DYNEGY INC.
Form 10-Q
November 07, 2013
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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 September 30, 2013

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

For the transition period from ________ to ________

Commission file number: 001-33443

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

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

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

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

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

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

Large accelerated filer o	Accelerated filer ý
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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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, 100,099,163 shares outstanding as of November 4, 2013.

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DEFINITIONS

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

AEM	Ameren Energy Marketing Company
AER	Ameren Energy Resources Company, LLC
AERG	Ameren Energy Resources Generating Company
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
BTA	Best Technology Available
CAIR	Clean Air Interstate Rule
CAISO	The California Independent System Operator
CARB	California Air Resources Board
CCR	Coal Combustion Residuals
CEC	California Energy Commission
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	U.S. Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CPUC	California Public Utility Commission
CS	Credit Suisse
CSAPR	Cross-State Air Pollution Rule
DCIH	Dynegy Coal Investments Holdings, LLC
DH	Dynegy Holdings, LLC (formerly known as Dynegy Holdings Inc.)
DMB	Dynegy Morro Bay, LLC
DMG	Dynegy Midwest Generation, LLC
DML	Dynegy Moss Landing, LLC
DMSLP	Dynegy Midstream Services L.P.
DPC	Dynegy Power, LLC
DYPM	Dynegy Power Marketing, LLC
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
ELG	Effluent Limitation Guidelines
EMA	Energy Management Agency Services Agreement
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles of the United States of America
GHG	Greenhouse Gas
IBEW	International Brotherhood of Electrical Workers
IMA	In-market Asset Availability
IPCB	Illinois Pollution Control Board
IPH	Illinois Power Holdings, LLC
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LC	Letter of Credit
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Pricing

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LSE	Load Serving Entity
LOLE	Loss of Load Expectation
LPG	Liquefied Petroleum Gas
LRZ	Local Resource Zones
LTPP	Long-Term Procurement Plan
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	One Million British Thermal Units
MW	Megawatts
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NM	Not Meaningful
NOL	Net operating loss
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NYISO	New York Independent System Operator
OCI	Other Comprehensive Income
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PRA	Planning Resource Auction
PRIDE	Producing Results through Innovation by Dynegy Employees
PSD	Prevention of Significant Deterioration
RFO	Request for Offer
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SCE	Southern California Edison
SEC	U.S. Securities and Exchange Commission
SO2	Sulfur Dioxide
SPDES	State Pollutant Discharge Elimination System
VaR	Value at Risk
VLGC	Very Large Gas Carrier

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

	September 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	$ 589	$ 348
Restricted cash	—	98
Accounts receivable	94	108
Accounts receivable, affiliates	—	1
Inventory	75	101
Assets from risk management activities	14	13
Assets from risk management activities, affiliates	—	4
Broker margin account	16	40
Intangible assets	127	271
Prepayments and other current assets	63	59
Total Current Assets	978	1,043
Property, Plant and Equipment	3,133	3,064
Accumulated depreciation	(164)	(42)
Property, Plant and Equipment, Net	2,969	3,022
Other Assets		
Restricted cash	—	237
Assets from risk management activities	7	—
Intangible assets	11	71
Deferred income taxes	95	95
Deferred financing costs	27	—
Other long-term assets	63	67
Total Assets	$ 4,150	$ 4,535

See the notes to condensed consolidated financial statements.

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

	September 30, 2013	December 31, 2012
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 81	$ 112
Accounts payable, affiliates	1	1
Accrued interest	11	—
Deferred income taxes	95	95
Accrued liabilities and other current liabilities	82	85
Liabilities from risk management activities	44	25
Current portion of long-term debt	7	29
Total Current Liabilities	321	347
Long-term debt	1,287	1,386
Other Liabilities		
Liabilities from risk management activities	37	42
Other long-term liabilities	217	257
Total Liabilities	$ 1,862	$ 2,032
Commitments and Contingencies (Note 13)		
Stockholders' Equity		
Common Stock, $0.01 par value, 420,000,000 shares authorized at September 30, 2013 and December 31, 2012; 100,039,215 shares and 99,999,196 shares issued and outstanding at September 30, 2013 and December 31, 2012, respectively	1	1
Additional paid-in capital	2,609	2,598
Accumulated other comprehensive income, net of tax	50	11
Accumulated deficit	(372)	(107)
Total Stockholders' Equity	$ 2,288	$ 2,503
Total Liabilities and Stockholders' Equity	$ 4,150	$ 4,535

See the notes to condensed consolidated financial statements.

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

	Successor Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Revenues	$446	$1,065	$443	$981
Cost of sales	(290)	(827)	(312)	(662)
Gross margin, exclusive of depreciation shown separately below	156	238	131	319
Operating and maintenance expense, exclusive of depreciation shown separately below	(64)	(220)	(68)	(150)
Depreciation expense	(53)	(156)	(45)	(110)
Gain on sale of assets, net	—	2	—	—
General and administrative expense	(22)	(69)	(29)	(66)
Acquisition and integration costs	(2)	(6)	—	—
Operating income (loss)	15	(211)	(11)	(7)
Bankruptcy reorganization items, net	1	(2)	18	147
Interest expense	(26)	(71)	(48)	(120)
Loss on extinguishment of debt	—	(11)	—	—
Impairment of Undertaking receivable, affiliate	—	—	—	(832)
Other income and expense, net	14	7	—	31
Income (loss) from continuing operations before income taxes	4	(288)	(41)	(781)
Income tax benefit (Note 15)	20	20	2	9
Income (loss) from continuing operations	24	(268)	(39)	(772)
Income (loss) from discontinued operations, net of tax (Note 5)	(2)	3	(2)	(420)
Net income (loss)	$22	$(265)	$(41)	$(1,192)
Earnings (Loss) Per Share (Note 17):				
Basic earnings (loss) per share:				
Income (loss) from continuing operations	$0.24	$(2.68)	N/A	N/A
Income (loss) from discontinued operations	(0.02)	0.03	N/A	N/A
Basic earnings (loss) per share	$0.22	$(2.65)	N/A	N/A
Diluted earnings (loss) per share:				
Income (loss) from continuing operations	$0.24	$(2.68)	N/A	N/A
Income (loss) from discontinued operations	(0.02)	0.03	N/A	N/A
Diluted earnings (loss) per share	$0.22	$(2.65)	N/A	N/A
Basic shares outstanding	100	100	N/A	N/A
Diluted shares outstanding	100	100	N/A	N/A

See the notes to condensed consolidated financial statements.

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

	Successor Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Net income (loss)	$22	$(265)	$(41)	$(1,192)
Other comprehensive income before reclassifications:				
Actuarial gain and plan amendments (net of tax expense of $25, $25, zero and zero, respectively)	46	46	—	—
Amounts reclassified from accumulated other comprehensive income (loss):				
Reclassification of curtailment gain included in net loss, net of tax	—	(7)	—	—
Amortization of unrecognized prior service cost and actuarial gain, net of tax	—	—	1	—
Other comprehensive income, net of tax	$46	$39	$1	$—
Total comprehensive income (loss)	$68	$(226)	$(40)	$(1,192)

See the notes to condensed consolidated financial statements.

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

	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(265)	$(1,192)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation expense	156	110
Loss on extinguishment of debt	11	—
Non-cash interest expense (benefit)	(1)	8
Amortization of intangibles	190	79
Bankruptcy reorganization items, net	—	213
Impairment of Undertaking receivable, affiliate	—	832
Risk management activities	10	(79)
Risk management activities, affiliate	—	(3)
Gain on sale of assets, net	(2)	—
Deferred income taxes	(18)	(9)
Change in value of common stock warrants	1	—
Other	8	2
Changes in working capital:		
Accounts receivable	16	9
Inventory	26	7
Broker margin account	24	(12)
Prepayments and other current assets	12	(31)
Accounts payable and accrued liabilities	(23)	26
Affiliate transactions	(1)	19
Changes in non-current assets	(7)	(16)
Changes in non-current liabilities	(5)	—
Net cash provided by (used in) operating activities	$132	$(37)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(67)	(63)
Proceeds from asset sales, net	3	—
Decrease in restricted cash	335	88
DMG Acquisition	—	256
Payments received for Undertaking, receivable affiliate	—	16
Other investing	—	3
Net cash provided by investing activities	$271	$300
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net of financing costs	1,753	—
Repayments of borrowings, including debt extinguishment costs	(1,915)	(11)
Recapitalization of Legacy Dynegy	—	27
Net cash provided by (used in) financing activities	$(162)	$16
Net increase in cash and cash equivalents	241	279
Cash and cash equivalents, beginning of period	348	398

Cash and cash equivalents, end of period	$589	$677
Other non-cash financing activity:		
DMG Acquisition	$—	$466

See the notes to condensed consolidated financial statements.

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2013 and 2012

Note 1—Basis of Presentation and Organization

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with the instructions to interim financial reporting as prescribed by the SEC. The year-end condensed consolidated balance sheet data was derived from audited consolidated financial statements but does not include all disclosures required by GAAP. The unaudited condensed consolidated financial statements contained in this report include all material adjustments of a normal recurring nature that, in the opinion of management, are necessary for a fair presentation of the results for the interim periods. These interim financial statements should be read together with the consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2012, filed with the SEC on March 14, 2013, 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 Dyne Inc. and its direct and indirect subsidiaries.

Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as two segments in our consolidated financial statements: (i) the Coal segment ("Coal") and (ii) the Gas segment ("Gas"). Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and depreciation expense. Please read Note 18—Segment Information for further discussion.

The Gas segment includes Dynegy Power, LLC ("DPC"), which owns, directly and indirectly, substantially all of our wholly-owned natural gas-fired power generation facilities.

The Coal segment includes Dynegy Midwest Generation, LLC ("DMG"), which owns, directly and indirectly, substantially all of our coal-fired power generation facilities. On September 1, 2011, DH sold 100 percent of the outstanding membership interests of Dynegy Coal Holdco, LLC ("Coal Holdco") to Legacy Dynegy (as defined below), (the "DMG Transfer"). On June 5, 2012, DH reacquired Coal Holdco (including its subsidiary, DMG) from Legacy Dynegy (the "DMG Acquisition"). Therefore, the results of our Coal segment are only included in our consolidated results subsequent to June 5, 2012. Please read Note 3—Acquisitions—DMG Acquisition for further discussion.

On September 10, 2012, the Bankruptcy Court (as defined and discussed below in Note 4—Chapter 11 Cases) entered an order confirming the Joint Chapter 11 Plan of Reorganization (the "Plan"), and on October 1, 2012, (the "Plan Effective Date"), we consummated our reorganization under Chapter 11 pursuant to the Plan and Dynegy exited bankruptcy. As a result of the application of fresh-start accounting as of the Plan Effective Date, the financial statements on or prior to October 1, 2012 are not comparable with the financial statements after October 1, 2012. References to "Successor" refer to the Company after October 1, 2012, after giving effect to the application of fresh-start accounting. References to "Predecessor" refer to the Company on or prior to October 1, 2012. Additionally, on the Plan Effective Date, the DNE Debtor Entities (as defined and discussed below in Note 4—Chapter 11 Cases) did not emerge from bankruptcy; therefore, we deconsolidated our investment in these entities as of October 1, 2012 and began accounting for our investment using the cost method. Accordingly, any activity related to our Roseton and Danskammer operations is presented in discontinued operations for all periods presented.

Merger. On September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Legacy Dynegy, with Dynegy continuing as the surviving legal entity (the "Merger"). Immediately prior to the Merger, Legacy Dynegy had no substantive operations as our power generation facilities were operated through subsidiaries of DH. Further, as a result of the DH Chapter 11 Cases (as defined in Note 4—Chapter 11 Cases) in 2011, under applicable accounting standards, Dynegy was no longer deemed to have a controlling financial interest in DH and its wholly-owned subsidiaries; therefore, DH and its consolidated subsidiaries were no longer consolidated in Dynegy's consolidated financial statements as of November 7, 2011. As a result of these factors, the accounting treatment of the Merger is reflected as a recapitalization of DH, similar to a reverse merger, whereby DH is the surviving accounting entity for financial reporting purposes. Therefore, our historical results for periods prior to the Merger are the same as DH's historical results; accordingly, we refer to Dynegy as “Legacy Dynegy” for periods prior to the Merger.

Prior to the Merger, DH was organized as a limited liability company and the capital structure of DH did not change until September 30, 2012. Although Legacy Dynegy’s shares were publicly traded, DH did not have any publicly traded shares prior to the Merger; therefore, no earnings (loss) per share is presented on our unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2012.

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2013 and 2012

Fresh-Start Accounting. On the Plan Effective Date, we applied “fresh-start accounting.” Fresh-start accounting required us to allocate the reorganization value to our assets and liabilities in a manner similar to that which is required using the acquisition method of accounting for a business combination. The financial statements of the Predecessor include the impact of the Plan provisions and the application of fresh-start accounting. As such, our financial information for the Successor is presented on a basis different from, and is therefore not comparable to, our financial information for the Predecessor for the period ended and as of October 1, 2012 or for prior periods. For further information, please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K.

Note 2—Accounting Policies

Use of Estimates

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

Accounting Standards Adopted During the Current Period

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. In February 2013, the FASB issued Accounting Standards Update (“ASU”) 2013-02—Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This new guidance requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present significant amounts reclassified out of other comprehensive income by the respective line items of net income if the amount is reclassified in its entirety. ASU 2013-02 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. Please read Note 8—Accumulated Other Comprehensive Income (Loss) for further discussion.

Disclosures about Offsetting Assets and Liabilities. In December 2011, the FASB issued ASU 2011-11—Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. The FASB added clarification to this guidance in ASU 2013-01—Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. This new guidance requires entities to disclose both gross and net information about instruments and transactions eligible for offsetting in the statement of financial position, as well as instruments and transactions subject to an agreement similar to a master netting arrangement. ASU 2011-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. Please read Note 6—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

Accounting Standards Not Yet Adopted

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

Note 3—Acquisitions

AER Transaction Agreement

On March 14, 2013, Illinois Power Holdings, LLC (“IPH”), an indirect wholly-owned subsidiary of Dynegy, entered into a definitive agreement (the “AER Transaction Agreement”) with Ameren Corporation (“Ameren”) pursuant to which IPH will, subject to the terms and conditions in the AER Transaction Agreement, acquire from Ameren 100 percent of the equity interests of Ameren Energy Resources Company, LLC ("AER") (or, following a pre-closing reorganization contemplated by Ameren, a successor thereto) for no cash or stock consideration (the "AER Acquisition"). AER and its subsidiaries consist of a majority of Ameren's merchant generation and its wholesale and retail marketing business. Pursuant to the AER Transaction Agreement, IPH will indirectly acquire AER's subsidiaries, including (i) Ameren Energy Generating Company ("Genco"), (ii) Ameren Energy Resources Generating Company ("AERG") (or, following a pre-closing reorganization contemplated by Ameren, a successor thereto), (iii) Ameren Energy Fuels and Services Company and (iv) Ameren Energy Marketing Company ("AEM"). Dynegy Inc. has provided a limited guaranty of certain obligations of IPH up to $25 million (the "Limited Guaranty") as described below.

The transaction does not include AER's gas-fired power generation facilities: Elgin, Gibson City and Grand Tower (the "Put Assets"). AERG, Genco and Ameren Energy Medina Valley Cogen L.L.C. ("Medina Valley"), an affiliate of AER that IPH will not be acquiring in the transaction, entered into an amendment to a put option agreement (the "Put Option Agreement") whereby the Put Assets will be sold by Genco, subject to approval by FERC, to Medina Valley for a minimum of $133 million (the "Put Transaction"). On October 11, 2013, the Put Transaction was consummated following receipt of FERC approval. Pursuant to the AER Transaction Agreement, Ameren will cause Medina Valley to pay Genco minimum after-tax proceeds of approximately $138 million. Additionally, Genco may receive after-tax net proceeds realized in excess of $138 million following the closing of the sale of the Put Assets by Medina Valley to Rockland Capital.

In connection with the AER Acquisition, Ameren will retain certain historical obligations of AER and its subsidiaries, including certain historical environmental and tax liabilities. Genco's approximately $825 million in aggregate principal amount of notes will remain outstanding as an obligation of Genco. The debt bears interest at rates from 6.30 percent to 7.95 percent and matures between 2018 and 2032. Additionally, Ameren is required to maintain its existing credit support, including all of its collateral obligations with respect to AEM, for a period not to exceed two years.

In addition to the Put Transaction proceeds, Ameren is required at closing to ensure that a minimum of $85 million of cash, plus approximately $8 million primarily for the proceeds of certain real estate sales, is available at AER and its subsidiaries. Approximately $70 million of cash, plus the proceeds of the Put Transaction described above will be held at Genco.

The AER Transaction Agreement includes customary representations, warranties and covenants by the parties. The closing of the transaction is expected to occur in December 2013, subject to certain conditions, including (i) consummation of the Put Transaction under the Put Option Agreement, which closed on October 11, 2013; (ii) approval of FERC under Section 203 of the Federal Power Act, as amended, which occurred on October 11, 2013 ("FERC Approval"); (iii) approval of certain license transfers by the Federal Communications Commission, which occurred in August 2013 ("FCC Approval"); (iv) approval by the Illinois Pollution Control Board (the "IPCB") of the transfer to IPH of AER's air variance; (v) no injunction or other orders preventing the consummation of the transactions under the AER Transaction Agreement; (vi) the continuing accuracy of each party's representations and warranties; and (vii) the satisfaction of other conditions. On June 6, 2013, the IPCB rejected, on procedural grounds, AER's and IPH's motion to transfer the air variance, which granted AER a temporary exemption for the coal plants of its subsidiaries from certain air pollution limitations under the Illinois' Multi-Pollutant Standard. The IPCB indicated that IPH may file its own request for variance relief. IPH and AER are pursuing such relief, and on July 22, 2013 IPH and certain co-petitioners filed their request for variance relief and a hearing was held on September 17, 2013. The IPCB is expected to make its decision on that request on or before November 21, 2013.

Each party has agreed to indemnify the other for breaches of representations and warranties, breaches of covenants and certain other matters, subject to certain exceptions. The AER Transaction Agreement contains certain termination rights for both IPH and Ameren, including if the closing does not occur within 12 months following the date of the AER Transaction Agreement.

The AER Transaction Agreement provides for the payment of a termination fee by each party under specific circumstances. In certain circumstances, including failure to receive FERC Approval, IPH must pay a termination fee of $25 million to Ameren.

Concurrently with the execution of the AER Transaction Agreement, Dynegy Inc. entered into the Limited Guaranty, capped at $25 million in favor of Ameren, pursuant to which we will guarantee payout by IPH of any required termination fee and, for a period of two years after the closing (subject to certain exceptions), up to $25 million with respect to IPH’s indemnification obligations and certain reimbursement obligations under the AER Transaction Agreement.

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2013 and 2012

DMG Acquisition

On June 5, 2012, pursuant to a settlement agreement entered into with certain of DH's creditors, Legacy Dynegy and DH consummated the DMG Acquisition. The DMG Acquisition was accounted for as a business combination in DH's financial statements as Legacy Dynegy deconsolidated DH, effective November 7, 2011, as a result of the DH Chapter 11 Cases. Accordingly, the assets acquired and liabilities assumed were recognized at their fair value as of the acquisition date.

The purchase price was approximately $466 million. Consideration given by DH consisted of (i) approximately $402 million for the fair value of the Undertaking receivable, affiliate that was extinguished in connection with the transaction and (ii) approximately $64 million for the fair value of the Administrative Claim issued to Legacy Dynegy in the DH Chapter 11 Cases. As a result of entering into the settlement agreement, the Undertaking receivable was impaired to $418 million as of March 31, 2012, resulting in a charge of approximately $832 million. The carrying value of the Undertaking was adjusted to the value received in the DMG Acquisition plus interest payments received subsequent to March 31, 2012.

Pro Forma Results. The unaudited pro forma financial results for the nine months ended September 30, 2012 show the effect of the DMG Acquisition as if the acquisition had occurred as of January 1, 2012.

(amounts in millions)	Predecessor Nine Months Ended September 30, 2012	
Revenues	$ 1,211	
Loss from continuing operations	$ (27	)
Loss from discontinued operations	$ (420	)
Net loss	$ (447	)

Note 4—Chapter 11 Cases

On November 7, 2011, DH and four of its wholly-owned subsidiaries, Dynegy Northeast Generation, Inc. ("DNE"), Hudson Power, L.L.C. ("Hudson"), Dynegy Danskammer, L.L.C. ("Danskammer") and Dynegy Roseton, L.L.C. ("Roseton", and together with DH, DNE, Hudson and Danskammer, the "DH Debtor Entities") filed voluntary petitions (the "DH Chapter 11 Cases") for relief under Chapter 11 of Title 11 of the United States Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of New York, Poughkeepsie Division (the "Bankruptcy Court"). The DH Chapter 11 Cases were jointly administered for procedural purposes only. On July 6, 2012, Legacy Dynegy filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court (the "Dynegy Chapter 11 Case," and together with the DH Chapter 11 Cases, the "Chapter 11 Cases"). Only Legacy Dynegy and the DH Debtor Entities filed voluntary petitions for relief under the Bankruptcy Code and none of our other direct or indirect subsidiaries are or were debtors thereunder.

