DYNEGY INC.
Form 10-Q
May 02, 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 March 31, 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, 99,999,196 shares outstanding as of April 23, 2013.

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DEFINITIONS

Unless the context indicates otherwise, throughout this report, the terms “Dynegy,” “the Company,” “we,” “us,” “our,” and “ou are used to refer to Dynegy Inc. and its direct and indirect subsidiaries. Discussions or areas of this report that apply only to Dynegy, Legacy Dynegy or DH are clearly noted in such sections or areas and specific defined terms may be introduced for use only in those sections or areas. Further, 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
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
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	U.S. Commodity Futures Trading Commission
CPUC	California Public Utility Commission
CRCG	Commodity Risk Control Group
CSAPR	Cross-State Air Pollution Rule
DCIH	Dynegy Coal Investments Holdings, LLC
DGIN	Dynegy Gas Investments, LLC
DH	Dynegy Holdings, LLC (formerly known as Dynegy Holdings Inc.)
DMG	Dynegy Midwest Generation, 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
EMT	Executive Management Team
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
ICC	Illinois Commerce Commission
IMA	In-market asset availability
IPH	Illinois Power Holdings, LLC
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LC	Letter of Credit

LIBOR	London Interbank Offered Rate

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MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	One million British thermal units
MW	Megawatts
MWh	Megawatt hour
NM	Not Meaningful
NOL	Net operating loss
NPDES	National Pollutant Discharge Elimination System
NYISO	New York Independent System Operator
NYSE	New York Stock Exchange
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PRIDE	Producing Results through Innovation by Dynegy Employees
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)

	March 31, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	$304	$348
Restricted cash	98	98
Accounts receivable	87	108
Accounts receivable, affiliates	1	1
Inventory	93	101
Assets from risk-management activities	36	13
Assets from risk-management activities, affiliates	3	4
Broker margin account	34	40
Intangible assets	223	271
Prepayments and other current assets	77	59
Total Current Assets	956	1,043
Property, Plant and Equipment	3,062	3,064
Accumulated depreciation	(74)	(42)
Property, Plant and Equipment, Net	2,988	3,022
Other Assets		
Restricted cash	224	237
Assets from risk-management activities	1	—
Intangible assets	51	71
Deferred income taxes	95	95
Other long-term assets	67	67
Total Assets	$4,382	$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)

	March 31, 2013	December 31, 2012
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$95	$112
Accounts payable, affiliates	1	1
Accrued interest	1	—
Deferred income taxes	95	95
Accrued liabilities and other current liabilities	75	85
Liabilities from risk-management activities	73	25
Current portion of long-term debt	29	29
Total Current Liabilities	369	347
Long-term debt	1,353	1,386
Other Liabilities		
Liabilities from risk-management activities	43	42
Other long-term liabilities	254	257
Total Liabilities	$2,019	$2,032
Commitments and Contingencies (Note 13)		
Stockholders' Equity		
Common Stock, $0.01 par value, 420,000,000 shares authorized and 99,999,196 shares issued and outstanding at March 31, 2013 and December 31, 2012, respectively	1	1
Additional paid-in capital	2,600	2,598
Accumulated other comprehensive loss, net of tax	11	11
Accumulated deficit	(249)	(107)
Total Stockholders' Equity	$2,363	$2,503
Total Liabilities and Stockholders' Equity	$4,382	$4,535

See the notes to condensed consolidated financial statements.

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

	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012
Revenues	$318	$268
Cost of sales	(284)	(180)
Gross margin, exclusive of depreciation shown separately below	34	88
Operating and maintenance expense, exclusive of depreciation shown separately below	(71)	(34)
Depreciation and amortization expense	(54)	(22)
Gain on sale of assets, net	1	—
General and administrative expense	(22)	(20)
Acquisition and integration costs	(3)	—
Operating income (loss)	(115)	12
Bankruptcy reorganization items, net	(1)	152
Interest expense	(28)	(31)
Impairment of Undertaking receivable, affiliate	—	(832)
Other income and expense, net	2	24
Loss from continuing operations before income taxes	(142)	(675)
Income tax benefit (Note 15)	—	6
Loss from continuing operations	(142)	(669)
Loss from discontinued operations, net of tax	—	(413)
Net loss	$(142)	$(1,082)
Loss Per Share (Note 17):		
Basic loss per share:		
Loss from continuing operations	$(1.42)	N/A
Loss from discontinued operations	—	N/A
Basic loss per share	$(1.42)	N/A
Diluted loss per share:		
Loss from continuing operations	$(1.42)	N/A
Loss from discontinued operations	—	N/A
Diluted loss per share	$(1.42)	N/A
Basic shares outstanding	100	N/A
Diluted shares outstanding	100	N/A

See the notes to condensed consolidated financial statements.

