments.

MISO Segment. The MISO segment is comprised of three power generation facilities located within the MISO region, with a total generating capacity of 1,913 MW. On June 9, 2016, Dynegy announced that Hennepin would receive firm transmission service for a majority of the facility into the PJM control area beginning with Planning Year 2017-2018. As of June 1, 2017, Hennepin began offering 260 MW of the facility’s energy and capacity into PJM as a block schedule. Hennepin’s remaining volume of approximately 34 MW will continue to be offered into MISO. Dynegy’s portfolio beyond 2018 is primarily open to benefit from possible future power market pricing improvements.

The following table reflects our hedging activities as of June 30, 2017:

	2017	2018	2019 to 2021
Generation volumes hedged	78%	64%	7%
Coal requirements contracted	100%	87%	53%
Coal requirements priced	100%	87%	—%
Coal transportation requirements contracted	100%	98%	96%

IPH Segment. The IPH segment is comprised of five power generation facilities, totaling 3,563 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 and energy into PJM. As of June 1, 2016, our Coffeen, Duck Creek, E.D. Edwards, and Newton facilities have 937 MW, or 26 percent of IPH’s current capacity and energy, electrically tied into PJM through pseudo-tie arrangements. Additionally, IPH has secured firm transmission as of June 1, 2017 which will allow the Joppa facility to export 240 MW into PJM.

IPH will continue to use our retail business 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.

The following table reflects our hedging activities as of June 30, 2017:

	2017	2018	2019 to 2021
Generation volumes hedged	78%	49%	22%
Coal requirements contracted	100%	50%	27%
Coal requirements priced	85%	45%	—%
Coal transportation requirements contracted	100%	100%	100%

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MISO Capacity Market. We have approximately 5,476 MW of power generation in MISO between our MISO and IPH segments. As noted above, we have secured transmission rights to deliver 1,437 MW into PJM. The capacity auction results for MISO Local Resource Zone 4, in which our assets are located, are as follows for each Planning Year:

	2017-2018
Price per MW-day	$1.50

Our MISO and IPH segments cleared no incremental volumes, in excess of our retail load obligations, in the MISO Planning Year 2017-2018 capacity auction. MISO capacity sales through Planning Year 2020-2021 are as follows:

	2017-2018	2018-2019	2019-2020	2020-2021
MISO Segment:				
Bilateral capacity sold in MISO (MW)	1,075	242	185	185
Legacy/Base auction capacity sold in PJM (MW)	207	—	—	—
CP auction capacity sold in PJM (MW)	—	—	—	38
Total MISO segment capacity sold (MW)	1,282	242	185	223
Average price per kW-month	$2.97	$2.68	$2.60	$2.65
IPH Segment:				
Bilateral capacity sold in MISO (MW)	2,350	1,943	918	789
Legacy/Base auction capacity sold in PJM (MW)	365	—	260	—
CP auction capacity sold in PJM (MW)	472	835	356	406
Total IPH segment capacity sold (MW)	3,187	2,778	1,534	1,195
Average price per kW-month	$4.42	$4.92	$4.00	$4.16

The results of the most recent MISO capacity auction further validate our strategy of right-sizing our MISO wholesale generation business to more closely match our retail business, export capacity, and wholesale origination effort. Despite a meaningful decline in the auction clearing price over the past two years, Dynegy has still been able to effectively monetize much of its available MISO capacity at attractive prices.

CAISO Segment. The CAISO segment is comprised of two power generation facilities located within the CAISO region, with a total generating capacity of 1,185 MW.

The following table reflects our hedging activities as of June 30, 2017:

	2017	2018	2019 to 2021
Generation volumes hedged	57%	—%	—%

CAISO Capacity Market. 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.

Our capacity sales, aggregated by calendar year for 2017 through 2019 for Moss Landing, are as follows:

	Remainder of 2017	2018	2019
Bilateral capacity sold (Avg. MW)	856	420	850

We have also sold seasonal capacity for Moss Landing opportunistically. Our Oakland facility operated under a reliability must run (“RMR”) contract with the CAISO for 2016 and was given notice of extension for 2017.

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Environmental and Regulatory Matters

Please read Item 1. Business—Environmental Matters in our Form 10-K and Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations-Outlook-Environmental and Regulatory Matters in our Form 10-Q for the period ended March 31, 2017 for a detailed discussion of our environmental and regulatory matters.

State-based Subsidies

On August 1, 2016, the New York Public Service Commission ("NY PSC") promulgated an Order adopting a Clean Energy Standard. The Order includes a program whereby the State will subsidize certain nuclear energy producers in New York through "zero emissions credits" ("ZECs"), which load serving entities will be required to buy, with the cost passed on to retail ratepayers. In October 2016, a group of generators including Dynegy, and our trade association, the Electric Power Supply Association, filed a lawsuit in the Southern District of New York challenging the NY PSC's ruling on constitutional grounds. On July 25, 2017, the court granted the motions of the Defendants and Exelon to dismiss the complaint. We cannot predict the outcome of that litigation, but if left unchecked, these subsidies have already and will continue to adversely affect the energy and capacity markets in NYISO by artificially suppressing prices.