On the Plan Effective Date, we consummated our reorganization under Chapter 11 pursuant to the Plan and Dynegy exited bankruptcy. DNE, Hudson, Danskammer and Roseton (the "DNE Debtor Entities") remain in Chapter 11 bankruptcy. As a result, we deconsolidated the DNE Debtor Entities on the Plan Effective Date and began accounting for our investment using the cost method. Accordingly, any activity related to our Roseton and Danskammer operations is reported in discontinued operations for all periods presented. Please read Note 5—Discontinued Operations for further discussion.

As of September 30, 2013 and December 31, 2012, we had approximately $1 million in net payables and less than $1 million in net receivables, respectively, from the DNE Debtor Entities related to the Service Agreements included in our unaudited condensed consolidated balance sheets. We account for our investment in the DNE Debtor Entities using the cost method and have a carrying amount of zero. Our maximum loss exposure related to our investment in the DNE Debtor Entities is limited to our net receivables as we have no obligation to provide funding to the DNE Debtor Entities on an ongoing basis.

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For the three and nine months ended and as of September 30, 2013, we do not have any subsidiaries under Chapter 11 protection included in our unaudited condensed consolidated financial statements. The condensed combined financial statements of the Debtor Entities included in our results for the three and nine months ended September 30, 2012 are set forth below:

Condensed Combined Statements of Operations of the Debtor Entities

(amounts in millions)	Predecessor Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Revenues	$—	$—
Cost of sales	—	—
Operating expense	—	—
General and administrative expense	(3)	(7)
Operating loss	(3)	(7)
Bankruptcy reorganization items, net	18	147
Equity losses	(46)	(1,373)
Impairment of Undertaking receivable, affiliate	—	(832)
Other income and expense, net	(10)	1,284
Income tax benefit	2	9
Loss from continuing operations	(39)	(772)
Loss from discontinued operations	(2)	(420)
Net loss	$(41)	$(1,192)

Condensed Combined Statement of Cash Flows of the Debtor Entities

(amounts in millions)	Predecessor Nine Months Ended September 30, 2012
Net cash provided by:	
Operating activities	$ 32
Investing activities	27
Financing activities	200
Net increase in cash and cash equivalents	259
Cash and cash equivalents, beginning of period	33
Cash and cash equivalents, end of period	$ 292

Basis of Presentation. The condensed combined financial statements only include the financial statements of the DH Debtor Entities. Transactions among the DH Debtor Entities are eliminated in the condensed combined financial statements.

Interest Expense. The DH Debtor Entities discontinued recording interest on unsecured liabilities subject to compromise (“LSTC”) effective November 8, 2011. Contractual interest on LSTC not reflected in the condensed combined financial statements was approximately $74 million and $217 million for the three and nine months ended September 30, 2012, respectively.

Bankruptcy Reorganization Items, net. Bankruptcy reorganization items, net represent the direct and incremental costs of bankruptcy, such as professional fees, pre-petition liability claim adjustments and losses related to terminated contracts that are probable and can be estimated. Bankruptcy reorganization items, net, as shown in the condensed combined statement of operations above, consist of expense or income incurred or earned as a direct and incremental result of the bankruptcy filings.

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The table below lists the significant items within this category:

(amounts in millions)	Predecessor Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Adjustments of estimated allowable claims:		
DNE leases (1)	$—	$(395)
Subordinated notes (2)	—	161
Write-off of note payable, affiliate (3)	—	10
Other	(1)	(5)
Total adjustments for estimated allowable claims	(1)	(229)
Change in value of Administrative Claim (4)	26	17
Professional fees (5)	(7)	(40)
Total Bankruptcy reorganization items, net	18	(252)
Bankruptcy reorganization items, net included in discontinued operations	—	399
Total Bankruptcy reorganization items, net in continuing operations	$18	$147

(1) Amount represents adjustments to our estimate of the probable allowed claim associated with the DNE leases as a result of entering into the Settlement Agreement. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K for further discussion.

(2) The estimated allowable claims related to the Subordinated Capital Income Securities were adjusted in the second quarter 2012 based on the terms of the Settlement Agreement, as amended. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K for further discussion.

(3) It was determined that no claim related to the Note payable, affiliate would be made. Therefore, the estimated amount was reduced to zero.

(4) The Administrative Claim was issued on the effective date of the Settlement Agreement. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting—Settlement Agreement and Plan Support Agreement in our Form 10-K for further discussion.

(5) Professional fees relate primarily to the fees of attorneys and consultants working directly on the Chapter 11 Cases.

Note 5—Discontinued Operations

Discontinued Operations

The DNE Debtor Entities remain in Chapter 11 bankruptcy and continue to operate their businesses as "debtors-in-possession." As a result, Dynegy deconsolidated the DNE Debtor Entities, effective October 1, 2012. The Bankruptcy Court approved agreements to sell the Danskammer and Roseton facilities for a combined cash purchase price of $23 million and the assumption of certain liabilities (the "Facilities Sale Transactions"). On April 30, 2013, we completed the sale of the Roseton facility. The Bankruptcy Court ordered the original purchaser of the Danskammer facility to close the transaction by July 31, 2013. The Danskammer facility sale did not close by July 31, 2013 as ordered by the Bankruptcy Court and Danskammer terminated its obligations under the original Danskammer asset purchase agreement. On August 29, 2013, the Bankruptcy Court approved the sale of the Danskammer assets to a new purchaser at the same price and on terms similar to the original Danskammer asset purchase agreement. On November 1, 2013 the Danskammer assets were sold to Helios Power Capital, LLC. On November 4, 2013, the DNE Joint Plan of Liquidation became effective and Hudson Power, Dynegy Danskammer and Dynegy Roseton were deemed to have been merged into DNE or dissolved. The proceeds from the Facilities Sale Transactions have been distributed pursuant to the Joint Plan of Liquidation, including any modification thereto.

Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting and Note 6—Dispositions and Discontinued Operations in our Form 10-K for further discussion. Any activity related to DNE is reported as discontinued operations for all periods presented.

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Summary. The amounts in the table below reflect the operating results of the businesses reported as discontinued operations:

(amounts in millions)	Successor Three Months Ended September 30, 2013	Successor Nine Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Predecessor Nine Months Ended September 30, 2012
Revenues	$—	$(2)	$34	$61
Income (loss) from operations before taxes	$—	$5	$(2)	$(420)
Income (loss) from operations after taxes	$(2)	$3	$(2)	$(420)

Note 6—Risk Management Activities, Derivatives and Financial Instruments

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

Our commodity risk management strategy 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 condensed consolidated statements of operations. We also manage commodity price risk by entering into capacity forward sales arrangements, tolling arrangements, RMR contracts, fixed price coal purchases and other arrangements that do not receive recurring fair value accounting treatment because these arrangements do not meet the definition of a derivative or are designated as "normal purchase, normal sale." As a result, the gains and losses with respect to these arrangements are not reflected in the unaudited condensed consolidated statements of operations until the delivery occurs.

Quantitative Disclosures Related to Financial Instruments and Derivatives

The following disclosures and tables present information concerning the impact of derivative instruments on our unaudited condensed consolidated balance sheets and statements of operations. In the table below, commodity contracts primarily consist of derivative contracts related to our power generation business that we have not designated as accounting hedges that are entered into for purposes of economically hedging future fuel requirements and sales commitments and securing commodity prices. Interest rate contracts are entered into for purposes of reducing our exposure to interest rate fluctuations on our variable rate debt. Common stock warrants were issued in connection with our emergence from bankruptcy and allow the holder to purchase, on a one-to-one basis, one common share of Dynegy common stock at $40 per share. We elect not to designate any of our derivatives as accounting hedges. As of September 30, 2013, our commodity derivatives were comprised of both purchases and sales of commodities. As of September 30, 2013, we had net purchases and sales of derivative contracts outstanding in the following quantities:

Contract Type (dollars and quantities in millions)	Hedge Designation	Quantity Purchases (Sales)	Unit of Measure	Fair Value (1) Asset (Liability)
Commodity contracts:				
Electricity derivatives (2)	Not designated	(18)	MWh	$6
Natural gas derivatives (2)	Not designated	119	MMBtu	$(25)
Heat rate derivatives	Not designated	(1)/3	MWh/MMBtu	$1

Emissions derivatives	Not designated	2	Metric Ton	$(3)
Interest rate contracts:				
Interest rate swaps	Not designated	796	Dollars	$(47)
Common stock warrants	Not designated	16	Warrants	$(21)

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(1) Includes both asset and liability risk management positions, but excludes margin and collateral netting, as discussed below.
(2) Mainly comprised of swaps, options and physical forwards.

Derivatives on the Balance Sheet. We execute a significant volume of transactions through futures clearing managers. Our daily cash payments (receipts) with our futures clearing managers consist of three parts: (i) fair value of open positions (exclusive of options) ("Daily Cash Settlements"); (ii) initial margin requirements of open positions ("Initial Margin"); and (iii) fair value related to options ("Options," and collectively with Daily Cash Settlements and Initial Margin, "Margin"). In addition to these transactions we execute through the futures clearing managers, we also execute transactions through multiple bilateral counterparties. Our transactions with these counterparties are collateralized using cash collateral ("Collateral"), letters of credit and first liens. We elect to offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement, where the right of offset exists. We also offset Margin and Collateral paid to or received from all counterparties against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. As a result, the consolidated balance sheets present derivative assets and liabilities, as well as cash paid to or received from all counterparties against those positions, on a net basis.

The following tables present the fair value and balance sheet classification of derivatives in the unaudited condensed consolidated balance sheet as of September 30, 2013 and the consolidated balance sheet as of December 31, 2012 segregated by type of contract segregated by assets and liabilities. As of September 30, 2013 and December 31, 2012, there were no gross amounts available to be offset that were not offset in our consolidated balance sheets.

		September 30, 2013			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$62	$(41)	$—	$21
Total derivative assets		$62	$(41)	$—	$21
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(83)	$41	$8	$(34)
Interest rate contracts	Liabilities from risk management activities	(47)	—	—	(47)
Common stock warrants	Other long-term liabilities	(21)	—	—	(21)
Total derivative liabilities		$(151)	$41	$8	$(102)
Total derivatives		$(89)	$—	$8	$(81)

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		December 31, 2012			
			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	$61	$(48)	$—	$13
Commodity contracts, affiliates	Assets from risk management activities, affiliates	4	—	—	4
Total derivative assets		$65	$(48)	$—	$17
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(77)	$48	$8	$(21)
Interest rate contracts	Liabilities from risk management activities	(46)	—	—	(46)
Common stock warrants	Other long-term liabilities	(20)	—	—	(20)
Total derivative liabilities		$(143)	$48	$8	$(87)
Total derivatives		$(78)	$—	$8	$(70)

The following table summarizes our cash collateral posted as of September 30, 2013 and December 31, 2012, along with the location on the balance sheet and the amount applied against our short-term risk management liabilities.

	September 30, 2013		December 31, 2012	
Location on balance sheet	Collateral posted	Amount applied against short-term risk management liabilities	Collateral posted	Amount applied against short-term risk management liabilities
(amounts in millions)				
Broker margin	$23	$7	$44	$4
Prepayments and other current assets	$3	$1	$17	$4

Impact of Derivatives on the Consolidated Statements of Operations

The following discussion and table presents the location and amount of gains and losses on derivative instruments in our consolidated statements of operations. We had no derivatives that were designated in qualifying hedging relationships during the three and nine months ended September 30, 2013 and 2012.

Financial Instruments Not Designated as Hedges. We elect not to designate derivatives related to our power generation business and interest rate instruments as cash flow or fair value hedges. Thus, we account for changes in the fair value of these derivatives within the consolidated statements of operations (herein referred to as "mark-to-market" accounting treatment). As a result, these mark-to-market gains and losses are not reflected in the unaudited condensed consolidated statements of operations in the same period as the underlying activity for which the derivative instruments serve as economic hedges.

For the three and nine months ended September 30, 2013, Revenues include unrealized mark-to-market losses of $29 million and unrealized mark-to-market gains of $8 million, respectively, related to our commodity derivatives compared to unrealized mark-to-market gains of $33 million and $103 million for the three and nine months ended

September 30, 2012, respectively. For the three and nine months ended September 30, 2013, Interest expense includes unrealized mark-to-market losses of $5 million and $1 million, respectively, related to our interest rate derivatives compared to unrealized mark-to-market losses of $20 million and $33 million for the three and nine months ended September 30, 2012, respectively.

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The realized and unrealized impact of derivative financial instruments on our unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2013 and 2012 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross margin we expect to realize when the underlying physical transactions settle and interest payments are made.

Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Successor Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
(amounts in millions)					
Commodity contracts	Revenues	$(2)	$(52)	$(36)	$(60)
Commodity contracts, affiliates	Revenues	$—	$(2)	$—	$(6)
Interest rate contracts	Interest expense	$(6)	$(3)	$(22)	$(33)
Common stock warrants	Other income (expense), net	$8	$(1)	$—	$—

Note 7—Fair Value Measurements

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

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 2012 and are presented on a gross basis before consideration of amounts netted under master netting agreements and the application of collateral and margin paid. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value as of September 30, 2013			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$42	$8	$50
Natural gas derivatives	—	10	—	10
Heat rate derivatives	—	—	1	1
Emissions derivatives	—	1	—	1
Total assets from commodity risk management activities	$—	$53	$9	$62
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(28)	$(16)	$(44)

Natural gas derivatives	—	(35)	—	(35)
Emissions derivatives	—	(4)	—	(4)
Total liabilities from commodity risk management activities	—	(67)	(16)	(83)
Liabilities from interest rate contracts	—	(47)	—	(47)
Liabilities from outstanding common stock warrants	(21)	—	—	(21)
Total liabilities	$(21)	$(114)	$(16)	$(151)

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	Fair Value as of December 31, 2012			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$37	$11	$48
Natural gas derivatives	—	14	—	14
Heat rate derivatives	—	—	3	3
Total assets from commodity risk management activities	$—	$51	$14	$65
Liabilities:				
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(50)	$(6)	$(56)
Natural gas derivatives	—	(20)	—	(20)
Heat rate derivatives	—	—	(1)	(1)
Total liabilities from commodity risk management activities	—	(70)	(7)	(77)
Liabilities from interest rate contracts	—	(46)	—	(46)
Liabilities from outstanding common stock warrants	(20)	—	—	(20)
Total liabilities	$(20)	$(116)	$(7)	$(143)

Level 3 Valuation Methods. The electricity derivatives classified within Level 3 are primarily financial swaps executed in illiquid trading locations, capacity contracts, off-peak power options and FTRs. The curves used to generate the fair value of the financial swaps are based on basis adjustments applied to forward curves for liquid trading points, while the curves for the capacity deals are based upon auction results in the marketplace, which are infrequently executed. Off-peak power options are valued using a Black-Scholes model which uses forward power prices and market implied volatility. The forward market price of FTRs is derived using historical congestion patterns within the marketplace and heat rate derivative valuations are derived using a Black-Scholes spread model, which uses forward natural gas and power prices, market implied volatilities and modeled power/natural gas correlation values.

Sensitivity to Changes in Significant Unobservable Inputs for Level 3 Valuations. The significant unobservable inputs used in the fair value measure of our commodity instruments categorized within Level 3 of the fair value hierarchy are estimates of future price correlation, future market volatility, forward congestion power price spreads and illiquid power location pricing basis to liquid locations. These estimates are generally independent of each other. Volatility curves and power price spreads are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price or volatility of the spread on a long/short position in isolation would result in a higher/lower fair value measurement.

The significant unobservable inputs used in the valuation of Dynegy’s contracts classified as Level 3 as of September 30, 2013 are as follows:

Transaction Type	Quantity	Unit of Measure	Net Fair Value	Valuation Technique	Significant Unobservable Inputs	Significant Unobservable Inputs Range
(dollars in millions)						
Electricity derivatives:						
	(11)	Million MWh	$(6)		Basis spread	$6.00-$10.00

Forward contracts—power (1)				Basis spread + liquid location		
Capacity options	(1,100)	MW month	$ —	Option models	Option price	$0.00-$0.10
Off-peak power options	(162)	Thousand MWh	$ —	Option models	Power price volatility	13%-33%
FTRs	4	Million MWh	$ (2)	Historical congestion	Forward price	$1.00-$11.00
Heat rate derivatives	3	Million MWh	$ —	Option models	Gas/power price correlation	57%-87%
	(399)	Thousand MMBtu	$ 1		Power price volatility	13%-33%

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

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

	Successor Three Months Ended September 30, 2013		
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Total
Balance at June 30, 2013	$(3)	$1	$(2)
Total gains (losses) included in earnings	(5)	1	(4)
Settlements (1)	—	(1)	(1)
Balance at September 30, 2013	$(8)	$1	$(7)
Unrealized gains (losses) relating to instruments held as of September 30, 2013	$(5)	$1	$(4)

	Successor Nine Months Ended September 30, 2013		
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Total
Balance at December 31, 2012	$5	$2	$7
Total losses included in earnings	(7)	—	(7)
Settlements (1)	(6)	(1)	(7)
Balance at September 30, 2013	$(8)	$1	$(7)
Unrealized losses relating to instruments held as of September 30, 2013	$(7)	$—	$(7)

	Predecessor Three Months Ended September 30, 2012				
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Administrative Claim	Interest Rate Swaps (2)	Total
Balance at June 30, 2012	$8	$(8)	$ (73)	$(25)	$(98)
Total gains (losses) included in earnings, net of affiliates	(1)	(1)	26	(12)	12
Settlements, net of affiliates (1)	(2)	7	—	—	5
Balance at September 30, 2012	$5	$(2)	$ (47)	$(37)	$(81)
Unrealized gains (losses) relating to instruments (net of affiliates) held as of September 30, 2012	$(15)	$(1)	$ 26	$(12)	$(2)

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	Predecessor				
	Nine Months Ended September 30, 2012				
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Administrative Claim	Interest Rate Swaps (2)	Total
Balance at December 31, 2011	$20	$(17)	$ —	$(6)	$(3)
Total gains (losses) included in earnings, net of affiliates	(33)	1	17	(24)	(39)
Settlements, net of affiliates (1)	14	14	—	—	28
Issuance of Administrative Claim	—	—	(64)	—	(64)
DMG Acquisition	4	—	—	(7)	(3)
Balance at September 30, 2012	$5	$(2)	$ (47)	$(37)	$(81)
Unrealized gains (losses) relating to instruments (net of affiliates) held as of September 30, 2012	$(11)	$1	$ 17	$(28)	$(21)

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

(2) The interest rate contracts classified within Level 3 in the predecessor period include an implied credit fee that impacted the day one value of the instruments. We revalued the credit fee in connection with the application of fresh-start accounting. As a result, these instruments are classified within Level 2 in the successor period.

Gains and losses (realized and unrealized) for Level 3 recurring items are included in Revenues and Interest expense on the unaudited condensed consolidated statements of operations for commodity derivatives and interest rate swaps, respectively. We believe an analysis of commodity instruments classified as Level 3 should be undertaken with the understanding that these items generally serve as economic hedges of our power generation portfolio. We did not have any transfers between Level 1, Level 2 and Level 3 for the three and nine months ended September 30, 2013 and 2012.

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

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

Fair Value of Financial Instruments. We have determined the estimated fair value amounts using available market information and selected valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies could have a material effect on the estimated fair value amounts.

The carrying values of financial assets and liabilities (cash, accounts receivable, restricted cash and accounts payable) not presented in the table below approximate fair values due to the short-term maturities of these instruments. Unless otherwise noted, the fair value of debt as reflected in the table has been calculated based on the average of certain available broker quotes as of September 30, 2013 and December 31, 2012, respectively.

	September 30, 2013		December 31, 2012	
(amounts in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Interest rate derivatives not designated as accounting hedges (1)	$(47)	$(47)	$(46)	$(46)
	$(21)	$(21)	$(12)	$(12)

Commodity-based derivative contracts not designated as accounting hedges (1)				
DPC Credit Agreement, due 2016 (2)	$—	$—	$(880)	$(874)
DMG Credit Agreement, due 2016 (3)	$—	$—	$(535)	$(537)
Tranche B-2 Term Loan, due 2020 (4)	$(794)	$(795)	$—	$—
5.875% Senior Notes, due 2023 (5)	$(500)	$(465)	$—	$—
Common stock warrants	$(21)	$(21)	$(20)	$(20)

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(1) Included in both current and non-current assets and liabilities on the unaudited condensed consolidated balance sheets.

(2) Carrying amount includes an unamortized premium of $43 million at December 31, 2012. The fair value of the DPC Credit Agreement is classified within Level 2 of the fair value hierarchy. Please read Note 12—Debt for further discussion.

(3) Carrying amount includes an unamortized premium of $18 million as of December 31, 2012. The fair value of the DMG Credit Agreement is classified within Level 2 of the fair value hierarchy. Please read Note 12—Debt for further discussion.