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

	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012
Net loss	$(142)	$(1,082)
Amortization of unrecognized prior service cost and actuarial loss, net of tax	—	(1)
Other comprehensive loss, net of tax	$—	$(1)
Total comprehensive loss	$(142)	$(1,083)

See the notes to condensed consolidated financial statements.

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

	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(142)	$(1,082)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation and amortization	50	24
Amortization of intangibles	63	11
Bankruptcy reorganization items, net	—	228
Impairment of Undertaking receivable, affiliate	—	832
Risk-management activities	38	(41)
Risk-management activities, affiliate	—	1
Gain on sale of assets, net	(1)	—
Deferred income taxes	—	(6)
Other	5	(1)
Changes in working capital:		
Accounts receivable	22	24
Inventory	8	(3)
Broker margin account	(8)	2
Prepayments and other current assets	(10)	(107)
Accounts payable and accrued liabilities	(26)	7
Affiliate transactions	(1)	(29)
Changes in non-current assets	(4)	(6)
Changes in non-current liabilities	(1)	1
Net cash used in operating activities	$(7)	$(145)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(20)	(9)
Proceeds from asset sales, net	1	—
Decrease in restricted cash	13	148
Net cash provided by (used in) investing activities	$(6)	$139
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payment of financing costs	(3)	—
Repayments of borrowings	(28)	(3)
Net cash used in financing activities	$(31)	$(3)
Net decrease in cash and cash equivalents	(44)	(9)
Cash and cash equivalents, beginning of period	348	398
Cash and cash equivalents, end of period	$304	$389

See the notes to condensed consolidated financial statements.

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2013 and 2012

EXPLANATORY NOTE

On September 30, 2012, pursuant to the terms of the Joint Chapter 11 Plan of Reorganization (the "Plan") for Dynegy Holdings, LLC ("DH") and Dynegy Inc. ("Dynegy"), DH merged with and into Dynegy, with Dynegy continuing as the surviving legal entity (the "Merger"). As described below in Note 1—Basis of Presentation and Organization, the accounting treatment of the Merger was reflected as a recapitalization of DH and, similar to a reverse merger, DH was 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.

On September 10, 2012, the Bankruptcy Court (as defined and discussed below in Note 4—Chapter 11 Cases) entered an order confirming 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. Accordingly, the results of operations of the DNE Debtor Entities are presented in discontinued operations for all periods presented.

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."

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 and amortization 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 (the "DMG Transfer"). Therefore, the results of our Coal segment are not included in our consolidated results as of, and for the three months ended March 31, 2012. On June 5, 2012, DH reacquired Coal Holdco (including its subsidiary, DMG) from Legacy Dynegy (the "DMG Acquisition"). Please read Note 3—Acquisitions—DMG Acquisition for further discussion.

Merger. On September 30, 2012, pursuant to the terms of the Plan, DH merged with and into Legacy Dynegy, with Legacy Dynegy continuing as the surviving legal entity in 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 Merger was accounted for in a manner similar to a reverse merger, whereby DH is the surviving accounting entity for financial reporting purposes.

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2013 and 2012

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 statement of operations for the three months ended March 31, 2012.

Fresh-Start Accounting. On the Plan Effective Date, we applied "fresh-start accounting." Fresh-start accounting requires 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. Under the provisions of fresh-start accounting, a new entity has been created for financial reporting purposes. 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 Principles 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 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. 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.

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 interest of Ameren Energy Resources Company, LLC ("AER") (or, following a pre-closing reorganization contemplated by Ameren, a successor thereto) for no cash consideration (the "AER Acquisition"). AER and its subsidiaries consist 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") and (iii) Ameren Energy Marketing Company ("AEM"). We have 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”). Prior to signing the AER Transaction Agreement, 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

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2013 and 2012

put option agreement (the “Put Option Agreement”), dated as of March 28, 2012, 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”). New appraisals will be obtained for the Put Assets prior to closing, and if the average value of the appraisals exceeds $133 million, any excess amount will be remitted to Genco. Further, in the event Ameren sells the Put Assets within two years of closing, Ameren will pay to Genco any after-tax proceeds in excess of $133 million, or the higher appraised value, if applicable. The minimum amount of $133 million is based on an average of three appraisals obtained in October 2012. The amount may increase as a result of new appraisals, but can not be reduced.

In connection with the transaction, Ameren will retain certain historical obligations of AER and its subsidiaries, including certain historical environmental and tax liabilities. Genco's approximately $825 million 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.

In connection with the transaction, Ameren is required at closing to ensure that a minimum of $93 million of cash is available at AER and its subsidiaries of which $70 million will be held at Genco plus the proceeds of the Put Transaction described above.