In December 2016, Illinois passed legislation, the Future Energy Jobs Act ("FEJA") amending the Illinois Power Agency Act ("IPAA") to create a ZEC program for Illinois nuclear generators. The FEJA amendments to the IPAA became effective on June 1, 2017 and, unless enjoined or eliminated, the ZECs will result in an estimated $2.35 billion of payments over ten years to Exelon. In February 2017, a group of generators including Dynegy and our trade association, the Electric Power Supply Association, filed a lawsuit challenging the FEJA on constitutional grounds in the Northern District of Illinois, Eastern Division, followed by a Motion for Preliminary Injunction in March 2017. On July 14, 2017, the court granted the motions of Defendants and Exelon to dismiss the complaint and denied the motion for preliminary injunction. On July 17, 2017, we filed a notice of appeal of the July 14 Order to the United States Court of Appeals for the Seventh Circuit. We cannot predict the outcome of that litigation but, if left unchecked, these subsidies have already and will continue to adversely affect the energy and capacity markets in PJM and MISO.

The Clean Water Act

Effluent Limitation Guidelines. In April 2017, the EPA granted petitions requesting reconsideration of the Effluent Limitations Guideline ("ELG") final rule and administratively stayed the ELG rule's compliance date deadlines pending ongoing judicial review of the rule. A lawsuit has been filed challenging the administrative stay of the ELG rule. The EPA intends to decide, by fall 2017, which portions of the ELG rule, if any, that it will seek to have remanded for further rulemaking. In May 2017, the EPA issued a proposed rule to postpone compliance dates in the ELG rule until the EPA completes reconsideration of the rule.

The majority of ELG compliance expenditures are expected to occur in the 2019-2023 timeframe. As planning and work progress, we continue to review our estimates as well as timing of our capital expenditures. The following table presents the projected capital expenditures by period for ELG compliance as of June 30, 2017:

(amounts in millions)	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years	Total
ELG expenditures (1)	$ —	$ 52	$ 155	$ 38	$ 245

(1) Projections have not been adjusted to reflect the pending AES transaction. Please read Note 3—Acquisitions and Divestitures and Note 10—Joint Ownership of Generating Facilities for further discussion.

Coal Combustion Residuals

EPA CCR Rule. At this time, we estimate the cost of our compliance with the CCR rule will be approximately $285 million with the majority of the expenditures in the 2017-2023 timeframe. This estimate is reflected in our AROs.

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

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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 Six Months Ended June 30, 2017
Fair value of portfolio at December 31, 2016	$ 6
Risk management gains recognized through the statement of operations in the period, net	9
Contracts realized or otherwise settled during the period	(8)
Acquired derivatives	9
Change in collateral/margin netting	(8)
Fair value of portfolio at June 30, 2017	$ 8

The net risk management asset of $8 million is the aggregate of the following line items in our unaudited consolidated balance sheets: Current Assets—Assets from risk management activities, Other Assets—Assets from risk management activities, Current Liabilities—Liabilities from risk management activities, and Other Liabilities—Liabilities from risk management activities.

Risk Management Asset and Liability Disclosures. The following table provides an assessment of net contract values by year as of June 30, 2017, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total	2017	2018	2019	2020	2021	Thereafter
Market quotations (1)(2)	$(36)	$(24)	$(16)	$(8)	$(1)	$ 3	$ 10
Prices based on models (2)	(2)	(2)	(3)	1	2	—	—
Total (3)	$(38)	$(26)	$(19)	$(7)	$1	$ 3	$ 10

(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 $46 million of broker margin that has been netted against Risk management liabilities in 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;
- 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;

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- the effects of, or changes to the power and capacity procurement processes in the markets in which we operate;
- 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, including any impacts from the change in administration to these matters;
- projected operating or financial results, including anticipated cash flows from operations, revenues, and profitability;
- our focus on safety and our ability to operate our assets efficiently 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 performance incentives in ISO-NE;
- our ability to optimize our assets through targeted investment in cost effective technology enhancements;
- the effectiveness of our strategies to capture opportunities presented by changes in commodity prices and to manage our exposure to energy price volatility;
- efforts to secure retail sales and the ability to grow the retail business;
- efforts to identify opportunities to reduce congestion and improve busbar power prices;
- ability to mitigate impacts associated with expiring RMR and/or capacity contracts;
- expectations regarding our compliance with the Credit Agreement, including collateral demands, interest expense, any applicable financial ratios, and other payments;
- expectations regarding performance standards and capital and maintenance expenditures;
- the timing and anticipated benefits to be achieved through our company-wide improvement programs, including our PRIDE initiative;
- expectations regarding strengthening the balance sheet, managing debt maturities and improving Dynegy's leverage profile;
- expectations, timing and benefits of the AES transaction;
- efforts to divest assets and the associated timing of such divestitures, and anticipated use of proceeds from such divestitures;
- anticipated timing, outcome, and impact of expected retirements;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts; and
- expectations regarding the synergies, anticipated benefits and FERC mitigation efforts resulting from the ENGIE Acquisition.