(4) Carrying amount includes an unamortized discount of $4 million as of September 30, 2013. The fair value of the Tranche B-2 Term Loan is classified within Level 2 of the fair value hierarchy. Please read Note 12—Debt for further discussion.

(5) The fair value of the Senior Notes is classified within Level 2 of the fair value hierarchy. Please read Note 12—Debt for further discussion.

Note 8—Accumulated Other Comprehensive Income (Loss)

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

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012
Beginning of period	$11	$1
Current period other comprehensive income:		
Actuarial gain and plan amendments (net of tax of $25 and zero, respectively) (1)	46	—
Other comprehensive income before reclassifications	46	—
Amounts reclassified from accumulated other comprehensive income (loss) (2)	(7)	—
Net current period other comprehensive income	39	—
DMG Acquisition	—	(25)
End of period	$50	$(24)

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(1) As a result of amendments to certain of our pension and other post-employment benefit plans, we remeasured the affected plans during the third quarter 2013. Please read Note 16—Pension and Other Post-Employment Benefit Plans for further discussion.

(2) Amounts reclassified from accumulated other comprehensive income (loss) relate to the DNE pension curtailment gain and are recorded in Income (loss) from discontinued operations, net of tax on our unaudited condensed consolidated statements of operations. Please read Note 16—Pension and Other Post-Employment Benefit Plans for further discussion.

Note 9—Inventory

A summary of our inventories is as follows:

(amounts in millions)	September 30, 2013	December 31, 2012
Materials and supplies	$45	$46
Coal	23	52
Fuel oil	3	3
Emissions allowances	4	—
Total	$75	$101

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Note 10—Asset Retirement Obligations

We record the present value of our legal obligations to retire tangible, long-lived assets on our balance sheets as liabilities when the liability is incurred. Significant judgment is involved in estimating future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. A summary of changes in our AROs is as follows:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012
Beginning of period	$ 83	$ 50
Accretion expense	4	3
Revision of previous estimate (1)	36	(16)
DMG Acquisition (2)	—	53
Expenditures	(3)	(1)
End of period	$ 120	$ 89

(1) The increase in our AROs for the Successor period primarily relates to revised estimates based on observed trends in Illinois related to ash pond closures and groundwater monitoring. The reduction in our AROs for the Predecessor period was based on revised cost estimates related to the demolition of our South Bay facility.

(2) As a result of the DMG Transfer on September 1, 2011, the AROs related to our Coal segment were transferred from DH to Legacy Dynegy and subsequently, as a result of the DMG Acquisition, the AROs were transferred back to DH on June 5, 2012.

Note 11—Intangible Assets and Liabilities

A summary of changes in our intangible assets and liabilities is as follows:

(amounts in millions)	Gas Revenue Contracts	Coal Contracts	Gas Transport	Total
Balance at December 31, 2012	$ 202	$ 115	$ (22)	$ 295
Amortization	(101)	(95)	6	(190)
Balance at September 30, 2013 (1)	$ 101	$ 20	$ (16)	$ 105

(1) The total amount of $105 million consists of $127 million in short-term Intangible assets, $11 million in long-term Intangible assets, $15 million in Accrued liabilities and other current liabilities and $18 million in Other long-term liabilities on our unaudited condensed consolidated balance sheet.

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Note 12—Debt

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

(amounts in millions)	September 30, 2013	December 31, 2012
DPC Credit Agreement, due 2016 (1)	$—	$ 837
DMG Credit Agreement, due 2016 (1)	—	517
Tranche B-2 Term Loan, due 2020 (2)	798	—
Revolving Facility (2)	—	—
5.875% Senior Notes, due 2023 (3)	500	—
	1,298	1,354
Unamortized (discount) premium on debt, net	(4)	61
	1,294	1,415
Less: Amounts due within one year, including unamortized (discount) premium on debt, net of ($1) million and $15 million, respectively	7	29
Total Long-term debt	$ 1,287	$ 1,386

(1) Please read Note 18—Debt—DPC and DMG Credit Agreements in our Form 10-K for further discussion.

(2) On April 23, 2013, we entered into the Credit Agreement. Please read Credit Agreement below for further discussion.

(3) On May 20, 2013, we issued the Senior Notes. Please read Senior Notes below for further discussion.

Credit Agreement

On April 23, 2013, Dynegy (the “Borrower”) entered into a $1.775 billion credit agreement that consists of (i) a $500 million seven-year senior secured term loan B facility (the “Tranche B-1 Term Loan”), (ii) an $800 million seven-year senior secured term loan B facility (the “Tranche B-2 Term Loan” and, together with the Tranche B-1 Term Loan, the “Term Facilities”) and (iii) a $475 million five-year senior secured revolving credit facility (the “Revolving Facility,” and collectively with the Term Facilities, the “Credit Agreement”). The Term Facilities were offered to investors below par with an original issue discount of 99.5. The Term Facilities bear interest at LIBOR plus 3.00 percent per annum with a one percent floor. The Term Facilities mature April 23, 2020 and will amortize in equal quarterly installments in aggregate annual amounts equal to 1.00 percent of the original principal amount with the balance payable on the maturity date. The Revolving Facility bears interest, initially, at LIBOR plus 2.75 percent per annum, with step downs based on a Senior Secured Leverage Ratio (as defined in the Credit Agreement) and matures April 23, 2018. The Revolving Facility has a commitment fee of 0.50 percent on the unutilized portion of the facility, with step downs based on a Senior Secured Leverage Ratio. The commitment fees are due and payable quarterly in arrears. As discussed further below, the Tranche B-1 Term Loan was repaid on May 20, 2013 in connection with the issuance of the Senior Notes.

At September 30, 2013, there were no amounts drawn on the Revolving Facility; however, we had outstanding letters of credit of approximately $183 million, which reduces the amount available under the Revolving Facility.

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All obligations of the Borrower under the Credit Agreement are unconditionally guaranteed on a senior basis by certain existing and subsequently acquired or organized direct and indirect material domestic restricted subsidiaries of the Borrower on a joint and several basis (the "Guarantors"). The obligations under the Credit Agreement and certain of our hedging obligations are secured by a perfected first-priority lien on and security interests in substantially all of the present and future assets of the Borrower and each Guarantor (collectively, the "Collateral"). The Collateral excludes certain assets, including, following the consummation of the AER Acquisition, AER and its subsidiaries and their direct and indirect holding companies.

The Credit Agreement contains customary events of default and affirmative and negative covenants, subject to certain specified exceptions, including a Senior Secured Leverage Ratio calculated on a rolling four quarters basis. Under the Credit Agreement, if Dynegy has utilized 25 percent or more of its Revolving Facility, Dynegy must be in compliance with the following ratios for the respective periods:

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

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

Our revolver usage was 39 percent of the aggregate revolver commitment due to outstanding letters of credit, and we were therefore required to test the covenant. Based on the calculation outlined in the Credit Agreement, we are in compliance at September 30, 2013.

Borrowings under the Credit Agreement, together with a portion of our cash on hand, were used to repay in full and terminate commitments under: (i) the DPC Credit Agreement and DMG Credit Agreement, (ii) the DPC Revolving Credit Agreement, (iii) the DPC Letter of Credit Reimbursement and Collateral Agreement, (iv) the DMG Letter of Credit Reimbursement and Collateral Agreement, (v) the Dynegy Letter of Credit Reimbursement and Collateral Agreement and (vi) the Dynegy CS Letter of Credit Agreement. As a result of repaying and terminating these credit agreements, all of the restricted cash on hand was released. None of the borrowings under the Credit Agreement were classified as restricted cash. In connection with the refinancing, the bankruptcy remoteness provisions of certain of our subsidiaries and the related ring-fenced structure at our Coal and Gas segments were removed.

Senior Notes

On May 20, 2013, Dynegy and its current and future wholly-owned domestic subsidiaries (the "Subsidiary Guarantors") entered into an indenture (the "Indenture") pursuant to which Dynegy issued $500 million in aggregate principal amount of unsecured senior notes (the "Senior Notes") at par. The Senior Notes bear interest at a rate of 5.875 percent per annum. The Senior Notes mature on June 1, 2023.

The Indenture limits, among other things, Dynegy's ability or any of its Subsidiary Guarantors to (i) create liens upon any principal property to secure debt for borrowed money and (ii) consolidate, merge or sell all or substantially all of their assets. In the event of a Change of Control (as defined in the Indenture), Dynegy will be required to make an offer to each holder of the Senior Notes to repurchase all or any part of that holder's Senior Notes at a repurchase price in cash equal to 101 percent of the aggregate principal amount of the Senior Notes repurchased plus accrued interest.

If an event of default arises from certain bankruptcy or insolvency events, all outstanding Senior Notes will become due and payable immediately without further action or notice. In addition, under the Indenture, the Senior Notes may be declared due and payable immediately by the trustee, or the holders of at least 25 percent in aggregate principal amount of the Senior Notes then outstanding, if other events of default occur, subject to certain qualifications and applicable grace periods, and are continuing under the Indenture.

Borrowings under the Senior Notes were used to repay in full and terminate commitments under the Tranche B-1 Term Loan.

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Loss on Extinguishment of Debt

In connection with the termination of the DPC and DMG credit agreements, the DPC Revolving Credit Agreement and the Tranche B-1 Term Loan, we recorded net charges of approximately $11 million, which is included in Loss on extinguishment of debt on our condensed consolidated statements of operations and consists of (i) a prepayment penalty of approximately $59 million, (ii) $2 million for the accelerated amortization of the discount on the Tranche B-1 Term Loan , (iii) $6 million for the accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Tranche B-1 Term Loan, offset by (iv) $56 million in non-cash gains for the accelerated amortization of the remaining premium related to the DPC and DMG credit agreements.

Interest Rate Swaps

Prior to executing the Credit Agreement and the issuance of the Senior Notes, we had interest rate swaps outstanding with notional amounts aggregating $1.1 billion at an average fixed rate of 2.2 percent. These swaps were scheduled to terminate in August 2016, which coincided with the termination of our previous DPC and DMG credit agreements. Subsequent to executing the Credit Agreement and issuing the Senior Notes, we amended the interest rate swaps to more closely match the terms of our existing floating rate debt. The new swaps have an aggregate notional amount of approximately $796 million at an average fixed rate of 3.15 percent with a floor of one percent. Settlements on these swaps commenced in the third quarter 2013 and run through the second quarter 2020. In lieu of paying the breakage fees related to terminating the old swaps and issuing the new swaps, the costs were incorporated into the terms of the new swaps. As a result, any cash flows related to the settlement of the new swaps will be reflected as a financing activity in our consolidated statement of cash flows.

DPC Revolving Credit Agreement

DPC, as borrower, and certain of its subsidiaries entered into a revolving credit agreement (the “DPC Revolving Credit Agreement”), dated January 16, 2013 (the “Closing Date”). Borrowings under the DPC Revolving Credit Agreement were available for ongoing working capital requirements and general corporate purposes of DPC and its subsidiaries. The DPC Revolving Credit Agreement created a 364-day senior secured revolving credit facility with commitments in principal amount of $150 million (the “DPC Revolving Credit Facility”), which was available on the closing date. DPC was required to pay a commitment fee at a rate of 0.50 percent per year on the average daily unused amount of the commitment under the DPC Revolving Credit Facility. There were no borrowings on the DPC Revolving Credit Agreement.

On April 23, 2013, we entered into the Credit Agreement, at which time the DPC Revolving Credit Agreement was terminated.

Restricted Cash

As a result of repaying and terminating these credit agreements, we no longer have any restricted cash. The following table depicts our restricted cash as of December 31, 2012:

(amounts in millions)	December 31, 2012
DPC LC facilities (1)	$220
DPC Collateral Posting Account (2)	63
DMG LC facility (1)	14
DMG Collateral Posting Account (2)	8
Corporate LC facilities (1)	27
Other (3)	3
Total restricted cash	$335

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(1) Includes cash posted to support the respective letter of credit reimbursement and collateral agreements. Please read “Letter of Credit Facilities” in our Form 10-K for further discussion.

(2) Amounts were restricted and used for future collateral posting requirements or released per the terms of the applicable credit agreement. As a result of terminating these credit agreements, all of our restricted cash was

released.

(3) Includes cash posted to support a letter of credit and collateral for the corporate card program.

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Note 13—Commitments and Contingencies
Legal Proceedings

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

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

Stockholder Litigation Relating to the Blackstone and Icahn Merger Agreements. In connection with the 2010 and 2011 terminations of the merger agreement with an affiliate of The Blackstone Group L.P. ("Blackstone") and the merger agreement with an affiliate of Icahn Enterprises L.P. ("Icahn"), respectively, numerous stockholder lawsuits and one alleged stockholder derivative lawsuit previously filed in the District Courts of Harris County, Texas, the Southern District of Texas, and the Court of Chancery of the State of Delaware were commenced. In July 2011, the Harris County District Court granted the motion of the plaintiff's lead class counsel for an award of attorney's fees and expenses. On April 4, 2013, the parties settled the matter for an immaterial amount.

Stockholder Litigation Relating to the 2011 Prepetition Restructuring. In connection with the prepetition restructuring and corporate reorganization of the DH Debtor Entities and their non-debtor affiliates in 2011 (the "2011 Prepetition Restructuring"), and specifically the DMG Transfer, a putative class action stockholder lawsuit captioned Charles Silsby v. Carl C. Icahn, et al., Case No. 12CIV2307 (the "Securities Litigation"), was filed in the United States District Court of the Southern District of New York. The lawsuit challenged certain disclosures made in connection with the DMG Transfer. We believe the plaintiff's complaint lacks merit and we continue to oppose the Securities Litigation vigorously. As a result of the filing of the voluntary petition for bankruptcy by Dynegy Inc., this lawsuit was stayed as against Dynegy Inc. and as a result of the confirmation of the Plan, the claims against Dynegy Inc. in the Securities Litigation are permanently enjoined.

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

Gas Index Pricing Litigation. We, several of our affiliates, our former joint venture affiliate and other energy companies were named as defendants in numerous lawsuits in state and federal court claiming damages resulting from alleged price manipulation and false reporting of natural gas prices to various index publications in the 2000-2002 time frame. Many of the cases have been resolved. All of the remaining cases contain similar claims that we individually, and in conjunction with other energy companies, engaged in an illegal scheme to inflate natural gas prices in four states by providing false information to natural gas index publications. In July 2011, the court granted defendants' motions for summary judgment, thereby dismissing all of plaintiffs' claims. Plaintiffs appealed the decision to the Ninth Circuit Court of Appeals which reversed the summary judgment on April 10, 2013. On August 26, 2013, we and the other defendants filed a request for review with the United States Supreme Court.

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Illinova Generating Company Arbitration. In May 2007, our subsidiary Illinova Generating Company ("IGC") received an adverse award in an arbitration brought by Ponderosa Pine Energy, LLC ("PPE"). The award required IGC to pay PPE $17 million, which IGC paid in June 2007 under protest while simultaneously seeking to vacate the award in the District Court of Dallas County, Texas. In March 2010, the Dallas District Court vacated the award, finding that one of the arbitrators had exhibited evident partiality. PPE appealed that decision to the Fifth District Court of Appeals in Dallas, Texas. Coincident with the appeal, IGC filed a claim against PPE seeking recovery of the $17 million plus interest. In September 2010, the Dallas District Court ordered PPE to deposit the $17 million principal in an interest-bearing escrow account jointly owned by IGC and PPE. On August 20, 2012, the Dallas Court of Appeals reversed the Dallas District Court and reinstated the award. IGC and the other respondents filed a petition for review with the Texas Supreme Court on December 5, 2012. As a result of the uncertainty surrounding the outcome of PPE's appeal, we did not assign any value to this potential receivable in fresh-start accounting.

Pacific Northwest Refund Proceedings. Dynegy Power Marketing, LLC ("DYPM"), along with numerous other companies that sold power in the Pacific Northwest in 2000-2001, are parties to a complaint filed in 2001 with FERC challenging bilateral contract pricing by claiming manipulation of the electricity market in California produced unreasonable prices in the Pacific Northwest. DYPM previously settled all California refund claims, but did not settle with certain complainants seeking refunds in the Pacific Northwest. In December 2011, DYPM received a Notice of Settlement from The City of Seattle ("Seattle") claiming that it paid approximately $2 million to DYPM above the mitigated market clearing price set for the California market in 2000-2001. In May 2012, Seattle made an initial settlement demand of $744 thousand plus interest. On October 1, 2012, DYPM and Seattle reached a settlement whereby DYPM agreed to pay Seattle $180 thousand (inclusive of all interest) to settle all claims between Seattle and DYPM in these proceedings. On November 29, 2012, FERC issued a letter order approving the settlement agreement. There is a risk for "ripple claims" from other sellers, but the efficacy of these claims is currently being litigated and any potential impact to DYPM from ripple claims is impossible to predict at this stage.

Other Commitments and Contingencies

In conducting our operations, we have routinely entered into long-term commodity purchase and sale commitments, as well as agreements that commit future cash flow to the lease or acquisition of assets used in our businesses. These commitments have been typically associated with commodity supply arrangements, capital projects, reservation charges associated with firm transmission, transportation, storage and leases for office space, equipment, plant sites, power generation assets and LPG vessel charters. The following describes the more significant commitments outstanding at September 30, 2013.

Dam Safety Assessment Reports. In March 2013, the EPA issued final dam safety assessment reports of the surface impoundments at our Baldwin and Hennepin facilities. The reports rate the impoundments at each facility as "poor," meaning that a deficiency is recognized for a required loading condition in accordance with applicable dam safety criteria. A poor rating also applies when further critical studies are needed to identify any potential dam safety deficiencies. The reports include recommendations for further studies, repairs and changes in operational and maintenance practices. In July 2013, in response to the final report concerning Hennepin, we notified the EPA of our intent to close the Hennepin west ash pond system. The preliminary estimated cost for closure of the west ash pond system, including post-closure monitoring, is approximately $5 million. As a result of these changes, we increased our ARO by approximately $2 million during the second quarter 2013. We plan on performing the other recommended further studies and actions at Baldwin and Hennepin, some of which are dependent on necessary permits being obtained. The nature and scope of repairs that ultimately may be needed, if any, cannot be predicted with confidence at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

Vermilion and Baldwin Groundwater. We have implemented hydrogeologic investigations for the CCR surface impoundment at our Baldwin facility and for two CCR surface impoundments at our Vermilion facility in response to a request by the Illinois EPA. Groundwater monitoring results indicate that these CCR surface impoundments impact onsite groundwater at these sites.

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

On April 2, 2012, we submitted to the Illinois EPA proposed corrective action plans for two of the CCR surface impoundments at the Vermilion facility. The proposed corrective action plans reflect the results of a hydrogeologic investigation, which indicate that the facility's old east and north CCR impoundments impact groundwater quality onsite and that such groundwater migrates offsite to the north of the property and to the adjacent Middle Fork of the Vermilion River. The proposed corrective action plans include groundwater monitoring and recommend closure of both CCR impoundments, including installation of a geosynthetic cover. In addition, we submitted an application to the Illinois EPA to establish a groundwater management zone while impacts from the facility are mitigated. The preliminary estimated cost of the recommended closure alternative for both impoundments, including post-closure care, is approximately $11 million. The Vermilion facility also has a third CCR surface impoundment, the new east impoundment that is lined and is not known to impact groundwater. Although not part of the proposed corrective action plans, if we decide to close the new east impoundment by removing its CCR contents concurrent with the recommended closure alternative for the old east and north impoundments, the associated estimated closure cost would add an additional $2 million to the above estimate.

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In December 2012, the Illinois EPA provided written notice that it may pursue legal action with respect to each matter through referral to the Illinois Office of the Attorney General. In accordance with work plans approved by the Illinois EPA, we have initiated a six month geotechnical study at Vermilion and have begun a twelve month geotechnical/hydraulic/hydrogeologic study needed to analyze corrective action alternatives at Baldwin. At this time we cannot reasonably estimate the costs of resolving these matters, but resolution of these matters may cause us to incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows.

Cooling Water Intake Permits. The cooling water intake structures at several of our power generation facilities are regulated under Section 316(b) of the Clean Water Act. This provision generally provides that standards set for power generation facilities require that the location, design, construction and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact. These standards are developed and implemented for power generating facilities through the individual NPDES (or SPDES) permits on a case-by-case basis.

The environmental groups that participate in our NPDES permit proceedings generally argue that only closed cycle cooling meets the BTA requirement. The issuance and renewal of the NPDES permit for one of our power generation facilities (Moss Landing) was challenged on this basis. The Moss Landing NPDES permit, which was issued in 2000, does not require closed cycle cooling and was challenged by a local environmental group. In August 2011, the Supreme Court of California affirmed the appellate court's decision upholding the permit.

Other future NPDES proceedings could have a material effect on our financial condition, results of operations and cash flows; however, given the numerous variables and factors involved in calculating the potential costs associated with installing a closed cycle cooling system, any decision to install such a system at any of our facilities would be made on a case-by-case basis considering all relevant factors at such time. If capital expenditures related to cooling water systems become great enough to render the operation of the plant uneconomical, we could, at our option, and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate that facility and forego the capital expenditures.