The AER Transaction Agreement includes customary representations, warranties and covenants by the parties. The closing of the transaction is expected to occur during the fourth quarter of 2013 and is subject to customary conditions, including (i) consummation of the Put Transaction under the Put Option Agreement; (ii) approval of FERC under Section 203 of the Federal Power Act, as amended (“FERC Approval”); (iii) approval of certain license transfers by the Federal Communications Commission; (iv) approval by the Illinois Pollution Control Board of the transfer to IPH of AER's air variance, which granted to AER a temporary exemption for the coal plants of its subsidiaries from certain air pollution limitations under Illinois law; (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 customary conditions. 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 (subject to extension to 13 months in certain circumstances, if necessary in order to obtain FERC approval).

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, we entered into the Limited Guaranty, capped at $25 million in favor of Ameren, pursuant to which we will guaranty 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.

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.

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DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2013 and 2012

Pro Forma Results. The unaudited pro forma financial results for the three months ended March 31, 2012 show the effect of the DMG Acquisition as if the acquisition had occurred as of January 1, 2012.

(amounts in millions)	Predecessor Three Months Ended March 31, 2012
Revenues	$445
Loss from continuing operations	$(689)
Loss from discontinued operations	$(413)
Net loss	$(1,102)

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 and continue to operate their businesses as “debtors-in-possession” (the “DNE Bankruptcy Cases”). As a result, we deconsolidated the DNE Debtor Entities on the Plan Effective Date and have reported their results of operations as discontinued operations for all periods presented. Please read Note 5—Discontinued Operations and Note 10—Variable Interest Entities for further discussion.

For the three months ended and as of March 31, 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 months ended March 31, 2012 are set forth below (amounts in millions):

Condensed Combined Statement of Operations of the Debtor Entities
For the Three Months Ended March 31, 2012

Revenues	$—
Cost of sales	—
Operating expenses	—
General and administrative expenses	(2)
Operating loss	(2)
Bankruptcy reorganization items, net	152
Equity losses	(17)
Impairment of Undertaking receivable, affiliate	(832)
Other income and expense, net	24
Income tax benefit	6
Loss from continuing operations	(669)
Loss from discontinued operations	(413)
Net loss	$(1,082)

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DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
For the Interim Periods Ended March 31, 2013 and 2012

Condensed Combined Statement of Cash Flows of the Debtor Entities
For the Three Months Ended March 31, 2012

Net cash used in:	
Operating activities	$(12)
Investing activities	—
Financing activities	—
Net decrease in cash and cash equivalents	(12)
Cash and cash equivalents, beginning of period	33
Cash and cash equivalents, end of period	$21

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 consolidation.

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 $71 million for the three months ended March 31, 2012.

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.

The table below lists the significant items within this category for the three months ended March 31, 2012 (amounts in millions).

	Three Months Ended March 31, 2012
Adjustments of estimated allowable claims:	
DNE Leases (1)	$(395)
Subordinated notes (2)	161
Write-off of note payable, affiliate (3)	10
Other	(4)
Total adjustments for estimated allowable claims	(228)
Professional fees (4)	(19)
Total Bankruptcy reorganization items, net	(247)
Bankruptcy reorganization items, net included in discontinued operations	399
Total Bankruptcy reorganization items, net in continuing operations	$152

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(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.

(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 a Note payable, affiliate would be made. Therefore, the estimated amount was reduced to zero.

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

DYNEGY INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
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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 has 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 January 23, 2013, the Bankruptcy Court approved the DNE Disclosure Statement. On March 12, 2013, the Bankruptcy Court approved the Plan of Liquidation for the DNE Debtor Entities. On April 30, 2013, we completed the sale of the Roseton facility. The Danskammer facility sale is expected to close upon the satisfaction of certain closing conditions and the receipt of any necessary regulatory approvals. If the Danskammer facility sale is not successful, certain of the DNE Debtor Entities may be required to liquidate their remaining assets or convert the DNE Chapter 11 Cases to Chapter 7 liquidation under the Bankruptcy Code. 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. The results of operations of DNE are reported as discontinued operations for all periods presented.
Summary. There were no operating results reported as discontinued operations for the three months ended March 31, 2013. The amounts in the table below reflect the operating results of the businesses reported as discontinued operations for the three months ended March 31, 2012:

(amounts in millions)	Predecessor Three Months Ended March 31, 2012
Revenues	$ 7
Income (loss) from operations before taxes	$ (413)
Income (loss) from operations after taxes	$ (413)