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. The following is a discussion of the more material of these risks and our relative exposures as of June 30, 2017.

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 PJM, NY/NE, ERCOT, MISO, and CAISO 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

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10-K for a complete description of our valuation methodology. The daily VaR at June 30, 2017 compared to December 31, 2016 was lower due to a decrease in estimated volatility and price levels.

Daily and Average VaR for Risk Management Portfolios

(amounts in millions)	June 30, 2017	December 31, 2016
One day VaR—95 percent confidence level	$ 14	$ 38
One day VaR—99 percent confidence level	$ 20	$ 53
Average VaR—95 percent confidence level for the rolling twelve months ended	$ 16	$ 14

Credit Risk. The following table represents our credit exposure at June 30, 2017 associated with the mark-to-market portion of our risk management portfolio, on a net basis.

Credit Exposure Summary

(amounts in millions)	Investment Grade Quality	Non-Investment Grade Quality	Total
Type of Business:			
Financial institutions	$ 37	$ 2	$ 39
Oil and gas producers	9	—	9
Utility and power generators	17	—	17
Commercial/industrial/end users	1	—	1
Total	$ 64	$ 2	$ 66

Interest Rate Risk

We are exposed to fluctuating interest rates related to our variable rate debt obligations outstanding under our Credit Agreement. We have entered into interest rate swaps to mitigate volatility in our variable rate indices, generally LIBOR, which results in a partially fixed interest rate. Our interest rate hedging instruments are recorded at their fair value, with changes in mark to market reflected in earnings. An increase in LIBOR by 25 basis points would result in a $0.6 million increase in our annual interest expense on the unhedged portion of our indebtedness.

The absolute notional amounts associated with our interest rate contracts were as follows at June 30, 2017 and December 31, 2016, respectively:

	June 30, 2017	December 31, 2016
Interest rate swaps (in millions of U.S. dollars)	$1,965	$ 769
Fixed interest rate paid (percent)	2.38 %	3.19 %

Item 4—CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO") and our Chief Financial Officer ("CFO"), of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of June 30, 2017.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the quarter ended June 30, 2017.

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

Item 4—MINE SAFETY DISCLOSURES

Not applicable.

Item 5—OTHER INFORMATION

On May 18, 2017, Dynegy held its 2017 Annual Meeting of Stockholders. A majority of the votes present in person or represented by proxy and entitled to vote at the annual meeting voted, on an advisory basis, to hold an advisory vote to approve executive compensation annually. In line with this recommendation by our stockholders, Dynegy will include an advisory stockholder vote on executive compensation in its proxy materials every year until the next required advisory vote on the frequency of stockholder votes on executive compensation, which will occur no later than our annual meeting of stockholders in 2023.

Item 6—EXHIBITS

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

Exhibit Number	Description
*2.1	Asset Purchase Agreement dated April 21, 2017, by and among Dynegy Zimmer, LLC, Dynegy Miami Fort, LLC, AES Ohio Generation, LLC and The Dayton Power and Light Company (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2017 File No. 001-33443).
*2.2	Membership Interest Purchase Agreement, dated as of July 10, 2017, by and between Dynegy Inc. and Bruce Power, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 12, 2017 File No. 001-33443).
*2.3	Purchase and Sale Agreement, dated July 10, 2017, by and among Dynegy Resources Generating Holdco, LLC, ANP Funding I, LLC and Marco DM Holdings, L.L.C. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 13, 2017 File No. 001-33443).
10.1	Second Amendment Agreement, dated April 21, 2017, to the Letter of Credit and Reimbursement Agreement by and between Illinois Power Marketing Company and MUFG Union Bank, N.A. (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the Quarter ended March 31, 2017 of Dynegy Inc. File No. 001-33443).
**10.2	Second Amendment to Letter of Credit Reimbursement Agreement, dated July 13, 2017, between Dynegy Inc. and Macquarie Bank Limited.
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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** Filed herewith.

* Schedules and exhibits 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:	August 4, 2017	By:	/s/ CLINT C. FREELAND
			Clint C. Freeland
			Executive Vice President and Chief Financial Officer