In September 2012, the Illinois EPA issued a renewal NPDES permit for the Havana Power Station. In October 2012, environmental interest groups filed a petition for review with the IPCB challenging the permit. The petitioners allege that the permit does not adequately address the discharge of wastewaters associated with newly installed air pollution control equipment (i.e., a spray dryer absorber and activated carbon injection system to reduce SO_2 and mercury air emissions) at Havana. The permit remains in effect during the appeal. The petitioners subsequently filed a separate petition with the IPCB to reopen the Havana NPDES permit to include limitations on the affected wastewater discharges. In September 2013, the IPCB dismissed the petition to reopen the permit. The permit appeal remains pending. We dispute the allegations in the permit appeal and will defend the permit vigorously. The outcome of this

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

filed an appeal of the remand order in the D.C. Circuit. On December 18, 2012, the D.C. Circuit issued an order denying the appeal of the generator group and affirming FERC's orders on remand.

On November 18, 2011, PG&E filed with the CPUC, seeking authorization to begin charging generators station power charges, and to assess such charges retroactively, which the Company and other generators have challenged. Dynegy Morro Bay, LLC, Dynegy Moss Landing, LLC and Dynegy Oakland, LLC filed a protest with the CPUC objecting to PG&E's filing. That protest is still pending. The CPUC Commissioners were scheduled to vote on a draft resolution that rejected the arguments in our protest and approved PG&E's proposed station power charges, including retroactive implementation of such charges, on October 15, 2012. However, the draft resolution was withdrawn from the Commission's calendar and has not yet been rescheduled for a vote. We believe we have established an appropriate accrual.

SCE Termination. In May 2012, SCE notified Dynegy Morro Bay, LLC ("DMB") and Dynegy Moss Landing, LLC ("DML"), that it was terminating certain energy and capacity contracts with those entities. The terminations were disputed by Dynegy in parallel arbitration and federal court litigation. On October 10, 2013, Dynegy and SCE agreed to resolve the dispute by entering into two new transactions between SCE and DML. Under the first transaction, SCE agreed to purchase energy and capacity from Units 6 & 7 of the Moss Landing Energy Facility for 2014 and 2015 and, under the second transaction, to purchase energy and capacity from Units 6 & 7 for 2016. The 2016 transaction is conditioned on approval by the CPUC, which both SCE and Dynegy have agreed to seek in good faith and use commercially reasonable efforts to obtain. The pending arbitration and federal court litigation have been dismissed as a result of the new transactions.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. In June 2013, we amended our maintenance agreements. The term of the agreements will be determined by the maintenance cycles of the respective facility. We currently estimate these agreements will be in effect for a period of 15 or more years. Either party can terminate the agreements based on certain events as specified in the contracts. As of September 30, 2013, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $150 million and $219 million in the event all contracts are terminated by us or the counterparty, respectively.

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, 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.

Indemnifications

We entered into indemnifications regarding environmental, tax, employee and other representations when completing asset sales such as, but not limited to, Calcasieu and Heard County power generating facilities, the sale of our midstream business ("DMSLP"), the sale of Illinois Power Company and the sale of assets to LS Power. DPC remains the sole entity liable for indemnification claims with respect to Calcasieu and Heard County. DYPM remains liable for indemnification claims with respect to DMSLP. Illinova Corporation remains liable for any indemnification claims resulting from the Illinois Power Company sale. DPC, DMG and DYPM remain jointly and severally liable for any indemnification claims for the LS Power asset sales. As of September 30, 2013, no claims have been made against us and we have not recorded a liability for these indemnities.

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Guarantees

Black Mountain Guarantee. Through one of our subsidiaries, we hold a 50 percent ownership interest in Black Mountain (Nevada Cogeneration) ("Black Mountain"), in which our partner is a Chevron subsidiary. Black Mountain owns the Black Mountain power generation facility and has a power purchase agreement with a third party that extends through April 2023. In connection with the power purchase agreement, pursuant to which Black Mountain receives payments which decrease in amount over time, we agreed to guarantee 50 percent of certain payments that may be due to the power purchaser under a mechanism designed to protect it from early termination of the agreement. At September 30, 2013, if an event of default due to early termination had occurred under the terms of the mortgage on the facility entered into in connection with the power purchase agreement, we could have been required to pay the power purchaser approximately $52 million under the guarantee. No amount has been accrued related to this guarantee as we consider the likelihood of a default to be remote.

Other Minimum Commitments

We are party to two charter agreements related to VLGCs previously utilized in our former global liquids business. The primary term of one charter expired at the end of September 2013, but has been extended for a period of one year, at the sole option of the counterparty. The primary term of the second charter is through September 2014. Both of these VLGCs have been sub-chartered to a wholly-owned subsidiary of Transammonia Inc. on terms that are identical to the terms of the original charter agreements. The aggregate minimum base commitments of the charter party agreement is approximately $3 million and $11 million for the remainder of 2013 and 2014, respectively. To date, the subsidiary of Transammonia Inc. has complied with the terms of the sub-charter agreement.

Note 14—Related Party Transactions

The following table summarizes the cash received (paid) related to various agreements with Dynegy Inc., as discussed below.

(amounts in millions)	Successor Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Service Agreements	$—	$2	$(2)	$13
EMA Agreements	—	—	—	1
Total	$—	$2	$(2)	$14

The following table summarizes the Accounts receivable, affiliates, and Accounts payable, affiliates, on our unaudited condensed consolidated balance sheets related to various agreements with Dynegy Inc., as discussed below.

(amounts in millions)	September 30, 2013 Accounts Receivable, Affiliates	Accounts Payable, Affiliates	December 31, 2012 Accounts Receivable, Affiliates	Accounts Payable, Affiliates
Service Agreements	$—	$1	$1	$1
Total	$—	$1	$1	$1

Service Agreements. Legacy Dynegy and certain of our subsidiaries (collectively, the "Providers") provided certain services (the "Services") to DCIH and certain of its subsidiaries, and certain of our subsidiaries (collectively, the "Recipients"). Additionally, we provide certain services to the DNE Debtor Entities. Service Agreements between Legacy Dynegy and the Recipients govern the terms under which such Services are provided.

As a result of the Merger, transactions between DH and Legacy Dynegy executed under the Service Agreements subsequent to September 30, 2012, are no longer considered related party transactions because they eliminate in consolidation.

On October 1, 2012, Dynegy deconsolidated the DNE Debtor Entities. Please read Note 1—Organization and Operations—Chapter 11 Filing and Emergence from Bankruptcy in our Form 10-K for further discussion. Our unaudited condensed consolidated statements of operations include zero and $3 million of power purchased from our unconsolidated affiliate, which is reflected in Revenues for the three and nine months ended September 30, 2013, respectively.

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Energy Management Agreements. Certain of our subsidiaries have entered into an Energy Management Agency Services Agreement (an "EMA") with DMG. Pursuant to the EMA, our subsidiaries will provide power management services to other subsidiaries, consisting of marketing power and capacity, capturing pricing arbitrage, scheduling dispatch of power, communicating with the applicable ISOs or RTOs, purchasing replacement power, and reconciling and settling ISO or RTO invoices. In addition, certain of our subsidiaries will provide fuel management services, consisting of procuring the requisite quantities of fuel and emissions credits, assisting with transportation, scheduling delivery of fuel, assisting with development and implementation of fuel procurement strategies, marketing and selling excess fuel and assisting with the evaluation of present and long-term fuel purchase and transportation options. Our subsidiaries will also assist other subsidiaries with risk management by entering into one or more risk management transactions, the purpose of which is to set the price or value of any commodity or to mitigate or offset any change in the price or value of any commodity. Our subsidiaries may from time to time provide other services as the parties may agree. As a result of the DMG Acquisition, transactions executed under the EMA are not considered related party transactions subsequent to June 5, 2012 because they eliminate in consolidation. Our unaudited condensed consolidated statements of operations include $198 million of power purchased from affiliates, which is reflected in Revenues, and $79 million of coal sold to affiliates, which is reflected in Costs of sales, for the nine months ended September 30, 2012, respectively. This affiliate activity is presented net of third party activity within Revenue and Cost of sales. Also, please read Note 6—Risk Management Activities, Derivatives and Financial Instruments for derivative balances with affiliates.

DMG Transfer and Undertaking Agreement. During the nine months ended September 30, 2012, we recognized $24 million in interest income related to the Undertaking Agreement which is included in Other income and expense, net, in our unaudited condensed consolidated statements of operations. We did not recognize any interest income subsequent to March 31, 2012 as we impaired the value of the Undertaking as of March 31, 2012. In addition, we received payments of $48 million from Legacy Dynegy during the nine months ended September 30, 2012 related to the termination of the Undertaking Agreement. The Undertaking Agreement was terminated on June 5, 2012 in connection with the execution of the Settlement Agreement.

Note payable, affiliates. On August 5, 2011, Coal Holdco made a loan to DH of $10 million with a maturity of three years and an interest rate of 9.25 percent per annum. The Note payable, affiliate was written off during the first quarter 2012 as it was determined that no claim would be filed related to the note.

Note 15—Income Taxes

Effective Tax Rate. 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. Dynegy Inc.'s income taxes included in continuing operations were as follows:

(amounts in millions, except rates)	Successor Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Income tax benefit	$20	$20	$2	$9
Effective tax rate	NM	7 %	5 %	1 %

Our overall tax rate is expected to be approximately zero percent as a result of the change in our valuation allowance for each period. However, for the three and nine months ended September 30, 2013, our overall effective tax rate on continuing operations was affected by the recognition of a tax benefit from a change in our valuation allowance in continuing operations that occurred as a result of offsetting tax expense recognized in income from discontinued operations and OCI. This was a result of the plan amendments and resulting remeasurements associated with certain of our pension and other post-employment benefit plans. In addition, during the three and nine months ended September 30, 2013, we recorded tax expense for an uncertain tax position of $7 million pursuant to a proposed state assessment that we believe no longer meets the more likely than not criteria for recognizing a tax benefit.

For the three months ended September 30, 2012, our overall effective tax rate on continuing operations of five percent was different than the statutory tax rate of 35 percent primarily due to the impact of state taxes. For the nine months ended September 30, 2012, our overall effective tax rate on continuing operations of one percent was different than the statutory tax rate of 35 percent primarily due to a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes.

Note 16—Pension and Other Post-Employment Benefit Plans

We sponsor and administer defined benefit plans and defined contribution plans for the benefit of our employees and also provide other post-employment benefits to retirees who meet age and service requirements which are more fully described in Note 24—Employee Compensation, Savings and Pension Plans in our Form 10-K.

As a result of the DMG Transfer on September 1, 2011, we and our subsidiaries were no longer the primary participant in certain defined benefit pension and other post-employment benefit plans sponsored by Legacy Dynegy; therefore, we began accounting for our participation in these plans as multi-employer plans. Additionally, we completed the DMG Acquisition on June 5, 2012, and we were once again the primary participant in certain defined benefit pension and other post-employment benefit plans; therefore, the costs related to these plans were only included within net periodic benefit costs subsequent to June 5, 2012.

During the second quarter 2013, we recognized a curtailment gain of $7 million in connection with the termination of a majority of the Danskammer employees and the sale of our Roseton facility. As a result of the curtailment, the plan was remeasured. On September 20, 2013, we reached an agreement with the union (“IBEW Local 51”) that resulted in amendments to certain pension and other post-employment benefit plans. As a result of these amendments, we remeasured our benefit obligations and the funded status of the affected plans. As a result of the remeasurements, we recorded a pre-tax gain of approximately $71 million ($46 million, net of tax) through accumulated other comprehensive income (loss) during the third quarter 2013.

Obligations and Funded Status. The following tables summarize information regarding our obligations and funded status of plans in which we, or one of our subsidiaries, sponsor. In the tables below, the projected benefit obligations and values of plan assets were only updated for those plans affected by the plan amendments or curtailment. For the plans that were not affected by the plan amendments or curtailment, these amounts are based on the measurements performed as of December 31, 2012.

	Pension Benefits		Other Benefits	
(amounts in millions)	September 30, 2013	December 31, 2012	September 30, 2013	December 31, 2012
Projected benefit obligation	$ 307	$ 337	$ 27	$ 55
Estimated value of plan assets	293	277	—	—
Funded status reflected in balance sheet	$ (14)	$ (60)	$ (27)	$ (55)

Amounts recognized in the consolidated balance sheets consist of:

	Pension Benefits		Other Benefits	
(amounts in millions)	September 30, 2013	December 31, 2012	September 30, 2013	December 31, 2012
Current liabilities	$ —	$ —	$ (1)	$ (2)
Non-current liabilities	(14)	(60)	(26)	(53)
Net amount recognized	$ (14)	$ (60)	$ (27)	$ (55)

Pre-tax amounts recognized in AOCI consist of:

	Pension Benefits		Other Benefits	
(amounts in millions)	September 30, 2013	December 31, 2012	September 30, 2013	December 31, 2012
Prior service credit	$ (14)	$ (7)	$ (27)	$ —
Actuarial gain	(31)	(4)	(3)	—
Net gain recognized	$ (45)	$ (11)	$ (30)	$ —

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

	Pension Benefits			
	Successor		Predecessor	
(amounts in millions)	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Service cost benefits earned during period	$2	$7	$2	$3
Interest cost on projected benefit obligation	3	9	3	4
Expected return on plan assets	(5)	(14)	(4)	(5)
Recognized net actuarial loss	—	—	2	2
Curtailment gain (1)	—	(7)	—	—
Total net periodic benefit cost (gain)	$—	$(5)	$3	$4

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

	Other Benefits			
	Successor		Predecessor	
(amounts in millions)	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Service cost benefits earned during period	$—	$1	$1	$2
Interest cost on projected benefit obligation	1	2	—	1
Total net periodic benefit cost	$1	$3	$1	$3

Assumptions. The following assumptions were used to determine the benefit obligations for the plans affected by the plan amendments:

	Pension Benefits		Other Benefits	
	September 30, 2013	December 31, 2012	September 30, 2013	December 31, 2012
Discount rate	4.90 %	3.98 %	4.75 %	4.08 %
Rate of compensation increase	3.50 %	3.50 %	N/A	N/A
Interest crediting rate	3.65 %	2.48 %	N/A	N/A
Current health care cost trend rate	N/A	N/A	7.75 %	7.75 %
Ultimate health care cost trend rate	N/A	N/A	4.50 %	4.50 %
Year of ultimate trend rate	N/A	N/A	2020	2020

Contributions. We are not required to make contributions to our pension plans and other post-employment benefit plans during 2013; however, during the nine months ended September 30, 2013, we made $7 million in voluntary contributions to our pension plans and no contributions to our other post-employment benefit plans.

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Note 17—Earnings (Loss) Per Share
The reconciliation of basic earnings (loss) per share from continuing operations to diluted earnings (loss) per share from continuing operations of our common stock outstanding during the period is shown in the following table. Basic earnings (loss) per share represents the amount of earnings or losses for the period available to each share of our common stock outstanding during the period. Diluted earnings (loss) per share represents the amount of earnings or losses for the period available to each share of our common stock outstanding during the period plus each share that would have been outstanding assuming the issuance of common shares for all dilutive potential common shares outstanding during the period. Please read Note 23—Capital Stock in our Form 10-K for further discussion.
Prior to the Merger, DH was organized as a limited liability company and the capital structure of DH did not change until September 30, 2012. Although Legacy Dynegy's shares were publicly traded, DH did not have any publicly traded shares during the Predecessor periods; therefore, no loss per share is presented for the three and nine months ended September 30, 2012.

(in millions, except per share amounts)	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Income (loss) from continuing operations for basic and diluted earnings (loss) per share	$24	$(268)
Basic weighted-average shares	100	100
Effect of dilutive securities—stock options and restricted stock units	—	—
Diluted weighted-average shares	100	100
Earnings (loss) per share from continuing operations:		
Basic	$0.24	$(2.68)
Diluted (1)	$0.24	$(2.68)

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(1) Entities with a net loss from continuing operations are prohibited from including potential common shares in the computation of diluted per share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the nine months ended September 30, 2013.

Note 18—Segment Information
We report the results of our operations in two segments: (i) Coal and (ii) Gas. In connection with our emergence from bankruptcy, we deconsolidated the DNE Debtor Entities and we began accounting for our investment in the DNE Debtor Entities using the cost method. Accordingly, we have reclassified DNE's operating results as discontinued operations in the consolidated financial statements for all periods presented. Subsequent to our emergence from bankruptcy, management does not consider general and administrative expense when evaluating the performance of our Coal and Gas segments, but instead evaluates general and administrative expense on an enterprise-wide basis. Accordingly, we recast our segments to present general and administrative expense in Other and Eliminations for all periods presented.
On September 1, 2011, we completed the DMG Transfer. Additionally, on June 5, 2012, we reacquired the Coal segment through the DMG Acquisition; therefore, the results of our Coal segment are only included in our consolidated results subsequent to June 5, 2012. Please read Note 3—Acquisitions—DMG Acquisition for further discussion.
Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the three and nine months ended September 30, 2013 and 2012 is presented below:

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

	Successor			
(amounts in millions)	Coal	Gas	Other and Eliminations	Total
Domestic:				
Unaffiliated revenues	$138	$308	$—	$446
Intercompany revenues	1	(1)	—	—
Total revenues	$139	$307	$—	$446
Depreciation expense	$(13)	$(39)	$(1)	$(53)
General and administrative expense	—	—	(22)	(22)
Operating income (loss)	$(34)	$74	$(25)	$15
Bankruptcy reorganization items, net	—	—	1	1
Interest expense				(26)
Other items, net	—	—	14	14
Income from continuing operations before income taxes				4
Income tax benefit				20
Income from continuing operations				24
Loss from discontinued operations, net of tax				(2)
Net income				$22
Identifiable assets (domestic)	$1,196	$2,347	$607	$4,150
Capital expenditures	$(7)	$(4)	$(1)	$(12)

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DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2013 and 2012

Segment Data as of and for the Three Months Ended September 30, 2012

	Predecessor			
(amounts in millions)	Coal	Gas	Other and Eliminations	Total
Domestic:				
Unaffiliated revenues	$126	$317	$—	$443
Total revenues	$126	$317	$—	$443
Depreciation expense	$(9)	$(35)	$(1)	$(45)
General and administrative expense	—	—	(29)	(29)
Operating income (loss)	$(46)	$66	$(31)	$(11)
Bankruptcy reorganization items, net	—	—	18	18
Interest expense				(48)
Loss from continuing operations before income taxes				(41)
Income tax benefit				2
Loss from continuing operations				(39)
Loss from discontinued operations, net of tax				(2)
Net loss				$(41)
Identifiable assets (domestic)	$1,176	$4,378	$417	$5,971
Capital expenditures	$(22)	$(3)	$(1)	$(26)

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DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended September 30, 2013 and 2012

Segment Data as of and for the Nine Months Ended September 30, 2013

	Successor			
(amounts in millions)	Coal	Gas	Other and Eliminations	Total
Domestic:				
Unaffiliated revenues	$339	$726	$—	$1,065
Intercompany revenues	2	(2)	—	—
Total revenues	$341	$724	$—	$1,065
Depreciation expense	$(36)	$(118)	$(2)	$(156)
General and administrative expense	—	—	(69)	(69)
Operating income (loss)	$(163)	$30	$(78)	$(211)
Bankruptcy reorganization items, net	—	—	(2)	(2)
Interest expense				(71)
Loss on extinguishment of debt				(11)
Other items, net	—	—	7	7
Loss from continuing operations before income taxes				(288)
Income tax benefit				20
Loss from continuing operations				(268)
Income from discontinued operations, net of tax				3
Net loss				$(265)
Identifiable assets (domestic)	$1,196	$2,347	$607	$4,150
Capital expenditures	$(38)	$(27)	$(2)	$(67)

DYNEGY INC.
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Segment Data as of and for the Nine Months Ended September 30, 2012

	Predecessor			
(amounts in millions)	Coal	Gas	Other and Eliminations	Total
Domestic:				
Unaffiliated revenues	$166	$815	$—	$981
Total revenues	$166	$815	$—	$981
Depreciation expense	$(13)	$(91)	$(6)	$(110)
General and administrative expense	—	—	(66)	(66)
Operating income (loss)	$(63)	$128	$(72)	$(7)
Bankruptcy reorganization items, net	—	—	147	147
Interest expense				(120)
Impairment of Undertaking receivable, affiliate	—	—	(832)	(832)
Other items, net	5	2	24	31
Loss from continuing operations before income taxes				(781)
Income tax benefit				9
Loss from continuing operations				(772)
Loss from discontinued operations, net of tax				(420)
Net loss				$(1,192)
Identifiable assets (domestic)	$1,176	$4,378	$417	$5,971
Capital expenditures	$(33)	$(23)	$(7)	$(63)

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DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended September 30, 2013 and 2012

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

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

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as two separate segments in our unaudited condensed consolidated financial statements: (i) Coal and (ii) Gas. In connection with our emergence from bankruptcy on the Plan Effective Date, we deconsolidated the DNE Debtor Entities, which constituted our previously reported DNE segment, and began accounting for our investment in the DNE Debtor Entities using the cost method. Accordingly, we have reclassified the results of the previously reported DNE segment as discontinued operations in our consolidated financial statements for all periods presented.