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 two- 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. We elect not to designate any of our derivatives as accounting hedges. As of March 31, 2013, our commodity derivatives were comprised of both purchases and sales of commodities. As of March 31, 2013, we had net purchases and sales of derivative contracts outstanding in the following quantities:

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Contract Type	Hedge Designation	Quantity	Unit of Measure	Net Fair Value
(amounts in millions)				
Commodity contracts:				
Electric energy (1)	Not designated	(31)	MWh	$(80)
Natural gas (1)	Not designated	130	MMBtu	$27
Heat rate derivatives	Not designated	(1)/10	MWh/MMBtu	$3
Interest rate contracts:				
Interest rate swaps	Not designated	1,100	Dollars	$(46)
Interest rate caps	Not designated	1,400	Dollars	$—
Common stock warrants	Not designated	16	Warrants	$(20)

(1) 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 sheet presents 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 March 31, 2013 and the consolidated balance sheet as of December 31, 2012 segregated by type of contract segregated by assets and liabilities.

		March 31, 2013			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value (1)	Contract Netting	Collateral or Margin Received or Paid	Net Fair Value
(amounts in millions)					
Derivative assets:					
Commodity contracts	Assets from risk management activities	$124	$(87)	$—	$37
Commodity contracts, affiliates	Assets from risk management activities, affiliates	3	—	—	3
Total derivative assets		$127	$(87)	$—	$40
Derivative liabilities:					
Commodity contracts	Liabilities from risk management activities	$(177)	$87	$20	$(70)
Interest rate contracts	Liabilities from risk management activities	(46)	—	—	(46)
Common stock warrants	Other long-term liabilities	(20)	—	—	(20)
Total derivative liabilities		$(243)	$87	$20	$(136)

Total derivatives	$(116)	$—	$20	$(96)

(1) As of and during the three months ended March 31, 2013, there were no gross amounts available to be offset that were not offset in our unaudited condensed consolidated balance sheet.

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		December 31, 2012			
			Gross amounts offset in the balance sheet		
Contract Type	Balance Sheet Location	Gross Fair Value (1)	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)

(1) As of and during the year ended December 31, 2012, there were no gross amounts available to be offset that were not offset in our consolidated balance sheet.

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

	March 31, 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	$51	$17	$44	$4
Prepayments and other current assets	$18	$3	$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 months ended March 31, 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 months ended March 31, 2013 and 2012, our Revenues included unrealized mark-to-market losses related to this activity of approximately $38 million and $43 million, respectively.

The realized and unrealized impact of derivative financial instruments on our unaudited condensed consolidated statements of operations for the three months ended March 31, 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.

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Derivatives Not Designated as Hedges	Location of Gain (Loss) Recognized in Income on Derivatives	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012
(amounts in millions)			
Commodity contracts	Revenues	$(34)	$8
Commodity contracts, affiliates	Revenues	$(2)	$(6)
Interest rate contracts	Interest Expense	$—	$3

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 March 31, 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 March 31, 2013			
(amounts in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Assets from commodity risk management activities:				
Electricity derivatives	$—	$47	$12	$59
Natural gas derivatives	—	65	—	65
Heat rate derivatives	—	—	3	3
Total assets from commodity risk management activities	$—	$112	$15	$127
Liabilities:				.
Liabilities from commodity risk management activities:				
Electricity derivatives	$—	$(127)	$(12)	$(139)
Natural gas derivatives	—	(38)	—	(38)
Total liabilities from commodity risk management activities	—	(165)	(12)	(177)
Liabilities from interest rate contracts	—	(46)	—	(46)
Liabilities from outstanding common stock warrants	(20)	—	—	(20)
Total liabilities	$(20)	$(211)	$(12)	$(243)

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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 contracts classified within Level 3 are primarily financial swaps executed in illiquid trading locations, capacity contracts, heat rate derivatives and FTRs. The curves used to generate the fair value of the financial swaps are based on basis adjustments applied to forward curves for liquid trading points, while the curves for the capacity deals are based upon auction results in the marketplace, which are infrequently executed. Additionally, FTRs are classified within the electricity contracts, which are also an illiquid product. The forward market price of FTRs is derived using historical congestion patterns within the marketplace. 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, estimates of forward congestion power price spreads and assumptions of illiquid power location pricing basis to liquid locations. These assumptions 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. A 10 percent change in pricing inputs and changes in volatilities and correlation factors would result in less than a $1 million change in our Level 3 fair value. 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 March 31, 2013		
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Total

Balance at December 31, 2012	$5	$2	$7
Total gains included in earnings	—	1	1
Settlements (1)	(5)	—	(5)
Balance at March 31, 2013	$—	$3	$3
Unrealized gains relating to instruments held as of March 31, 2013	$—	$1	$1