Refinancing of Debt Obligations

During the nine months ended September 30, 2013, we refinanced existing indebtedness.

New Credit Agreement. On April 23, 2013, Dynegy entered into $1.775 billion in new credit facilities including $1.3 billion in new senior, secured term loans and a $475 million corporate revolver. The proceeds of the term loans were used, together with cash on hand, to repay the former DMG and DPC credit agreements and fund related transaction costs. Please read Note 12—Debt for further discussion.

Senior Notes. On May 20, 2013, Dynegy and its Subsidiary Guarantors entered into an Indenture pursuant to which Dynegy issued $500 million in aggregate principal amount of Senior Notes. Borrowings under the Senior Notes were used to repay in full and terminate commitments under a portion of the senior, secured term loans. Please read Note 12—Debt for further discussion.

AER Transaction Agreement

On March 14, 2013, IPH entered into the AER Transaction Agreement, whereby IPH will acquire AER (or, following a pre-closing reorganization contemplated by Ameren, a successor thereto) and its subsidiaries. There will be no cash consideration or stock issued as part of the purchase price. Genco's debt will remain outstanding. The transaction is subject to certain closing conditions and the receipt of regulatory approvals. On October 11, 2013, AER and IPH received FERC Approval and in August 2013, they received FCC Approval. On June 6, 2013, the IPCB rejected, on procedural grounds, AER's and IPH's motion to transfer variance relief from Illinois' Multi-Pollutant Standard. The IPCB indicated that IPH may file a request for variance relief on its own behalf. IPH and AER are pursuing such relief, and on July 22, 2013 IPH and certain co-petitioners filed their request for variance relief and a hearing was held on September 17, 2013. The IPCB is expected to make its decision on that request on or before November 21, 2013. Pending the receipt of variance relief, the closing is expected to occur in December 2013. Please read Note 3—Acquisitions—AER Transaction Agreement for further discussion.

Collective Bargaining Agreement - IBEW Local 51

In March 2013, we began negotiations with the union ("IBEW Local 51") regarding its collective bargaining agreement, which expired, following an extension, on July 8, 2013. This agreement covers approximately 400 represented employees at our four Coal plants located in Illinois. On August 1, 2013, we and IBEW Local 51 reached a tentative agreement on a new collective bargaining agreement. On September 20, 2013, following a voting process conducted by IBEW Local 51, the tentative agreement was successfully ratified by union employees and resulted in amendments to certain pension and other post-employment benefit plans. As a result of these amendments and resulting remeasurements, we significantly reduced our benefit obligations under the affected plans. This new agreement, which expires on June 30, 2017, further aligns our near-term and long-term strategic priorities. Please read Note

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

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LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, fixed capacity payments and contractual obligations, capital expenditures (including required environmental expenditures) and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated margin and collateral requirements, facility maintenance costs and other costs such as payroll.

Our primary sources of liquidity are cash flows from operations, cash on hand and amounts available under the revolver.

On April 23, 2013, Dynegy entered into the Credit Agreement, which consists of (i) a $500 million Tranche B-1 Term Loan, (ii) an $800 million Tranche B-2 Term Loan and (iii) a $475 million Revolving Facility. Borrowings under the Credit Agreement, together with a portion of our cash on hand, were used to repay in full and terminate commitments under: (i) the DPC Credit Agreement and DMG Credit Agreement, (ii) the DPC Revolving Credit Agreement, (iii) the DPC Letter of Credit Reimbursement and Collateral Agreement, (iv) the DMG Letter of Credit Reimbursement and Collateral Agreement, (v) the Dynegy Letter of Credit Reimbursement and Collateral Agreement and (vi) the Dynegy CS Letter of Credit Agreement. As a result of repaying these credit agreements, we no longer have any restricted cash.

On May 20, 2013, Dynegy and its Subsidiary Guarantors entered into an Indenture pursuant to which Dynegy issued $500 million in aggregate principal amount of Senior Notes. Borrowings under the Senior Notes were used to repay in full and terminate commitments under the Tranche B-1 Term Loan (as discussed above). Please read Note 12—Debt for further discussion.

These financings improved our capital structure efficiency and flexibility, increased liquidity and reduced administrative costs.

Current Liquidity. The following tables summarize our liquidity position at November 4, 2013 and September 30, 2013.

(amounts in millions)	November 4, 2013	September 30, 2013
Revolver capacity	$475	$475
Less: Outstanding letters of credit	(181)	(183)
Revolver availability	294	292
Cash and cash equivalents	597	589
Total available liquidity	$891	$881

Operating Activities

Historical Operating Cash Flows. Our cash flow provided by operations totaled $132 million for the nine months ended September 30, 2013. During the period, we had positive Adjusted EBITDA (as described below in Results of Operations—EBITDA and Adjusted EBITDA) of $164 million and $42 million in positive changes in working capital, primarily including $36 million of decreased collateral postings primarily for the return of collateral. This was offset by $55 million in interest payments and $19 million in payments for bankruptcy reorganization, acquisition and integration and other expenses.

Our cash flow used in operations totaled $37 million for the nine months ended September 30, 2012. During the period, we had (i) positive Adjusted EBITDA (as described below in Results of Operations—EBITDA and Adjusted EBITDA) of $90 million, (ii) $16 million due to interest payments received from Legacy Dynegy and (iii) $7 million related to the receipt of a tax refund. This was offset by (i) negative Adjusted EBITDA of $22 million related to discontinued operations, (ii) $99 million in interest payments and (iii) $29 million in negative changes in working capital, net of $36 million of increased collateral postings to satisfy our counterparty collateral demands.

Future Operating Cash Flows. Our future operating cash flows will vary based on a number of factors, many of which are beyond our control, including the price of power, the prices of natural gas, coal, and fuel oil and their correlation to power prices, collateral requirements, the value of capacity and ancillary services, the run time of our generating facilities, the effectiveness of our commercial strategy, legal, environmental and regulatory requirements, and our ability to achieve the cost savings contemplated in our PRIDE improvement programs.

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Collateral Postings. We use a significant portion of our capital resources in the form of cash and letters of credit to satisfy counterparty collateral demands. The following table summarizes our collateral postings to third parties at November 4, 2013, September 30, 2013 and December 31, 2012:

(amounts in millions)	November 4, 2013	September 30, 2013	December 31, 2012
Cash (1)	$27	$25	$64
Letters of credit	181	183	252
Total	$208	$208	$316

(1) Includes Broker margin account on our unaudited condensed consolidated balance sheets as well as other collateral postings included in Prepayments and other current assets on our unaudited condensed consolidated balance sheets. As of September 30, 2013 and December 31, 2012, $8 million of cash posted as collateral was netted against Liabilities from risk management activities on our unaudited condensed consolidated balance sheets.

In addition to cash and letters of credit posted as collateral, we have granted additional permitted first priority liens on assets already subject to first priority liens under our former and new credit agreements. The additional liens were granted as collateral under certain of our derivative agreements in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to the counterparties under such agreements.

Collateral postings decreased from December 31, 2012 to September 30, 2013 primarily due to new first lien contracts related to our fuel purchases being executed with counterparties, amending our contractual service agreements, a reduction in collateral supporting our DNE operations and overall changes in our commercial activity. Collateral postings were relatively consistent from September 30, 2013 to November 4, 2013.

The fair value of our derivatives collateralized by first priority liens included liabilities of $112 million, $104 million and $100 million at November 4, 2013, September 30, 2013 and December 31, 2012, respectively.

We expect counterparties' future collateral demands to continue to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their views of our creditworthiness. Our ability to use forward economic hedging instruments could be limited due to the potential collateral requirements of such instruments.

Investing Activities

Capital Expenditures. We had capital expenditures of approximately $67 million and $63 million during the nine months ended September 30, 2013 and 2012, respectively. Our capital spending by reportable segment was as follows:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012
Coal (1)	$38	$33
Gas	27	23
Other and eliminations	2	7
Total	$67	$63

(1) On June 5, 2012, we completed the DMG Acquisition; therefore, capital expenditures were only included subsequent to June 5, 2012. For the nine months ended September 30, 2012, including the periods that Coal was not included in our consolidated financial statements, Coal capital expenditures were $75 million.

Other Investing Activities. During the nine months ended September 30, 2013, there was a $335 million cash inflow related to restricted cash balances due to the release of cash collateral associated with the DPC LC and DMG LC facilities. A portion of these proceeds were used to repay in full and terminate commitments under the DMG and DPC credit agreements as further discussed below. As a result of repaying these credit agreements, all of our restricted cash was released.

In connection with the DMG Acquisition on June 5, 2012, we acquired $256 million in cash and received $16 million related to the Undertaking during the nine months ended September 30, 2012. There was an $88 million cash inflow related to restricted cash balances associated with the DPC LC facilities and DPC Credit Agreement during the nine months ended September 30, 2012. During the first quarter 2012, we requested the release of unused cash collateral related to the DPC LC facilities.

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Financing Activities

Historical Cash Flow from Financing Activities. Cash flow used in financing activities totaled $162 million for the nine months ended September 30, 2013 due to $1.913 billion in repayments of borrowings in full on the DMG and DPC credit agreements and the Tranche B-1 Term Loan, including $59 million in prepayment penalties associated with the early termination of the DMG and DPC credit agreements, and $2 million in principal payments of borrowings on the Tranche B-2 Term Loan, offset by $1.753 billion in proceeds from borrowings on the Credit Agreement and Senior Notes, net of financing costs.

Cash flow provided by financing activities totaled $16 million for the nine months ended September 30, 2012 due to $27 million in connection with the recapitalization of Legacy Dynegy, offset by $11 million in repayments of borrowings on the former DMG and DPC credit agreements.

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 connected to the financing include the violation of covenants (including, 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 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.

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

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

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

Our revolver usage was 39 percent of the aggregate revolver commitment due to outstanding letters of credit; therefore, we were required to test the covenant. Based on the calculation outlined in the Credit Agreement, we are in compliance at September 30, 2013.

Please read Note 12—Debt for further discussion.

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Credit Ratings

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

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

Update of Selected Contractual Obligations

We have incurred various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities.

The following table updates selected contractual obligations of the Company and its consolidated subsidiaries as of September 30, 2013 from our Form 10-K disclosure for changes that occurred during 2013. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Expiration by Period				
	Total	Remainder of 2013	2014-2015	2016-2017	2018 and Beyond
Long-term debt (including current portion)	$ 1,298	$ 2	$ 16	$ 16	$ 1,264
Interest payments on debt	$ 623	$ 20	$ 169	$ 160	$ 274
Contractual service agreements (1)	$ 124	$ 5	$ 63	$ 56	$ —

(1) The table above includes projected payments through 2017 assuming the contracts remain in full force and effect; however, we currently estimate these agreements will be in effect for a period of 15 or more years. Our minimum obligation related to these agreements is limited to the termination payments.

Long-Term Debt (Including Current Portion). Long-term debt includes amounts related to the Senior Notes and the Credit Agreement. Please read Note 12—Debt for further discussion.

Interest Payments on Debt. Interest payments on debt represent estimated periodic interest payment obligations associated with the Senior Notes and the Credit Agreement. Amounts include the impact of interest rate swap agreements. Please read Note 12—Debt for further discussion.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. In June 2013, we amended our maintenance agreements. The amendments substantially reduced collateral postings, restructured and reduced maintenance costs, extended the term of the agreements, decreased our risk from a catastrophic turbine failure and included technology upgrades for our equipment. We currently estimate these agreements will be in effect for a period of 15 or more years. The table above includes our current estimate of payments under the contracts through 2017 based on anticipated timing of outages and are subject to change as outage dates move. As of September 30, 2013, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $150 million and $219 million in the event all contracts are terminated by us or the counterparty, respectively. Please read Note 13—Commitments and Contingencies for further discussion.

Please read "Disclosure of Contractual Obligations and Contingent Financial Commitments" in our Form 10-K for further discussion. Please read "Uncertainty of Forward-Looking Statements and Information" for additional factors that could impact our future operating results and financial condition.

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RESULTS OF OPERATIONS

Overview

In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three and nine months ended September 30, 2013 and 2012. 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 two separate segments in our consolidated financial statements: (i) Coal and (ii) Gas. In connection with our emergence from bankruptcy, we deconsolidated the DNE Debtor Entities, which constituted our previously reported DNE segment, and began accounting for our investment in the DNE Debtor Entities using the cost method. Accordingly, we have reclassified the results of the previously reported DNE segment as discontinued operations in the consolidated financial statements for all periods presented. Subsequent to our emergence from bankruptcy, management does not consider general and administrative expense when evaluating the performance of our Coal and Gas segments, but instead evaluates general and administrative expense on an enterprise-wide basis. Accordingly, we have recast our segments to present general and administrative expense in Other and Eliminations for all periods presented.

We applied fresh-start accounting as of the Plan Effective Date. Fresh-start accounting required us to allocate the reorganization value to our assets and liabilities in a manner similar to the acquisition method of accounting for business combinations. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K for further discussion.

On September 1, 2011, we completed the DMG Transfer. Additionally, on June 5, 2012, we reacquired the Coal segment through the DMG Acquisition. Therefore, the results of our Coal segment are only included in our consolidated results subsequent to June 5, 2012.

Non-GAAP Performance Measures. In analyzing and planning for our business, we supplement our use of GAAP financial measures with non-GAAP financial measures, including EBITDA and Adjusted EBITDA. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed with our GAAP results and the accompanying reconciliations to corresponding GAAP financial measures included in the tables below, may provide a more complete understanding of factors and trends affecting our business. These non-GAAP financial measures should not be relied upon to the exclusion of GAAP financial measures and are by definition an incomplete understanding of Dynegy, and must be considered in conjunction with GAAP measures. 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 economic hedges related to our generation portfolio, as well as interest rate swaps and warrants, (iii) the impact of impairment charges and certain other costs such as those associated with the acquisition of AER, internal reorganization and bankruptcy proceedings, (iv) amortization of intangible assets and liabilities, (v) income or loss associated with discontinued operations and (vi) income or expense on up front premiums received or paid for financial options in periods other than the strike periods. Enterprise-wide Adjusted EBITDA includes the Adjusted EBITDA for Legacy Dynegy for the periods prior to the Merger.

Enterprise-wide Adjusted EBITDA is meant to reflect the operating performance of our entire power generation fleet for the period presented; consequently, it excludes the impact of mark-to-market accounting, impairment charges, gains and losses on sales of assets and other items that could be considered "non-operating" or "non-core" in nature. Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers and evaluate overall financial performance, we believe they provide useful information for our investors. In addition, many analysts, fund managers, and other stakeholders that communicate with us typically request our financial results in an EBITDA and Adjusted

EBITDA format presented on an enterprise-wide basis.

As prescribed by the SEC, when Adjusted EBITDA is discussed in reference to performance on a consolidated basis, the most directly comparable GAAP financial measure to EBITDA and Adjusted EBITDA is Net income (loss). Management does not analyze interest expense and income taxes on a segment level; therefore, the most directly comparable GAAP financial measure to Adjusted EBITDA when performance is discussed on a segment level is Operating income (loss).

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Significant Items

Our results of operations are impacted by several significant items. In the discussion below, we have included the variances associated with these significant items in tables with the following descriptions:

- DMG Transfer—The amounts in the tables add back the results of our Coal segment for the period of time that our Coal segment was not included in the consolidated results due to the DMG Transfer. For the nine months ended September 30, 2012, this amount includes the results of operations related to the Coal segment for the period of January 1 through June 5, 2012.
- DMG Acquisition—The DMG Acquisition was accounted for using the acquisition method. Therefore, the acquired assets and liabilities were recorded at their estimated fair values as of the acquisition date. As a result, our results for the three and nine months ended September 30, 2012 include the amortization of intangible assets and liabilities that were established at the acquisition date. In addition, the property, plant and equipment associated with the Coal segment had a significantly lower basis as a result of the purchase price allocation. The intangible assets and liabilities and property, plant and equipment were adjusted in connection with the application of fresh-start accounting. The amounts in the tables below remove the impact of purchase price adjustments included in 2012 results.
- Fresh-Start Adjustments—Upon emergence from bankruptcy on the Plan Effective Date, we applied fresh-start accounting which resulted in adjusting our assets and liabilities to their estimated fair values. As a result, our three and nine months ended September 30, 2013 results include the amortization of intangible assets and liabilities that did not exist in the three and nine months ended September 30, 2012. In addition, our property, plant and equipment had a significantly lower basis in the three and nine months ended September 30, 2013 as a result of the fresh-start adjustments. The amounts in the tables below remove the impact of the fresh-start adjustments included in our three and nine months ended September 30, 2013 results that have no corresponding amounts in our three and nine months ended September 30, 2012 results.

We believe providing a reconciliation of the impact of these significant items provides the basis for a more meaningful comparison of our three and nine months ended September 30, 2013 results to our three and nine months ended September 30, 2012 results.

Consolidated Summary Financial Information — Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

The following table provides summary financial data regarding our consolidated results of operations for the three months ended September 30, 2013 and 2012, respectively:

(amounts in millions)	Successor Three Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues	$446	$443	$ 3	1 %
Cost of sales	(290)	(312)	22	7 %
Gross margin, exclusive of depreciation shown separately below	156	131	25	19 %
Operating and maintenance expense, exclusive of depreciation shown separately below	(64)	(68)	4	6 %
Depreciation expense	(53)	(45)	(8)	(18)%
General and administrative expense	(22)	(29)	7	24 %
Acquisition and integration costs	(2)	—	(2)	(100)%
Operating income (loss)	15	(11)	26	236 %
Bankruptcy reorganization items, net	1	18	(17)	(94)%
Interest expense	(26)	(48)	22	46 %
Other income and expense, net	14	—	14	100 %
Income (loss) from continuing operations before income taxes	4	(41)	45	110 %
Income tax benefit	20	2	18	900 %
Income (loss) from continuing operations	24	(39)	63	162 %
Loss from discontinued operations, net of tax	(2)	(2)	—	— %
Net income (loss)	$22	$(41)	$ 63	154 %

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The following tables provide summary financial data regarding our operating income (loss) by segment for the three months ended September 30, 2013 and 2012, respectively:

	Successor Three Months Ended September 30, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$139	$307	$—	$446
Cost of sales	(122)	(168)	—	(290)
Gross margin, exclusive of depreciation shown separately below	17	139	—	156
Operating and maintenance expense, exclusive of depreciation shown separately below	(38)	(26)	—	(64)
Depreciation expense	(13)	(39)	(1)	(53)
General and administrative expense	—	—	(22)	(22)
Acquisition and integration costs (1)	—	—	(2)	(2)
Operating income (loss)	$(34)	$74	$(25)	$15

(1) Relates to costs associated with the pending AER Transaction. Please read Note 3—Acquisitions for further discussion.

	Predecessor Three Months Ended September 30, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$126	$317	$—	$443
Cost of sales	(122)	(190)	—	(312)
Gross margin, exclusive of depreciation shown separately below	4	127	—	131
Operating and maintenance expense, exclusive of depreciation shown separately below	(41)	(26)	(1)	(68)
Depreciation expense	(9)	(35)	(1)	(45)
General and administrative expense	—	—	(29)	(29)
Operating income (loss)	$(46)	$66	$(31)	$(11)

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

	Successor			
	Three Months Ended September 30, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Net income				$22
Loss from discontinued operations, net of tax				2
Income tax benefit				(20)
Bankruptcy reorganization items, net				(1)
Interest expense				26
Other items, net				(14)
Operating income (loss)	$(34)	$74	$(25)	$15
Depreciation expense	13	39	1	53
Bankruptcy reorganization items, net	—	—	1	1
Other items, net	—	—	14	14
EBITDA	(21)	113	(9)	83
Bankruptcy reorganization items, net	—	—	(1)	(1)
Acquisition and integration costs	—	—	2	2
Mark-to-market income, net	(6)	(23)	—	(29)
Amortization of intangible assets and liabilities (1)	31	32	—	63
Change in fair value of common stock warrants	—	—	(8)	(8)
Restructuring costs and other expenses	—	—	2	2
Other	2	(1)	—	1
Enterprise-wide Adjusted EBITDA	$6	$121	$(14)	$113

(1) In connection with the application of fresh-start accounting on the Plan Effective Date, we recorded intangible assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and gas transportation contracts. Please read Note 11—Intangible Assets and Liabilities for further discussion.