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

	Predecessor			
	Three Months Ended March 31, 2012			
(amounts in millions)	Electricity Derivatives	Heat Rate Derivatives	Interest Rate Swaps	Total
Balance at December 31, 2011	$20	$(17)	$(6)	$(3)
Total gains (losses) included in earnings, net of affiliates	2	2	(3)	1
Settlements, net of affiliates (1)	—	4	—	4
Balance at March 31, 2012	$22	$(11)	$(9)	$2
Unrealized losses relating to instruments (net of affiliates) held as of March 31, 2012	$(1)	$—	$(3)	$(4)

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

Gains and losses (realized and unrealized) for Level 3 recurring items are included in Revenues and Interest expense, net 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 months ended March 31, 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 months ended March 31, 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 investments, short-term investments 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 March 31, 2013 and December 31, 2012, respectively.

	March 31, 2013		December 31, 2012	
(amounts in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Interest rate derivatives not designated as accounting hedges (1)	$(46)	$(46)	$(46)	$(46)
Commodity-based derivative contracts not designated as accounting hedges (1)	$(50)	$(50)	$(12)	$(12)
DPC Credit Agreement due 2016 (2)	$(875)	$(867)	$(880)	$(874)
DMG Credit Agreement due 2016 (3)	$(507)	$(510)	$(535)	$(537)
Common stock warrants	$(20)	$(20)	$(20)	$(20)

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

(2) Carrying amount includes unamortized premiums of $40 million and $43 million at March 31, 2013 and December 31, 2012, respectively. The fair value of the DPC Credit Agreement is classified within Level 2 of the fair value hierarchy. Please read Note 19—Subsequent Events for further discussion.

(3) Carrying amount includes unamortized premiums of $16 million and $18 million as of March 31, 2013 and December 31, 2012, respectively. The fair value of the DMG Credit Agreement is classified within Level 2 of the fair value hierarchy. Please read Note 19—Subsequent Events for further discussion.

Note 8—Accumulated Other Comprehensive Income

Changes in accumulated other comprehensive income, net of tax, by component for the three months ended March 31, 2013 and 2012 are as follows:

(amounts in millions)	Successor Three Months Ended March 31, 2013 Defined Benefit Pension Items	Predecessor Three Months Ended March 31, 2012 Defined Benefit Pension Items
Beginning of period	$11	$1
Current period other comprehensive income:		
Other comprehensive income before reclassifications	—	—
Amounts reclassified from accumulated other comprehensive income	—	(1)
Net current period other comprehensive income	$—	$(1)
End of period	$11	$—

Note 9—Inventory

A summary of our inventories is as follows:

(amounts in millions)	March 31, 2013	December 31, 2012
Materials and supplies	$45	$46
Coal	37	52
Fuel oil	3	3
Emissions allowances	8	—
Total	$93	$101

Note 10—Variable Interest Entities

DNE. Effective October 1, 2012, the DNE Debtor Entities were deconsolidated. As of March 31, 2013 and December 31, 2012, we had less than $1 million in net receivables 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 exposure to loss 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. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K for further discussion. Also, please read Note 14—Related Party Transactions for a discussion of the Service Agreements.

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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
December 31, 2012	$ 202	$ 115	$ (22)	$ 295
Amortization	(34)	(31)	2	(63)
March 31, 2013 (1)	$ 168	$ 84	$ (20)	$ 232

(1) The total amount of $232 million consists of $223 million in short-term Intangible assets, $51 million in long-term Intangible assets, $16 million in Accrued liabilities and other current liabilities, and $26 million in Other long-term liabilities on our unaudited condensed consolidated balance sheet.

Note 12—Debt

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

(amounts in millions)	March 31, 2013 Carrying Amount	March 31, 2013 Fair Value	December 31, 2012 Carrying Amount	December 31, 2012 Fair Value
DPC Credit Agreement, due 2016 (1)	$ 835	$ 867	$ 837	$ 874
DMG Credit Agreement, due 2016 (1) (2)	491	510	517	537
	1,326		1,354	
Unamortized premium on debt, net	56		61	
	1,382		1,415	
Less: Amounts due within one year, including unamortized premium on debt, net of $16 million and $15 million, respectively	29		29	
Total Long-term debt	$ 1,353		$ 1,386	

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

(2) On March 28, 2013, we repaid $25 million of the outstanding balance of the DMG Credit Agreement at par. In connection with the repayment, we recorded a gain of approximately $1 million related to the accelerated amortization of the premium on the debt which is included in Interest expense on our unaudited condensed consolidated statements of operations.

On April 23, 2013, we entered into the Credit Agreement. Please read Note 19—Subsequent Events for further discussion.

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 will be used for the ongoing working capital requirements and general corporate purposes of DPC and its subsidiaries.

The DPC Revolving Credit Agreement creates 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 and which commitment amount may be adjusted pursuant to the terms thereof. Amounts borrowed under the DPC Revolving Credit Agreement that are repaid or prepaid may be re-borrowed. The DPC Revolving Credit Agreement will mature on January 15, 2014 (the “Maturity Date”) and the unpaid outstanding principal amount of each revolving loan thereunder will be repaid on or prior to the Maturity Date. DPC may reduce the aggregate commitments outstanding under the DPC Revolving Credit Facility without premium or penalty. DPC must pay a commitment fee at a rate of 0.50 percent per year on the average daily unused

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amount of the commitment under the DPC Revolving Credit Facility. As of March 31, 2013, there have been no borrowings on the DPC Revolving Credit Agreement.

The DPC Revolving Credit Agreement bears interest, at DPC's option, at either (a) 3.25 percent per annum plus the Adjusted LIBOR Rate, with respect to any Eurodollar Revolving Loan or (b) 2.25 percent per annum plus the Alternate Base Rate, with respect to any ABR Revolving Loan. DPC may elect from time to time to convert all or a portion of the revolving loans from an ABR Borrowing into a Eurodollar Borrowing or vice versa. The DPC Revolving Credit Agreement requires a mandatory prepayment only in the event the aggregate revolving loans exceed the aggregate revolving credit commitments.

On April 23, 2013, we entered into the Credit Agreement, at which time the DPC Revolving Credit Agreement was terminated. Please read Note 19—Subsequent Events for further discussion.

Restricted Cash

The following table depicts our restricted cash:

(amounts in millions)	March 31, 2013	December 31, 2012
DPC LC facilities (1)	$210	$220
DPC Collateral Posting Account (2)	67	63
DMG LC facility (3)	12	14
DMG Collateral Posting Account (2)	4	8
Corporate LC facilities (1)	27	27
Other (4)	2	3
Total restricted cash	$322	$335

(1) Includes cash posted to support the respective letter of credit reimbursement and collateral agreement.
(2) Amounts are restricted and may be used for future collateral posting requirements or released per the terms of the applicable credit agreement.
(3) Includes cash posted to support the letter of credit reimbursement and collateral agreements under the DMG LC facility. Please read "Letter of Credit Facilities" in our Form 10-K for further discussion.
(4) Includes cash posted to support a letter of credit and collateral for the corporate card program.

The DMG and DPC Credit Agreements were repaid in April 2013. Please read Note 19—Subsequent Events for further discussion.

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 each 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

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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.

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 timeframe. 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. We are assessing next steps in the appellate process.

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. 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 the 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.

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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 March 31, 2013.

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 $14 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 response, we submitted to the Illinois EPA a proposed compliance commitment agreement for each facility. For Vermilion, we proposed to implement the previously submitted corrective action plans and, for Baldwin, we proposed to perform additional studies of hydrogeologic conditions and apply for a groundwater management zone in preparation for submittal, as necessary, of a corrective action plan. In October 2012, the Illinois EPA notified us that it would not issue proposed compliance commitment agreements for Vermilion and Baldwin. 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 response to further discussions with the Illinois EPA, in March 2013 we submitted proposals to evaluate options concerning our proposed corrective action plans at Vermilion and to perform further hydrogeological 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.

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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 Illinois Pollution Control Board 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. We dispute the allegations and will defend the permit vigorously. The permit remains in effect during the appeal. The outcome of the appeal 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, Southern California Edison ("SCE") notified Dynegy Morro Bay, LLC and Dynegy Moss Landing, LLC that it was terminating certain energy and capacity contracts with those entities. The validity of the purported terminations and subsequent actions by SCE are being disputed by Dynegy. We are vigorously pursuing all remedies and amounts due to us under these contracts.

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.
Indemnities
The indemnifications discussed below were settled or discharged pursuant to the Plan and the Confirmation Order with respect to Dynegy.
LS Power Indemnities. In connection with the LS Power Transactions we agreed in the purchase and sale agreement to indemnify LS Power against claims regarding any breaches in our representations and warranties and certain other potential liabilities. Even though Dynegy was discharged from any claims pursuant to the Plan and Confirmation Order, Dynegy Power Generation Inc., DPC, DMG and DYPM remain jointly and severally liable for any indemnification claims (the “LS Indemnity