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The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the three months ended September 30, 2012:

(amounts in millions)	Predecessor Three Months Ended September 30, 2012 Coal	Gas	Other	Total
Net loss				$(41)
Loss from discontinued operations, net of tax				2
Income tax benefit				(2)
Bankruptcy reorganization items, net				(18)
Interest expense				48
Operating income (loss)	$(46)	$66	$(31)	$(11)
Depreciation expense	9	35	1	45
Bankruptcy reorganization items, net	—	—	18	18
EBITDA from continuing operations	(37)	101	(12)	52
Bankruptcy reorganization items, net	—	—	(18)	(18)
Restructuring costs and other expense	—	—	10	10
Amortization of intangible assets	37	9	—	46
Mark-to-market (income) loss, net	11	(53)	—	(42)
Adjusted EBITDA from continuing operations	$11	$57	$(20)	$48
Adjusted EBITDA from Legacy Dynegy (1)	—	—	2	2
Enterprise-wide Adjusted EBITDA	$11	$57	$(18)	$50

(1) Our consolidated results for the three months ended September 30, 2012 reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. The results of certain items related to Legacy Dynegy are not included in our consolidated results for the three months ended September 30, 2012. However, we have included the Adjusted EBITDA from Legacy Dynegy for this period in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating income:

(amounts in millions)	Three Months Ended September 30, 2012
Operating income	$25
Bankruptcy reorganization items, net	(8)
EBITDA	17
Bankruptcy reorganization items, net	8
Restructuring charges	(23)
Adjusted EBITDA from Legacy Dynegy	$2

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Discussion of Consolidated Results of Operations

Revenues. Revenues increased by $3 million from $443 million for the three months ended September 30, 2012 to $446 million for the three months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$446	$443	$ 3
Less:			
Fresh-start adjustments	(23)	—	(23)
Total as adjusted	$469	$443	$ 26

The $23 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with certain tolling, energy and capacity agreements related to our power generation facilities as a result of applying fresh-start accounting on the Plan Effective Date. After considering the impact of significant items, the increase in revenues was $26 million. Coal segment revenues increased by $13 million driven largely by mark-to-market changes. Gas segment revenues increased by $13 million driven by the absence of negative settlements associated with legacy put options and other negative financial settlements, partially offset by decreases in energy and gas revenues. Please read our Discussion of Segment Results of Operations below.

Cost of Sales. Cost of sales decreased by $22 million from $312 million for the three months ended September 30, 2012 to $290 million for the three months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$(290)	$(312)	$ 22
Less:			
DMG Acquisition	—	(37)	37
Fresh-start adjustments	(28)	—	(28)
Total as adjusted	$(262)	$(275)	$ 13

The $28 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with rail transportation, coal purchase and gas transportation contracts as a result of applying fresh-start accounting on the Plan Effective Date. The $37 million included in DMG Acquisition relates to the amortization of intangible assets and liabilities associated with our rail transportation and coal purchase contracts. After considering the impact of significant items, the decrease in cost of sales was $13 million. This decrease is primarily due to a reduction of gas purchases due to a decrease in spark spreads resulting in lower generation volumes in the Gas segment. Please read our Discussion of Segment Results of Operations below.

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Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. Operating and maintenance expense decreased by $4 million from $68 million for the three months ended September 30, 2012 to $64 million for the three months ended September 30, 2013. The decrease is primarily due to a decrease in Coal segment planned outage hours.

Depreciation Expense. Depreciation expense increased by $8 million from $45 million for the three months ended September 30, 2012 to $53 million for the three months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$ (53)	$ (45)	$ (8)
Less:			
DMG Acquisition	—	39	(39)
Fresh-start adjustments	29	—	29
Total as adjusted	$ (82)	$ (84)	$ 2

The $29 million included in Fresh-start adjustments relates to a lower basis in our power generation facilities as a result of applying fresh-start accounting on the Plan Effective Date. After considering the impact of significant items, the remaining decrease in depreciation expense was primarily related to the timing of various projects being placed into service.

General and Administrative Expense. General and administrative expense decreased by $7 million from $29 million for the three months ended September 30, 2012 to $22 million for the three months ended September 30, 2013. This decrease is primarily due to the allocation of expenses between Legacy Dynegy and Dynegy related to the Service Agreements in 2012. Partially offsetting the decrease were higher labor and benefit costs.

Acquisition and Integration Costs. Acquisition and integration costs totaled $2 million for the three months ended September 30, 2013 and were incurred in connection with our pending acquisition of AER. There were no such costs incurred during the three months ended September 30, 2012. Please read Note 3—Acquisitions for further discussion.

Bankruptcy Reorganization Items, Net. Bankruptcy reorganization items, net decreased by $17 million from $18 million for the three months ended September 30, 2012 to $1 million for the three months ended September 30, 2013. Bankruptcy reorganization items, net for the three months ended September 30, 2013 consisted primarily of professional and advisor fees. Bankruptcy reorganization items, net for the three months ended September 30, 2012 consisted primarily of a $26 million gain related to the change in the value of the Administrative Claim, partially offset by $7 million in expenses incurred related to advisors.

Interest Expense. Interest expense decreased by $22 million from $48 million for the three months ended September 30, 2012 to $26 million for the three months ended September 30, 2013. This decrease primarily relates to the early repayment of $325 million, in aggregate, of the outstanding balances related to the DPC and DMG credit agreements in the fourth quarter 2012 and lower interest rates on the new Credit Agreement and Senior Notes compared to the DPC and DMG credit agreements. Please read Note 18—Debt in our Form 10-K for further discussion.

Other Income and Expense, net. Other income and expense, net totaled $14 million for the three months ended September 30, 2013. Other income and expense, net consisted primarily of an $8 million gain due to a change in the fair value of our common stock warrants and certain insurance proceeds of $6 million during the three months ended September 30, 2013. There was no such activity during the three months ended September 30, 2012.

Income Tax Benefit. We reported an income tax benefit from continuing operations of $20 million and $2 million for the three months ended September 30, 2013 and September 30, 2012, respectively. The effective tax rate for the three months ended September 30, 2013 was negative 500 percent compared to five percent for the three months ended September 30, 2012.

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For the three months ended September 30, 2013, the difference between the effective rate and the statutory rate of 35 percent resulted primarily due to a change in our valuation allowance. During the three months ended September 30, 2013, our overall effective tax rate on continuing operations was affected by the recognition of a tax benefit in continuing operations that occurred as a result of offsetting tax expense recognized in income from discontinued operations and OCI. This was a result of the plan amendments and resulting remeasurements associated with certain of our pension and other post-employment benefit plans due to the negotiations with IBEW Local 51. In addition, during the three months ended September 30, 2013, we recorded tax expense for an uncertain tax position of $7 million pursuant to a proposed state assessment that we believe no longer meets the more likely than not criteria for recognizing a tax benefit. As of September 30, 2013, we do not believe we will produce sufficient future taxable income, nor are there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

For the three months ended September 30, 2012, the difference between the effective rate of five percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of September 30, 2012, we did not believe we would produce sufficient future taxable income, nor were there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

Income (Loss) from Discontinued Operations, Net of Tax. For the three months ended September 30, 2013 and 2012, our income (loss) from discontinued operations, net of tax primarily related to the DNE operations.

Enterprise-wide Adjusted EBITDA. Enterprise-wide Adjusted EBITDA increased by $63 million from $50 million for the three months ended September 30, 2012 to $113 million for the three months ended September 30, 2013. The increase was primarily due to an increase in the Gas segment Adjusted EBITDA due to the absence of negative settlements associated with legacy put options and other negative financial settlements which adversely impacted results in the prior year.

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Discussion of Segment Results of Operations

Coal Segment. Realized prices on both hedged and unhedged generation were generally lower during the three months ended September 30, 2013 compared to the three months ended September 30, 2012, resulting in lower gross margin.

The following table provides summary financial data regarding our Coal segment results of operations for the three months ended September 30, 2013 and 2012, respectively:

(dollars in millions)	Successor Three Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$146	$142	4	3 %
Mark-to-market income (loss), net	6	(12)	18	150 %
Other (1)	(13)	(4)	(9)	(225)%
Total operating revenues	$139	$126	$ 13	10 %
Operating Costs				
Cost of sales	(91)	(85)	(6)	(7)%
Contract amortization	(31)	(37)	6	16 %
Total operating costs	$(122)	$(122)	$ —	— %
Gross margin	$17	$4	$ 13	325 %
Operating and maintenance expense	(38)	(41)	3	7 %
Depreciation expense	(13)	(9)	(4)	(44)%
Operating loss	$(34)	$(46)	$ 12	26 %
Depreciation expense	13	9	4	44 %
EBITDA	$(21)	$(37)	$ 16	43 %
Mark-to-market (income) loss, net	(6)	11	(17)	(155)%
Amortization of intangible assets and liabilities	31	37	(6)	(16)%
Other	2	—	2	100 %
Adjusted EBITDA	$6	$11	$ (5)	(45)%
Million Megawatt Hours Generated (2)	5.5	4.9	0.6	12 %
In Market Availability for Coal-Fired Facilities (3)	90 %	93 %		
Average Quoted Market Power Prices ($/MWh) (4):				
On-Peak: Indiana (Indy Hub)	$38.41	$40.18	$ (1.77)	(4)%
Off-Peak: Indiana (Indy Hub)	$25.69	$24.34	$ 1.35	6 %

(1) Other includes financial settlements, ancillary services and other miscellaneous items.

(2) Reflects production volumes in million MWh generated.

(3) Reflects the percentage of generation available during periods when market prices are such that these units could be profitably dispatched.

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

Operating loss for the three months ended September 30, 2013 was $34 million compared to $46 million for the three months ended September 30, 2012. Adjusted EBITDA totaled $6 million during the three months ended September 30, 2013 compared to $11 million during the same period in 2012. The $5 million decrease in Adjusted EBITDA resulted from $15 million in lower realized prices on both hedged and unhedged generation, partially offset by a $6 million increase due to higher generation volumes and a $3 million reduction in the delivered cost of coal.

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Gas Segment. Spark spreads were generally lower in the three months ended September 30, 2013 compared to the three months ended September 30, 2012, resulting in lower generation volumes period over period. The following table provides summary financial data regarding our Gas segment results of operations for the three months ended September 30, 2013 and 2012, respectively:

(dollars in millions)	Successor Three Months Ended September 30, 2013	Predecessor Three Months Ended September 30, 2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$187	$203	$ (16)	(8)%
Capacity	74	51	23	45%
Mark-to-market income, net	23	53	(30)	(57)%
Contract amortization	(34)	(11)	(23)	(209)%
Other (1)	57	21	36	171%
Total operating revenues	$307	$317	$ (10)	(3)%
Operating Costs				
Cost of sales	(170)	(191)	21	11%
Contract amortization	2	1	1	100%
Total operating costs	$(168)	$(190)	$ 22	12%
Gross margin	$139	$127	$ 12	9%
Operating and maintenance expense	(26)	(26)	—	—%
Depreciation expense	(39)	(35)	(4)	(11)%
Operating income	$74	$66	$ 8	12%
Depreciation expense	39	35	4	11%
EBITDA	$113	$101	$ 12	12%
Mark-to-market income, net	(23)	(53)	30	57%
Amortization of intangible assets and liabilities	32	9	23	256%
Other	(1)	—	(1)	(100)%
Adjusted EBITDA	$121	$57	$ 64	112%
Million Megawatt Hours Generated (2)	4.7	6.2	(1.5)	(24)%
In Market Availability for Combined Cycle Facilities (3)	100%	100%		
Average Capacity Factor for Combined Cycle Facilities (4)	50%	61%		
Average Market On-Peak Spark Spreads ($/MWh) (5)	$21.09	$19.89	$ 1.20	6%
Average Market Off-Peak Spark Spreads ($/MWh) (5)	$4.79	$5.73	$ (0.94)	(16)%
Average natural gas price—Henry Hub ($/MMBtu) (6)	$3.55	$2.87	$ 0.68	24%

(1) Other includes ancillary services, RMR, tolls, natural gas, financial settlements, option premiums and other miscellaneous items.

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

(3) Reflects the percentage of generation available when market prices are such that these units could be profitably dispatched.

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

(5) Reflects the average of our on- and off-peak spark spreads at the following facilities: Commonwealth Edison (NI Hub), PJM West, North of Path 15 (NP 15), New York - Zone A and Mass Hub.

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

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Operating income for the three months ended September 30, 2013 was $74 million compared to $66 million for the three months ended September 30, 2012. Adjusted EBITDA totaled $121 million during the three months ended September 30, 2013 compared to $57 million during the same period in 2012. The $64 million increase in Adjusted EBITDA primarily resulted from $53 million due to the absence of negative settlements associated with legacy put options and other negative financial settlements and a $23 million increase in capacity revenues. These favorable results were partially offset by a $7 million decrease in physical energy margin due to a decrease in spark spreads, resulting in lower generation volumes.

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Consolidated Summary Financial Information — Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

The following table provides summary financial data regarding our consolidated results of operations for the nine months ended September 30, 2013 and 2012, respectively:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Revenues	$1,065	$981	$ 84	9 %
Cost of sales	(827)	(662)	(165)	(25)%
Gross margin, exclusive of depreciation shown separately below	238	319	(81)	(25)%
Operating and maintenance expense, exclusive of depreciation shown separately below	(220)	(150)	(70)	(47)%
Depreciation expense	(156)	(110)	(46)	(42)%
Gain on sale of assets, net	2	—	2	100 %
General and administrative expense	(69)	(66)	(3)	(5)%
Acquisition and integration costs	(6)	—	(6)	(100)%
Operating loss	(211)	(7)	(204)	(2,914)%
Bankruptcy reorganization items, net	(2)	147	(149)	(101)%
Interest expense	(71)	(120)	49	41 %
Loss on extinguishment of debt	(11)	—	(11)	(100)%
Impairment of Undertaking receivable, affiliate	—	(832)	832	100 %
Other income and expense, net	7	31	(24)	(77)%
Loss from continuing operations before income taxes	(288)	(781)	493	63 %
Income tax benefit	20	9	11	122 %
Loss from continuing operations	(268)	(772)	504	65 %
Income (loss) from discontinued operations, net of tax	3	(420)	423	101 %
Net loss	$(265)	$(1,192)	$ 927	78 %

The following tables provide summary financial data regarding our operating income (loss) by segment for the nine months ended September 30, 2013 and 2012, respectively:

	Successor Nine Months Ended September 30, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$341	$724	$—	$1,065
Cost of sales	(340)	(487)	—	(827)
Gross margin, exclusive of depreciation shown separately below	1	237	—	238
Operating and maintenance expense, exclusive of depreciation shown separately below	(130)	(89)	(1)	(220)
Depreciation expense	(36)	(118)	(2)	(156)
Gain on sale of assets, net	2	—	—	2
General and administrative expense	—	—	(69)	(69)
Acquisition and integration costs (1)	—	—	(6)	(6)
Operating income (loss)	$(163)	$30	$(78)	$(211)

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

	Predecessor Nine Months Ended September 30, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$166	$815	$—	$981
Cost of sales	(161)	(501)	—	(662)
Gross margin, exclusive of depreciation shown separately below	5	314	—	319
Operating and maintenance expense, exclusive of depreciation shown separately below	(55)	(95)	—	(150)
Depreciation expense	(13)	(91)	(6)	(110)
General and administrative expense	—	—	(66)	(66)
Operating income (loss)	$(63)	$128	$(72)	$(7)

The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the nine months ended September 30, 2013:

	Successor Nine Months Ended September 30, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(265)
Income from discontinued operations, net of tax				(3)
Income tax benefit				(20)
Bankruptcy reorganization items, net				2
Interest expense				71
Loss on extinguishment of debt				11
Other items, net				(7)
Operating income (loss)	$(163)	$30	$(78)	$(211)
Depreciation expense	36	118	2	156
Bankruptcy reorganization items, net	—	—	(2)	(2)
Other items, net	—	—	7	7
EBITDA	(127)	148	(71)	(50)
Bankruptcy reorganization items, net	—	—	2	2
Acquisition and integration costs	—	—	6	6
Mark-to-market (income) loss, net	16	(8)	—	8
Amortization of intangible assets and liabilities (1)	95	95	—	190
Change in fair value of common stock warrants	—	—	1	1
Restructuring costs and other expenses	—	—	5	5
Other	2	—	—	2
Enterprise-wide Adjusted EBITDA	$(14)	$235	$(57)	$164

(1) In connection with the application of fresh-start accounting on the Plan Effective Date, we recorded intangible assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and gas transportation contracts. Please read Note 11—Intangible Assets and Liabilities for further discussion.

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The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the nine months ended September 30, 2012:

	Predecessor			
	Nine Months Ended September 30, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(1,192)
Loss from discontinued operations, net of tax				420
Income tax benefit				(9)
Impairment of Undertaking receivable, affiliate				832
Bankruptcy reorganization items, net				(147)
Interest expense				120
Other items, net				(31)
Operating income (loss)	$(63)	$128	$(72)	$(7)
Depreciation expense	13	91	6	110
Impairment of Undertaking receivable, affiliate	—	—	(832)	(832)
Bankruptcy reorganization items, net	—	—	147	147
Other items, net	5	2	24	31
EBITDA from continuing operations	(45)	221	(727)	(551)
Impairment of Undertaking receivable, affiliate	—	—	832	832
Bankruptcy reorganization items, net	—	—	(147)	(147)
Interest income on Undertaking receivable	—	—	(24)	(24)
Restructuring costs and other expense	—	—	15	15
Amortization of intangible assets	49	29	—	78
Mark-to-market (income) loss, net	13	(127)	—	(114)
Premium adjustment	—	1	—	1
Adjusted EBITDA from continuing operations	$17	$124	$(51)	$90
Adjusted EBITDA from Legacy Dynegy (1)	21	—	(12)	9
Enterprise-wide Adjusted EBITDA	$38	$124	$(63)	$99

(1) Our consolidated results for the nine months ended September 30, 2012 reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Additionally, effective September 1, 2011, we completed the DMG Transfer and effective June 5, 2012, we completed the DMG Acquisition. As a result, the results of our Coal segment, related to Legacy Dynegy, were not included in our consolidated results for the period of January 1 through June 5, 2012. Additionally, the results of certain items in the Other segment related to Legacy Dynegy were not included in our consolidated results for the nine months ended September 30, 2012. However, we have included the Adjusted EBITDA from Legacy Dynegy for this period in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

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The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating income (loss):

	Nine Months Ended September 30, 2012		
(amounts in millions)	Coal	Other	Total
Operating income (loss)	$(2,701)	$1,669	$(1,032)
Depreciation expense	78	—	78
Bankruptcy reorganization items, net	—	(8)	(8)
Loss from unconsolidated investment	—	(1)	(1)
EBITDA	(2,623)	1,660	(963)
Loss (gain) on Coal Holdco Transfer	2,652	(1,711)	941
Bankruptcy reorganization items, net	—	8	8
Restructuring charges	—	30	30
Loss from unconsolidated investment	—	1	1
Mark-to-market income, net	(8)	—	(8)
Adjusted EBITDA from Legacy Dynegy	$21	$(12)	$9

Discussion of Consolidated Results of Operations

Revenues. Revenues increased by $84 million from $981 million for the nine months ended September 30, 2012 to $1,065 million for the nine months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$1,065	$981	$ 84
Plus:			
DMG Transfer	—	230	(230)
Less:			
Fresh-start adjustments	(69)	—	(69)
Total as adjusted	$1,134	$1,211	$ (77)

The $69 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with certain tolling, energy and capacity agreements related to our power generation facilities as a result of applying fresh-start accounting on the Plan Effective Date. After considering the impact of significant items, the decrease in revenues was $77 million with the Coal segment declining by $55 million and the Gas segment by $22 million. These decreases were primarily due to a reduction in mark-to-market revenues in both segments which was partially offset by the absence of negative settlements associated with legacy put options and other negative financial settlements in the Gas segment. Please read our Discussion of Segment Results of Operations below.

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Cost of Sales. Cost of sales increased by $165 million from $662 million for the nine months ended September 30, 2012 to $827 million for the nine months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$ (827)	$ (662)	$ (165)
Plus:			
DMG Transfer	—	(132)	132
Less:			
DMG Acquisition	—	(49)	49
Fresh-start adjustments	(92)	—	(92)
Total as adjusted	$ (735)	$ (745)	$ 10

The $92 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with rail transportation, coal purchase and gas transportation contracts as a result of applying fresh-start accounting on the Plan Effective Date. The $49 million included in DMG Acquisition relates to the amortization of intangible assets and liabilities associated with our rail transportation and coal purchase contracts. After considering the impact of significant items, the decrease in cost of sales was $10 million. This decrease is primarily due to a reduction in gas purchases due to a decrease in spark spreads resulting in lower generation volumes in the Gas segment, as further described in our Discussion of Segment Results of Operations below.

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. Operating and maintenance expense increased by $70 million from $150 million for the nine months ended September 30, 2012 to $220 million for the nine months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$ (220)	$ (150)	$ (70)
Plus:			
DMG Transfer	—	(69)	69
Total as adjusted	$ (220)	$ (219)	$ (1)

After considering the impact of significant items, the $1 million increase in operating and maintenance expense was relatively consistent compared to the nine months ended September 30, 2012.