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Entities”). Claims for indemnification shall survive until twelve months subsequent to closing with exceptions for tax claims, which shall survive for the applicable statute of limitations plus 30 days, and certain other representations and potential liabilities, which shall survive indefinitely. The indemnifications provided to LS Power are limited to $1.3 billion in total; however, several categories of indemnifications are not available to LS Power until the liabilities incurred in the aggregate are equal to or exceed $15 million and are capped at a maximum of $100 million. Further, the purchase and sale agreement provides in part that the LS Indemnity Entities may not reduce or avoid liability for a valid claim based on a claim of contribution. In addition to the above indemnities related to the LS Power Transactions, the LS Indemnity Entities may be required to indemnify LS Power against claims related to the Riverside/Foothills Project for certain aspects of the project. Namely, LS Power has been indemnified for any disputes that arise as to ownership, transfer of bonds related to the project, and any failure by us to obtain approval for the transfer of the payment in-lieu of taxes program already in place. The indemnities related solely to the Riverside/Foothills Project are capped at a maximum of $180 million and extend until the earlier of the expiration of the tax agreement or December 26, 2026. At this time, we are not required to accrue a liability for and no significant expenses have been incurred under these indemnities.

Illinois Power Company Indemnities. We have indemnified third parties against losses resulting from possible adverse regulatory actions taken by the ICC that could prevent Illinois Power Company from recovering costs incurred in connection with purchased natural gas and investments in specified items. Even though Dynegy was discharged from any claims pursuant to the Plan and Confirmation Order, Illinova Corporation (“Illinova”) remains liable for any indemnification claims. Although there is no absolute limitation on Illinova’s liability under this indemnity, the amount of the indemnity is limited to 50 percent of any such losses. We have in the past made certain payments in respect of these indemnities following regulatory action by the ICC, and have established reserves for further potential indemnity claims.

Other Indemnities. 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 and the sale of our midstream business (“DMSLP”). 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. As of March 31, 2013, no claims have been made against and we have not recorded a liability for these indemnities.

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 March 31, 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 is through September 2013 while 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 agreements are approximately $14 million and $11 million for the years 2013 and 2014, respectively. To date, the subsidiary of Transammonia Inc. has complied with the terms of the sub-charter agreements.

Note 14—Related Party Transactions

The following tables summarize the Accounts receivable, affiliates, and Accounts payable, affiliates, on our unaudited condensed consolidated balance sheets as of March 31, 2013 and December 31, 2012; and cash received (paid) for the three months ended March 31, 2013 which is related to various agreements with Dynegy Inc., as discussed below.

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	Successor			Predecessor
	March 31, 2013		Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
(amounts in millions)	Accounts Receivable, Affiliates	Accounts Payable, Affiliates	Cash Received	Cash Received
Service Agreements	$ 1	$ 1	$ 1	$ 11
EMA Agreements	—	—	—	1
Total	$ 1	$ 1	$ 1	$ 12

	December 31, 2012	
(amounts in millions)	Accounts Receivable, Affiliates	Accounts Payable, Affiliates
Service Agreements	$ 1	$ 1
EMA Agreements	—	—
Total	$ 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 during the three months ended March 31, 2012. 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 statement of operations includes $2 million of power purchased from our unconsolidated affiliate, which is reflected in Revenues for the three months ended March 31, 2013.

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. Our unaudited condensed consolidated statement of operations includes $136 million of power purchased from affiliates, which is reflected in Revenues, and $55 million of coal sold to affiliates, which is reflected in Costs of sales, for the three months ended March 31, 2012. 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. As a result of the DMG Acquisition, transactions executed under the Energy Management Agreement are not considered related party transactions subsequent to June 5, 2012 because they eliminate in consolidation.

DMG Transfer and Undertaking Agreement. During the three months ended March 31, 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 statement of operations. In addition, we did not receive any payments from Legacy Dynegy during the three months ended March 31, 2012 related to 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.

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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.

(amounts in millions, except rates)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012
Income tax benefit	$—	$6
Effective tax rate	— %	1 %

For the three months ended March 31, 2013, the difference between the effective rate of zero 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 March 31, 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 March 31, 2012, the difference between the effective rates of 1 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 March 31, 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.

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 retirement 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. The transfer of the plans was recorded as part of the DMG Transfer as a common control transaction.

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. As a result of the Merger on September 30, 2012, we became the sponsor of these plans.

Components of Net Periodic Benefit Cost. The components of net periodic benefit cost for the three months ended March 31, 2013 were:

	Three Months Ended March 31, 2013	
(amounts in millions)	Pension Benefits	Other Benefits
Service cost benefits earned during period	$2	$—
Interest cost on projected benefit obligation	3	1
Expected return on plan assets	(4)	—
Total net periodic benefit cost	$1	$1

There were no such net periodic benefit costs related to the Predecessor for the three months ended March 31, 2012, as the costs related to these plans were included in Legacy Dynegy.