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Depreciation Expense. Depreciation expense increased by $46 million from $110 million for the nine months ended September 30, 2012 to $156 million for the nine months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$(156)	$(110)	$ (46)
Plus:			
DMG Transfer	—	(78)	78
Less:			—
DMG Acquisition	—	53	(53)
Fresh-start adjustments	96	—	96
Total as adjusted	$(252)	$(241)	$ (11)

After considering the impact of significant items, the increase in depreciation expense was $11 million, which is primarily due to a benefit of $16 million in the first quarter 2012 due to a reduction in our asset retirement obligations associated with the South Bay facility with no similar benefit in 2013, offset by decreases due to timing of various projects being placed into service.

General and Administrative Expense. General and administrative expense increased by $3 million from $66 million for the nine months ended September 30, 2012 to $69 million for the nine months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$(69)	$(66)	$ (3)
Plus:			
DMG Transfer	—	(14)	14
Total as adjusted	$(69)	$(80)	$ 11

After considering the impact of significant items, the decrease in general and administrative expense was $11 million. This decrease is primarily due to the allocation of expenses between Legacy Dynegy and Dynegy related to the Service Agreements in 2012 and lower legal expenses in the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. Partially offsetting these decreases were higher labor and benefit costs.

Acquisition and Integration Costs. Acquisition and integration costs totaled $6 million for the nine months ended September 30, 2013 and were incurred in connection with our pending acquisition of AER. There were no such costs incurred during the nine months ended September 30, 2012. Please read Note 3—Acquisitions for further discussion.

Bankruptcy Reorganization Items, Net. Bankruptcy reorganization items, net decreased by $149 million from a gain of $147 million for the nine months ended September 30, 2012 to a loss of $2 million for the nine months ended September 30, 2013. The 2013 Bankruptcy reorganization items, net consisted primarily of professional and advisor fees. The 2012 Bankruptcy reorganization items, net consisted primarily of reductions of approximately $161 million and $10 million in the estimated allowable claims related to the subordinated debt and other items, respectively. Additionally, there was a gain of approximately $17 million related to the change in the value of the Administrative

Claim, partially offset by $40 million in expenses incurred related to advisors.

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Interest Expense. Interest expense decreased by $49 million from $120 million for the nine months ended September 30, 2012 to $71 million for the nine months ended September 30, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change
As reported	$(71)	$(120)	$ 49
Plus:			
DMG Transfer	—	(24)	24
Less:			
Fresh-start adjustments	8	—	8
Total as adjusted	$(79)	$(144)	$ 65

The $8 million included in Fresh-start adjustments related to amortization of the premium recorded in connection with adjusting our outstanding debt to its fair value in connection with the application of fresh-start accounting on the Plan Effective Date. After considering the impact of significant items, the decrease in interest expense was $65 million, which primarily related to the early repayment of $325 million, in aggregate, of the outstanding balances related to the DPC and DMG credit agreements in the fourth quarter 2012 and lower interest rates on the new Credit Agreement and Senior Notes compared to the DPC and DMG credit agreements. Please read Note 12—Debt included herein and Note 18—Debt—DPC and DMG Credit Agreements in our Form 10-K for further discussion.

Loss on Extinguishment of Debt. Loss on extinguishment of debt totaled $11 million for the nine months ended September 30, 2013 and were incurred in connection with the termination of the DPC and DMG credit agreements and the Term Loan B-1. The amount is comprised of (i) a prepayment penalty of approximately $59 million, (ii) $2 million for the accelerated amortization of the discount on the Term Loan B-1 and (iii) $6 million in accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Term Loan B-1, offset by (iv) $56 million in non-cash gains for the accelerated amortization of the remaining premium related to the DPC and the DMG credit agreements. Please read Note 12—Debt for further discussion. There was no similar activity during the nine months ended September 30, 2012.

Impairment of Undertaking Receivable, Affiliate. As a result of entering into the Settlement Agreement, the Undertaking receivable was impaired to approximately $418 million as of March 31, 2012, resulting in a charge of approximately $832 million for the nine months ended September 30, 2012. The carrying value of the Undertaking was adjusted to the value received in the DMG Acquisition plus interest payments received subsequent to March 31, 2012. The Undertaking was settled upon execution of the Settlement Agreement; therefore, there were no such charges during the nine months ended September 30, 2013.

Other Income and Expense, net. Other income and expense, net decreased by $24 million from income of $31 million for the nine months ended September 30, 2012 to income of $7 million for the nine months ended September 30, 2013. The decrease was primarily due to interest income on the Undertaking receivable, affiliate during the nine months ended September 30, 2012. The Undertaking was executed on September 1, 2011, impaired as of March 31, 2012 and settled on June 5, 2012; therefore, there are three months of interest income related to the Undertaking during the nine months ended September 30, 2012. The Undertaking was settled upon execution of the Settlement Agreement; therefore, there is no interest income related to the Undertaking during the nine months ended September 30, 2013. Additionally, the decrease was partially due to a $1 million loss due to a change in the fair value of our common stock warrants for the nine months ended September 30, 2013. The remaining decrease is primarily due to a $5 million distribution received related to our retained profits interest in Plum Point for the nine months ended September 30, 2012. Partially offsetting these decreases were certain insurance proceeds of $8 million for the nine months ended September 30, 2013.

Income Tax Benefit. We reported an income tax benefit from continuing operations of $20 million and $9 million for the nine months ended September 30, 2013 and September 30, 2012, respectively. The effective tax rate for the nine months ended September 30, 2013 was seven percent compared to one percent for the nine months ended September 30, 2012.

For the nine months ended September 30, 2013, the difference between the effective rate of seven percent and the statutory rate of 35 percent resulted primarily from a change in our valuation allowance. During the nine months ended

September 30, 2013, our overall effective tax rate on continuing operations was affected by the recognition of a tax benefit in continuing operations that occurred as a result of offsetting tax expense recognized in income from discontinued operations and OCI. This was a result of the plan amendments and resulting remeasurements associated with certain of our pension and post-employment benefit plans due to the negotiations with IBEW Local 51. In addition, during the nine months ended September 30, 2013, we recorded tax expense for an uncertain tax position of $7 million pursuant to a proposed state assessment that we believe no longer meets the more likely than not criteria for recognizing a tax benefit. As of September 30, 2013, we do not believe we will produce sufficient future taxable income, nor are there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

For the nine months ended September 30, 2012, the difference between the effective rate of one percent and the statutory rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of September 30, 2012, we did not believe we would produce sufficient future taxable income, nor were there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

Income (Loss) from Discontinued Operations, Net of Tax. For the nine months ended September 30, 2013 and 2012, our income (loss) from discontinued operations, net of tax primarily related to the DNE operations. During the nine months ended September 30, 2013, our income from discontinued operations, net of tax was $3 million, primarily related to a $7 million DNE pension curtailment gain due to the termination of a majority of the Danskammer employees and closing the Roseton sale, offset by a $2 million loss related to legacy capacity contracts executed with the Roseton facility which terminated upon the sale of the facility. During the nine months ended September 30, 2012, our loss from discontinued operations, net of tax was $420 million, primarily related to Bankruptcy reorganization items, net of $399 million, which included a $395 million charge related to the estimated claim for the rejection of the DNE Facilities Lease and $4 million related to other items.

Enterprise-wide Adjusted EBITDA. Enterprise-wide Adjusted EBITDA increased by $65 million from $99 million for the nine months ended September 30, 2012 to $164 million for the nine months ended September 30, 2013. The increase was primarily due to an increase in the Gas segment Adjusted EBITDA due to the absence of negative settlements associated with legacy put options and other negative financial settlements. Offsetting the increase was a decrease in the Coal segment Adjusted EBITDA due to lower realized prices on hedged generation.

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Discussion of Segment Results of Operations
Coal Segment. Realized prices on hedged generation were generally lower during the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012, resulting in lower gross margin. As a result of the DMG Transfer, the results of our Coal segment are only included in our consolidated results subsequent to June 5, 2012; however, we have included the results of our Coal segment for the period of January 1 through June 5, 2012, related to Legacy Dynegy, in our combined results for the nine months ended September 30, 2012 for comparative purposes.
The following table provides summary financial data regarding our Coal segment results of operations for the nine months ended September 30, 2013 and 2012, respectively:

	Successor	Predecessor	Legacy Dynegy	Combined		
(dollars in millions)	Nine Months Ended September 30, 2013	June 6 Through September 30, 2012	January 1 Through June 5, 2012	Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues						
Energy	$376	$184	$193	$377	$ (1)	— %
Mark-to-market income (loss), net	(16)	(14)	9	(5)	(11)	(220)%
Other (1)	(19)	(4)	28	24	(43)	(179)%
Total operating revenues	$341	$166	$230	$396	$ (55)	(14)%
Operating Costs						
Cost of sales	(245)	(112)	(132)	(244)	(1)	— %
Contract amortization	(95)	(49)	—	(49)	(46)	(94)%
Total operating costs	$(340)	$(161)	$(132)	$(293)	$ (47)	(16)%
Gross margin	$1	$5	$98	$103	$ (102)	(99)%
Operating and maintenance expense	(130)	(55)	(69)	(124)	(6)	(5)%
Depreciation expense	(36)	(13)	(78)	(91)	55	60 %
Loss on Coal Holdco Transfer	—	—	(2,652)	(2,652)	2,652	100 %
Gain on sale of assets, net	2	—	—	—	2	100 %
Operating loss	$(163)	$(63)	$(2,701)	$(2,764)	$ 2,601	94 %
Depreciation expense	36	13	78	91	(55)	(60)%
Other items, net	—	5	—	5	(5)	(100)%
EBITDA	$(127)	$(45)	$(2,623)	$(2,668)	$ 2,541	95 %
Mark-to-market (income) loss, net	16	13	(8)	5	11	220 %
Amortization of intangible assets and liabilities	95	49	—	49	46	94 %
Loss on Coal Holdco Transfer	—	—	2,652	2,652	(2,652)	(100)%
Other	2	—	—	—	2	100 %
Adjusted EBITDA	$(14)	$17	$21	$38	$ (52)	(137)%
Million Megawatt Hours Generated (2)	14.9	6.6	8.5	15.1	(0.2)	(1)%
	90 %	93 %	93 %	93 %		

In Market Availability for Coal-Fired Facilities (3)							
Average Quoted Market Power Prices ($/MWh) (4):							
On-Peak: Indiana (Indy Hub)	$38.11	$39.72	$30.41	$34.54	$ 3.57	10	%
Off-Peak: Indiana (Indy Hub)	$27.17	$23.88	$24.25	$24.08	$ 3.09	13	%

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(1) Other includes financial settlements, ancillary services and other miscellaneous items.

(2) Reflects production volumes in million MWh generated during the period that Coal was included in our consolidated results and during the period that Coal was included in Legacy Dynegy's consolidated results during the nine months ended September 30, 2013 and 2012, respectively.

(3) Reflects the percentage of generation available during the period that Coal was included in our consolidated results and during the period that Coal was included in Legacy Dynegy's consolidated results during the nine months ended September 30, 2013 and 2012, respectively, when market prices are such that these units could be profitably dispatched.

(4) Reflects the average of day-ahead quoted prices for the period that Coal was included in our consolidated results and during the period that Coal was included in Legacy Dynegy's consolidated results during the nine months ended September 30, 2013 and 2012, respectively, and does not necessarily reflect prices we realized.

Operating loss for the nine months ended September 30, 2013 was $163 million compared to $63 million for the nine months ended September 30, 2012. On a combined basis, operating loss was $2,764 million, or $112 million excluding the loss on the Coal Holdco Transfer. Adjusted EBITDA was a loss of $14 million during the nine months ended September 30, 2013 compared to income of $38 million during the same period in 2012. The $52 million decrease in Adjusted EBITDA resulted primarily from $31 million in lower realized prices on hedged generation, an $11 million increase in rail transportation costs as a result of the rail contract modification occurring in 2012 and a $6 million increase in operating expenses, primarily at Baldwin and Hennepin.

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Gas Segment. Spark spreads were generally lower in the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012, resulting in lower generation volumes period over period. Volumes also decreased due to an increase in outage hours. The following table provides summary financial data regarding our Gas segment results of operations for the nine months ended September 30, 2013 and 2012, respectively:

(dollars in millions)	Successor Nine Months Ended September 30, 2013	Predecessor Nine Months Ended September 30, 2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Operating Revenues				
Energy	$488	$492	$ (4)	(1)%
Capacity	182	194	(12)	(6)%
Mark-to-market income, net	8	117	(109)	(93)%
Contract amortization	(101)	(32)	(69)	(216)%
Other (1)	147	44	103	234%
Total operating revenues	$724	$815	$ (91)	(11)%
Operating Costs				
Cost of sales	(493)	(504)	11	2%
Contract amortization	6	3	3	100%
Total operating costs	$(487)	$(501)	$ 14	3%
Gross margin	$237	$314	$ (77)	(25)%
Operating and maintenance expense	(89)	(95)	6	6%
Depreciation expense	(118)	(91)	(27)	(30)%
Operating income	$30	$128	$ (98)	(77)%
Depreciation expense	118	91	27	30%
Other items, net	—	2	(2)	(100)%
EBITDA	$148	$221	$ (73)	(33)%
Mark-to-market income, net	(8)	(127)	119	94%
Amortization of intangible assets and liabilities	95	29	66	228%
Premium adjustment	—	1	(1)	(100)%
Adjusted EBITDA	$235	$124	$ 111	90%
Million Megawatt Hours Generated (2)	12.5	16.9	(4.4)	(26)%
In Market Availability for Combined Cycle Facilities (3)	98%	98%		
Average Capacity Factor for Combined Cycle Facilities (4)	44%	57%		
Average Market On-Peak Spark Spreads ($/MWh) (5)	$16.05	$15.04	$ 1.01	7%
Average Market Off-Peak Spark Spreads ($/MWh) (5)	$3.80	$4.71	$ (0.91)	(19)%
Average natural gas price—Henry Hub ($/MMBtu) (6)	$3.68	$2.53	$ 1.15	45%

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(1) Other includes ancillary services, RMR, tolls, natural gas, financial settlements, option premiums and other miscellaneous items.
(2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility.
(3) Reflects the percentage of generation available when market prices are such that these units could be profitably dispatched.
(4) Reflects actual production as a percentage of available capacity.
(5) Reflects the average of our on- or off-peak spark spreads at the following facilities: Commonwealth Edison (NI Hub), PJM West, North of Path 15 (NP 15), New York - Zone A and Mass Hub.
(6) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Operating income for the nine months ended September 30, 2013 was $30 million compared to $128 million for the nine months ended September 30, 2012. Adjusted EBITDA totaled $235 million during the nine months ended September 30, 2013 compared to $124 million during the same period in 2012. The $111 million increase in Adjusted EBITDA primarily resulted from $130 million due to the absence of negative settlements associated with legacy put options and other negative financial settlements during 2012. These favorable results were partially offset by an $11 million reduction in energy margin due to a decrease in spark spreads resulting in lower generation volumes.

Outlook

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

On March 14, 2013, IPH entered into the AER Transaction Agreement, whereby IPH will acquire AER (or, following a pre-closing reorganization contemplated by Ameren, a successor thereto) and its subsidiaries. There is no cash consideration or stock issued as part of the purchase price. Genco's debt will remain outstanding. The transaction is subject to certain closing conditions and the receipt of regulatory approvals. On October 11, 2013, AER and IPH received FERC Approval and in August 2013, they received FCC Approval. On June 6, 2013, the IPCB rejected, on procedural grounds, AER's and IPH's motion to transfer variance relief from Illinois' Multi-Pollutant Standard. The IPCB indicated that IPH may file a request for variance relief on its own behalf. IPH and AER are pursuing such relief, and on July 22, 2013 IPH and certain co-petitioners filed their request for variance relief and a hearing was held on September 17, 2013. The IPCB is expected to make its decision on that request on or before November 21, 2013. Pending the receipt of variance relief, the closing is expected to occur in December 2013. Please read Note 3—Acquisitions—AER Transaction Agreement for further discussion.

Coal. The Coal segment consists of four plants, all located in the MISO region, totaling 2,980 MW. The discussion below does not include any potential impacts associated with the pending AER transaction.

As of November 4, 2013, our Coal expected generation volumes are 60 percent hedged volumetrically for 2013 and approximately 36 percent hedged volumetrically for 2014. We plan to continue our hedging program for Coal over a one- to three-year period using various instruments, which includes the sale of natural gas swaps as a cross-commodity correlated hedge for our power revenue. As a result of the offsetting risks of our Coal and Gas segments, we are able to reduce the costs associated with hedging by executing a portion of Coal's hedges with an internal affiliate. The internal hedges are cross-commodity hedges and we intend to expand this in the future. Beyond 2013, the portfolio is largely open, positioning Coal to benefit from possible future power market pricing improvements.

Due to declining correlations between our plant LMP prices and trading hub prices, we plan to mitigate the risk of a breakdown between these prices through participation in FTR markets and busbar basis swaps to the extent they are economically available. Furthermore, Coal's hedge levels are likely to be lower than the hedge levels in prior years.

Currently, our expected coal requirements are fully contracted and priced in 2013. Our forecasted coal requirements for 2014 are 93 percent contracted and priced. Our coal transportation requirements are fully contracted and priced for the next several years. We continue to explore various alternative contractual commitments and financial options, as well as facility modifications, to ensure stable and competitive fuel supplies and to mitigate further supply risks for near- and long-term coal supplies.

The MISO filed proposed Resource Adequacy Enhancements with FERC on July 20, 2011. The FERC conditionally approved MISO's proposal on June 11, 2012, leaving much of MISO's proposal in place. The new tariff provisions replace the monthly construct with a full planning year product (June 1 - May 31) and further recognize zonal deliverability capacity requirements. The first zonal auction was held in March 2013. For the 2013-2014 planning year, capacity cleared at $1.05 per MW-day for all zones. This low clearing price was likely caused by excess capacity conditions prevailing in MISO for the term of the planning year. In the future, the potential retirement of marginal MISO coal capacity due to poor economics or expected environmental mandates and confirmed future capacity exports from MISO to PJM could also affect MISO capacity and energy pricing.

MISO's annual Loss of Load Expectation ("LOLE") study was published in early November 2013. The LOLE study is a critical input to the annual MISO Planning Resource Auction ("PRA"). The LOLE study employed meaningful changes for the planning year 2014-2015 to reflect the integration of Entergy into MISO and to reflect modeling enhancements required to stabilize the planning reserve margin and reliability requirements in MISO. The LOLE also utilizes a revised methodology to calculate import and export capabilities between Local Resource Zones ("LRZ") which may have an impact on intra-zonal balances.

We have initiated various studies of the MISO transmission grid to identify opportunities to reduce congestion and improve the busbar power prices at our coal-fired facilities.

In March 2013, we began negotiations with IBEW Local 51 regarding its collective bargaining agreement, which expired, following an extension, on July 8, 2013. This agreement covers approximately 400 represented employees at our four Coal plants located in Illinois. On August 1, 2013, we and IBEW Local 51 reached a tentative agreement on a new collective bargaining agreement. On September 20, 2013, following a voting process conducted by IBEW Local 51, the tentative agreement was successfully ratified by employees and resulted in amendments to certain pension and other post-employment benefit plans. As a result of these amendments and resulting remeasurements, we significantly reduced our benefit obligations under the affected plans. This new agreement, which expires on June 30, 2017, further aligns our near-term and long-term strategic priorities. Please read Note 16—Pension and Other Post-Employment Benefit Plans for further discussion.

Gas. The Gas segment consists of eight plants, geographically diverse in five markets, totaling 6,771 MW. Approximately 50 percent of our power plant capacity in the CAISO market is contracted through 2013 under tolling agreements with LSEs and a RMR agreement. A significant portion of the remaining capacity is sold as a resource adequacy product in the CAISO market.

The CAISO capacity market is bilateral in nature. The LSEs are required to procure sufficient resources for their peak load plus a 15 percent reserve margin. The CAISO footprint currently has a capacity surplus due to a weak economy and increased participation from renewable resources. The CAISO faces challenges to ensure system reliability as well as adequate ancillary services in the future with the mandate to have 33 percent renewable resources by 2020. The combination of bilateral markets, one-off utility procurements and short-term requirements make this a larger concern than in other markets where multi-year forward requirements and more transparent markets are in place. The CAISO and CPUC recently released a joint proposal for a multi-year forward capacity market called the Joint Reliability Framework. This proposal would fill the gap between the Resource Adequacy (one year requirement) and the LTPP (ten year plan) to establish a multi-year forward resource adequacy requirement on LSEs, provide a CAISO administered multi-year forward capacity market, and a market-based backstop mechanism to procure reliability services (both capacity and flexibility). This new capacity auction is called the Reliability Services Auction. CAISO intends to solicit feedback from stakeholders on its proposal.

In May 2012, SCE notified DMB and DML, that it was terminating certain energy and capacity contracts with those entities. The terminations were disputed by Dynegy in parallel arbitration and federal court litigation. On October 10,

2013, Dynegy and SCE agreed to resolve the dispute by entering into two new transactions between SCE and DML. Under the first transaction, SCE agreed to purchase energy and capacity from Units 6 & 7 of the Moss Landing Energy Facility for 2014 and 2015 and, under the second transaction, to purchase energy and capacity from Units 6 & 7 for 2016. The 2016 transaction is conditioned on approval by the CPUC, which both SCE and Dynegy have agreed to seek in good faith and use commercially reasonable efforts to obtain. The pending arbitration and federal court litigation have been dismissed as a result of the new transactions.
The South Bay power generation facility has been permanently retired and is currently in the process of being

demolished. We have a contractual obligation to demolish the facility and potentially remediate specific parcels of the property. The first phase of the demolition is largely complete as the above ground portion of the facility has been demolished and removed. The second phase will consist of the below ground structures. Our estimates for the demolition and any potential remediation costs may change as the project advances through the next phase of the demolition process. We currently expect the escrowed funds to cover costs through 2014.

The estimated useful lives of our generation facilities consider environmental regulations currently in place. With respect to Units 6 and 7 at our Moss Landing facility, we are continuing to review the potential impact of the California Water Intake Policy. We are currently depreciating these units through 2024; however, depending on (i) a final determination of the compliance term and requirements of the California Water Intake Policy and (ii) our ability to secure energy and/or capacity contracts in the future, we could decide to reduce operations or cease to operate the units prior to 2024. Furthermore, we have been unsuccessful in attaining resource adequacy awards or tolling agreements that would sufficiently cover on-going operating expenses at our Morro Bay facility; therefore, we are initiating the retirement process for the Morro Bay facility with the CPUC, CAISO and CEC and notifying them that the Morro Bay facility will close once the relevant processes are complete. Dynegy is currently evaluating alternatives for the site including developing renewable energy shaping technologies as well as preferred renewable resources, as defined by California laws and regulations, at the site with Starwood Energy Group Global, Inc.

In New England, seven forward capacity auctions have been held since the ISO-NE transitioned to a forward capacity market in June 2010. Capacity clearing prices have ranged from a high of $4.50 per kW-month for the 2010-2011 market period to a low of $2.95 per kW-month for the 2013-2014 market period. The most recent capacity auction, for 2016-2017, cleared at the floor price of $3.15 per kW-month. The annual auctions continue to clear at the designated floor due to oversupply conditions. Recent changes made to the forward capacity market design include removal of the auction floor price and implementation of a minimum offer price rule that sets a floor price for new entrants based on technology type. The changes will be effective for Forward Capacity Auction #8, covering the 2017-2018 delivery year.

In PJM, where the Kendall and Ontelaunee combined-cycle plants are located, ten forward capacity auctions (known as RPM or Reliability Pricing Model) have been held since the transition from a daily capacity market in June 2007. RPM clearing prices have ranged from $0.50 per kW-month (Kendall, 2012-2013 Planning Year) and $1.24 per kW-month (Ontelaunee, 2007-2008 Planning Year) to $5.30 per kW-month (Kendall, 2010-2011 Planning Year) and $6.88 per kW-month (Ontelaunee, 2013-2014 Planning Year). The latest RPM auction was for the 2016-2017 Planning Year, which cleared at $1.81 per kW-month (Kendall) and $3.62 per kW-month (Ontelaunee).

Capacity pricing for the NYISO seems to be recovering from the low point in 2011. The most recent summer and winter auctions have cleared higher than the previous auctions with summer 2013 at $4.20 per kW-month and winter 2013-2014 at $2.58 per kW-month for the rest of state market. We attribute the rebound in part due to the FERC Order on buyer-side mitigation and retirements impacting 2013. Approximately 70 percent of the capacity revenue for our Independence facility has been contracted at a favorable premium compared to current market prices through October 31, 2014.

Excluding volumes subject to tolling agreements, as of November 4, 2013, our Gas portfolio is 77 percent hedged volumetrically through 2013 and approximately 37 percent hedged volumetrically for 2014. As a result of the offsetting risks of our Gas and Coal segments, we are able to reduce the costs associated with hedging by executing a portion of our natural gas purchases with an internal affiliate. As discussed above, we intend to expand this in the future.

We plan to mitigate the risk of a potential breakdown between plant LMP prices and trading hub prices through participation in FTR markets and busbar basis swaps to the extent they are economically available. Furthermore, Gas hedge levels are likely to be lower than the hedge levels in prior years.

Environmental and Regulatory Matters

Please read Item 1. Business-Environmental Matters in our Form 10-K and Outlook-Environmental and Regulatory Matters in our Form 10-Q for the periods ended March 31, 2013 and June 30, 2013 for a detailed discussion of our environmental and regulatory matters.

The Dodd-Frank Act

The CFTC has regulatory oversight authority over the trading of electricity and gas commodities, including financial products and derivatives, under the Commodity Exchange Act. On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), which, among other things, aims to improve transparency in derivative markets. The Dodd-Frank Act increases the CFTC’s regulatory authority on matters related to over-the-counter derivatives, market clearing, position reporting and capital requirements. On April 10, 2013, certain record-keeping and reporting requirements went into effect for Non-Swap Dealers/Non-Major Swap Participants, as defined by the CFTC.

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Beginning on April 5, 2013, the CFTC Staff issued various materials, including "No Action" letters, which delayed the effectiveness or otherwise altered many of these requirements. Dynegy has systems in place in order to monitor our swap activity and comply with Non-Swap Dealer/Major Swap Participant reporting requirements. As required, Dynegy is meeting its reporting obligations under Parts 43, 45 and 46 of the CFTC's regulations, which cover real-time public reporting of swap transaction data, reporting of swap transaction data to a registered swap data repository and reporting of historical swaps. We continue to monitor the CFTC's releases for guidance on these rules and any other clearing and reporting requirements that will be required of our business or impact current operations.

The Clean Air Act

Cross-State Air Pollution Rule. On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CSAPR and ordered the EPA to continue administering the CAIR pending the promulgation of a valid replacement rule. In June 2013, the Supreme Court granted petitions to review the appellate court's decision vacating the CSAPR. The Court is expected to issue its decision by June 2014. We will continue to monitor rulemaking, judicial and legislative developments regarding the CSAPR and a possible replacement rule and evaluate any potential impacts on our operations.

NAAQS. In June 2013, the EPA announced that it intends to delay rulemaking action concerning the ozone NAAQS until mid- to late-2014. The EPA had initially planned to complete its ongoing five-year review process of the current ozone NAAQS in December 2013.

In August 2013, the EPA issued initial nonattainment area designations for the one-hour SO_2 NAAQS. No areas in which our facilities are located were designated nonattainment with the one-hour SO_2 NAAQS.

In October 2013, the Illinois EPA proposed to identify the Metro-East St. Louis area as nonattainment with the 2012 PM2.5 NAAQS, including Madison County, the location of our Wood River facility, and Baldwin Township in Randolph County, the location of our Baldwin facility. The nature and scope of potential future requirements resulting from a nonattainment designation for this area cannot be predicted with confidence at this time, but a requirement for additional emission reductions at any of our facilities for purposes of the PM2.5 NAAQS may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

The Clean Water Act

Effluent Limitation Guidelines. In spring 2013, the EPA proposed revisions to the Effluent Limitation Guidelines ("ELG") for steam electric power generation units. The proposed rule would establish new or additional requirements for wastewater streams associated with steam electric power generation processes and byproducts, including flue gas desulfurization, fly ash, bottom ash, and flue gas mercury control. The proposed rule identifies four preferred options for regulation of discharges from existing sources, with the options differing in the number of waste streams covered, the size of the units controlled, and the stringency of the controls to be imposed. As proposed, the new ELG requirements would be phased in between 2017 and 2022. The EPA is expected to take final action on the proposal by May 22, 2014 and intends to align the ELG rule with its related CCR rule proposed in 2010. The timing and ultimate requirements of the final ELG rule and options available for compliance cannot be predicted with confidence at this time but could have a material adverse effect on our financial condition, results of operations and cash flows.

Cooling Water Intake Structures. On March 28, 2011, the EPA released a proposed rule for cooling water intake structures at existing facilities that would establish national standards for impingement mortality and entrainment. Under an amended settlement agreement, the EPA is expected to issue its final rule on cooling water intake structures by November 20, 2013. The scope of requirements, timing for compliance and the compliance methodologies that will ultimately be allowed under the final rule potentially may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

Dam Safety Assessment Reports

In March 2013, the EPA issued final dam safety assessment reports of the surface impoundments at our Baldwin and Hennepin facilities. The reports rate the impoundments at each facility as "poor," meaning that a deficiency is recognized for a required loading condition in accordance with applicable dam safety criteria. A poor rating also applies when further critical studies are needed to identify any potential dam safety deficiencies. The reports include recommendations for further studies, repairs, and changes in operational and maintenance practices. We plan on performing the other recommended further studies and actions at Baldwin and Hennepin, some of which are dependent on necessary permits being obtained. The nature and scope of repairs that ultimately may be needed, if any, cannot be predicted with confidence at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

Coal Combustion Residuals

On September 30, 2013, the U.S. District Court for the District of Columbia issued an order in a case that may affect when the EPA issues its CCR final regulations. It is unclear at this time whether the court will set a deadline for the EPA to issue its CCR final rule.

In August 2013, the EPA issued a Notice of Data Availability regarding its June 2010 proposed CCR rule, seeking comments on a limited number of issues, including new data relevant to updating the risk assessment for the proposed rule, additional information on surface impoundment structural stability, and time frames for closing surface impoundments. In July 2013, the U.S. House of Representatives passed H.R. 2218, the Coal Residuals Reuse and Management Act of 2013, which would establish a non-hazardous regulatory framework to govern the disposal of CCR. Similar legislation is expected to be introduced in the U.S. Senate.

In late October 2013, the Illinois EPA issued a proposed rule that would establish processes governing monitoring, preventative response, corrective action and closure of CCR surface impoundments at power generating facilities. We are reviewing the proposed rule for potential impacts on our operations and anticipate participating in the rulemaking process. The requirements that will ultimately be included in a final rule potentially may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

Vermilion and Baldwin Groundwater. We have implemented hydrogeologic investigations for the CCR surface impoundment at our Baldwin facility and for two CCR surface impoundments at our Vermilion facility in response to requests by the Illinois EPA. Groundwater monitoring results indicate that the CCR surface impoundments at each site impact onsite groundwater.

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In December 2012, the Illinois EPA provided written notice that it may pursue legal action with respect to each matter through referral to the Illinois Office of the Attorney General. In accordance with work plans approved by the Illinois EPA, we have initiated a six month geotechnical study at Vermilion and have begun a twelve month geotechnical/hydraulic/hydrogeologic study needed to analyze corrective action alternatives at Baldwin. At this time, we cannot reasonably estimate the costs of resolving these matters, but resolution of these matters may cause us to incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows.

Climate Change

Federal Regulation of Greenhouse Gases. In June 2013, President Obama announced his Administration's plan to address climate change. In accordance with the plan, in September 2013, the EPA re-proposed GHG NSPS for new electric generating units, with separate standards for natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined cycle ("IGCC") units. New natural gas-fired units with a heat input rating greater than 850 MMBtu/hour would be limited to 1,000 pounds of carbon dioxide per megawatt-hour gross output ("lb CO_2/MWh") and smaller natural gas-fired units would be limited to 1,100 lb CO_2/MWh, with each standard as a 12-operating month rolling average. New fossil fuel-fired utility boilers or IGCC units would be limited to 1,100 lb CO_2/MWh as a 12-operating month rolling average or 1,000-1,050 lb CO_2/MWh as an 84-operating month rolling average. The proposed limits for fossil fuel-fired utility boilers and IGCC units are based on the performance of a new efficient coal unit implementing partial carbon capture and storage. A final rule is expected in 2014.

The Administration's climate change plan also directs the EPA to propose carbon emission standards for existing electric generating units by June 1, 2014, and to finalize such standards by June 1, 2015. Under the plan, state implementation plans addressing existing electric generating units would be due by June 30, 2016. The nature and scope of carbon emission requirements, if any, that ultimately may be imposed on existing electric generating units cannot be predicted with confidence at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

State Regulation of Greenhouse Gases. In September 2013, CARB released proposed amendments to its GHG cap-and-trade program rule to provide additional clarity in implementation, address cost containment issues, add a new compliance offset protocol and extend transition assistance for covered entities. CARB also proposed to amend its mandatory GHG reporting rule to support its proposed changes to the cap-and-trade program. We continue to monitor CARB rulemaking developments and evaluate any potential impacts on our operations.

On August 16, 2013, CARB held its fourth allowance auction, in which all of the approximate 13.9 million 2013 vintage allowances available for sale were sold at a clearing price of $12.22 per allowance. In addition, approximately 9.6 million vintage 2016 allowances were sold at a clearing price of $11.10 per allowance.

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We have participated in CARB's quarterly allowance auctions and will procure additional allowances as needed in future auctions and secondary markets. CARB's next quarterly allowance action is scheduled for November 19, 2013. We estimate the cost of CARB allowances required to operate our affected facilities during 2013 will be approximately $24 million.

On September 4, 2013, RGGI held its twenty-first auction, in which approximately 38.4 million allowances for the second control period were sold at a clearing price of $2.67 per allowance. RGGI's next quarterly auction is scheduled for December 4, 2013. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets.

We estimate the cost of RGGI allowances required to operate our affected facilities during 2013 will be approximately $7 million.

We expect that the cost of compliance for both RGGI and the California GHG program would be reflected in the power market and the actual impact to gross margin would be largely offset by an increase in revenue.

Climate Change Litigation. In October 2013, the U.S. Supreme Court granted petitions for review in a group of cases involving the EPA's GHG program. The Court will review the limited question of whether the EPA permissibly determined that its regulation of motor vehicle GHG emissions triggered permitting requirements under the Clean Air Act for stationary sources that emit GHGs. The Court is expected to issue a decision by mid-2014.

In July 2013, the D.C. Circuit Court of Appeals dismissed challenges by certain states and industry groups to EPA rules concerning incorporation of GHG requirements into Prevention of Significant Deterioration ("PSD") permit programs of state implementation plans. The court concluded that the petitioners lacked standing, finding that Clean Air Act section 165(a), which prohibits construction or modification without a PSD permit, is immediately self-executing whenever a pollutant becomes subject to regulation. Thus, any injury to petitioners was caused by the Act itself, and not the challenged EPA rules.

RISK MANAGEMENT DISCLOSURES

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

(amounts in millions)	As of and for the Nine Months Ended September 30, 2013	
Balance Sheet Risk Management Accounts		
Fair value of portfolio at December 31, 2012	$(50	)
Risk management losses recognized through the statement of operations in the period, net	(18	)
Contracts realized or otherwise settled during the period	8	
Changes in collateral/margin netting	—	
Fair value of portfolio at September 30, 2013	$(60	)

The net risk management liability of $60 million is the aggregate of the following line items on our unaudited condensed consolidated balance sheets: Current Assets—Assets from risk management activities, Other Assets—Assets from risk management activities, Current Liabilities—Liabilities from risk management activities and Other Liabilities—Liabilities from risk management activities.

Risk Management Asset and Liability Disclosures. The following table provides an assessment of net contract values by year as of September 30, 2013, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total		2013		2014		2015		2016		2017		Thereafter
Market quotations (1) (2)	$(61	)	$(21	)	$(12	)	$(15	)	$(11	)	$(5	)	$3
Prices based on models (2)	(7	)	—		(7	)	—		—		—		—
Total (3)	$(68	)	$(21	)	$(19	)	$(15	)	$(11	)	$(5	)	$3

(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 7—Fair Value Measurements for further discussion.

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(3) Excludes $7 million of broker margin and $1 million of collateral that has been netted against Risk Management liabilities on our consolidated balance sheet. Please read Note 6—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

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

- expectations and beliefs related to the AER Acquisition and satisfying closing conditions, including obtaining variance relief from the IPCB and the timing of such relief;
- anticipated benefits and expected synergies resulting from the AER Acquisition and beliefs associated with the integration of operations;
- lack of comparable financial data due to the application of fresh-start accounting;
- beliefs and assumptions relating to our liquidity, available borrowing capacity and capital resources, generally including the extent to which such liquidity could be affected by poor economic and financial market conditions or new regulations and any resulting impacts on financial institutions and other current and potential counterparties;
- limitations on our ability to utilize previously incurred federal net operating losses or alternative minimum tax credits;
- expectations regarding our compliance with the Credit Agreement, including collateral demands, interest expense, any applicable financial ratios and other payments;
- the timing and anticipated benefits to be achieved through our company-wide savings improvement programs, including our PRIDE initiative;
- efforts to identify opportunities to reduce congestion and improve busbar power prices;
- expectations regarding environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts and other laws and regulations to which we are, or could become, subject;
- beliefs, assumptions and projections regarding the demand for power, generation volumes and commodity pricing, including natural gas prices and the timing of a recovery in natural gas prices, if any;
- sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation thereof;
- beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale power generation market, including the anticipation of higher market pricing over the longer term;
- the effectiveness of our strategies to capture opportunities presented by changes in commodity prices and to manage our exposure to energy price volatility;
- beliefs and assumptions about weather and general economic conditions;
- projected operating or financial results, including anticipated cash flows from operations, revenues and profitability;
- our focus on safety and our ability to efficiently operate our assets so as to capture revenue generating opportunities and operating margins;
- beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the South Bay and Vermilion facilities;
- timing of the retirement of the Morro Bay facility and anticipated opportunities for redevelopment;
- beliefs and assumptions regarding approval by the CPUC of the SCE 2016 transaction for Moss Landing Units 6 & 7;

- ability to mitigate impacts associated with expiring RMR and/or capacity contracts;
- beliefs about the outcome of legal, administrative, legislative and regulatory matters, including the impact of final rules regarding derivatives to be issued by the CFTC under the Dodd-Frank Act; and
- expectations regarding performance standards and estimates regarding capital and maintenance expenditures.

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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 this Form 10-Q.

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.

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Item 3—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our Form 10-K for a discussion of our exposure to commodity price variability and other market risks related to our net non-trading derivative assets and liabilities, including foreign currency exchange rate risk. The following is a discussion of the more material of these risks and our relative exposures as of September 30, 2013.

Value at Risk (“VaR”). The following table sets forth the aggregate daily VaR of the mark-to-market portion of our risk management portfolio primarily associated with the Coal and Gas segments. The VaR calculation does not include market risks associated with the accrual portion of the risk management portfolio that is designated as “normal purchase, normal sale,” nor does it include expected future production from our generating assets. Please read “VaR” in our Form 10-K for a complete description of our valuation methodology. The decrease in the September 30, 2013 VaR was primarily due to decreased forward positions as compared to December 31, 2012.

Daily and Average VaR for Risk Management Portfolios

(amounts in millions)	September 30, 2013	December 31, 2012
One day VaR—95 percent confidence level	$2	$2
One day VaR—99 percent confidence level	$2	$3
Average VaR for the year-to-date period—95 percent confidence level	$3	$4

Credit Risk. The following table represents our credit exposure at September 30, 2013 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	$10	$—	$10
Utility and power generators	—	—	—
Commercial/industrial/end users	—	—	—
Total	$10	$—	$10

Interest Rate Risk

We are exposed to fluctuating interest rates related to our variable rate financial obligations, which consist of amounts outstanding under our Credit Agreement. We currently use interest rate swaps to mitigate this interest rate exposure. Our interest rate hedging instruments are recorded at their fair value. The related debt is not recorded at its fair value. As a result of our outstanding interest rate derivatives, we do not have any significant exposure to changes in LIBOR. The absolute notional amounts associated with our interest rate contracts were as follows at September 30, 2013 and December 31, 2012, respectively:

	September 30, 2013	December 31, 2012
Interest rate swaps (in millions of U.S. dollars) (1)	$796	$1,100
Fixed interest rate paid (percent)	3.15	2.22
Interest rate caps (in millions of U.S. dollars) (2)	$—	$1,400
Interest rate threshold (percent)	—	2.00

(1) The calculation period for $250 million of the interest rate swaps began June 30, 2013, and the calculation period for the remaining $546 million is scheduled to begin in the fourth quarter 2013.

(2) The $1,400 million interest rate caps were terminated in July 2013.

Item 4—CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of September 30, 2013.

Changes in Internal Controls Over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the quarter ended September 30, 2013.

DYNEGY INC.

PART II. OTHER INFORMATION

Item 1—LEGAL PROCEEDINGS

See Note 13—Commitments and Contingencies—Legal Proceedings to the accompanying unaudited condensed 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 and Form 10-Q for the quarters ended March 31, 2013 and June 30, 2013 for factors, risks and uncertainties that may affect future results.

Item 6—EXHIBITS

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

Exhibit Number	Description
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
†32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

** Filed herewith.

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

DYNEGY INC.

SIGNATURE

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

			DYNEGY INC.
Date:	November 7, 2013	By:	/s/ CLINT C. FREELAND Clint C. Freeland Executive Vice President and Chief Financial Officer