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Contributions. During the three months ended March 31, 2013, we made $2 million in voluntary contributions to our pension plans and none to our other post-retirement benefit plans. We are not required to make contributions to our pension plans and other postretirement benefit plans during 2013; however, we may elect to make voluntary contributions.

Note 17—Loss Per Share

The reconciliation of basic loss per share from continuing operations to diluted loss per share from continuing operations of our common stock outstanding during the period is shown in the following table. Basic loss per share represents the amount of losses for the period available to each share of our common stock outstanding during the period. Diluted loss per share represents the amount of 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 period ended March 31, 2012.

(in millions, except per share amounts)	Three Months Ended March 31, 2013
Loss from continuing operations for basic and diluted loss per share	$(142)
Basic weighted-average shares	100
Effect of dilutive securities—stock options and restricted stock	—
Diluted weighted-average shares	100
Loss per share from continuing operations:	
Basic	$(1.42)
Diluted (1)	$(1.42)

(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 period ended March 31, 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 have 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; therefore, the results of our Coal segment are not included for the three months ended March 31, 2012. Additionally, on June 5, 2012, we reacquired the Coal segment through the DMG Acquisition; therefore, the results of our Coal segment are included for the three months ended March 31, 2013. 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 months ended March 31, 2013 and 2012 is presented below:

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Segment Data as of and for the Three Months Ended March 31, 2013
(amounts in millions)

	Successor			
	Coal	Gas	Other and Eliminations	Total
Unaffiliated revenues:				
Domestic	$87	$231	$—	$318
Total revenues	$87	$231	$—	$318
Depreciation and amortization	$(13)	$(40)	$(1)	$(54)
General and administrative expense	—	—	(22)	(22)
Operating loss	$(80)	$(8)	$(27)	$(115)
Bankruptcy reorganization items, net	—	—	(1)	(1)
Interest expense				(28)
Other items, net	—	1	1	2
Loss before income taxes				(142)
Income tax benefit				—
Net loss				$(142)
Identifiable assets (domestic)	$1,234	$2,716	$432	$4,382
Capital expenditures	$(12)	$(8)	$—	$(20)

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Segment Data as of and for the Three Months Ended March 31, 2012
(amounts in millions)

	Predecessor		
	Gas	Other and Eliminations	Total
Unaffiliated revenues:			
Domestic	$268	$—	$268
Total revenues	$268	$—	$268
Depreciation and amortization	$(20)	$(2)	$(22)
General and administrative expense	—	(20)	(20)
Operating income (loss)	$34	$(22)	$12
Bankruptcy reorganization items, net	—	152	152
Interest expense			(31)
Impairment of Undertaking receivable, affiliate	—	(832)	(832)
Other items, net	—	24	24
Loss from continuing operations before income taxes			(675)
Income tax benefit			6
Loss from continuing operations			(669)
Loss from discontinued operations, net of tax			(413)
Net loss			$(1,082)
Identifiable assets (domestic)	$6,808	$713	$7,521
Capital expenditures	$(8)	$(1)	$(9)

Note 19—Subsequent Events

Credit Agreement

On April 23, 2013, Dynegy (the “Borrower”) entered into an approximate $1.8 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 steps down based on a Senior Secured Leverage Ratio (as defined in the Credit Agreement) and matures April 23, 2018.

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) 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 will be 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 was removed.

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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 debt, the outstanding debt used in this calculation is limited to the amounts outstanding under the Tranche B-2 Term Loan.

In connection with the repayment of the DPC and DMG Credit Agreements, we expect to record a charge of approximately $7 million, which consists of a prepayment penalty of approximately $59 million and $3 million in accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility, partially offset by the accelerated amortization of the remaining premium related to the DPC and DMG Credit Agreements of approximately $55 million.

DYNEGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS
For the Interim Periods Ended March 31, 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 the consolidated financial statements for all periods presented.

AER Transaction Agreement. On March 14, 2013, IPH entered into the AER Transaction Agreement, whereby IPH will acquire AER 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. The closing is expected to occur in the fourth quarter 2013. Please read Note 3—Acquisitions—AER Transaction Agreement for further discussion.

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 in the Merger. Immediately prior to the Merger, Legacy Dynegy had no substantive operations, and our operations were primarily conducted through subsidiaries of DH. Further, as a result of the DH Chapter 11 Cases (as defined below) 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 Legacy Dynegy's consolidated financial statements as of November 7, 2011. As a result of these factors, the Merger was accounted for in a manner similar to a reverse merger, whereby DH was the surviving accounting entity for financial reporting purposes.

DMG Transfer/Acquisition. On September 1, 2011, we completed the DMG Transfer; therefore, the results of our Coal segment are not included for the three months ended March 31, 2012. Additionally, on June 5, 2012, we reacquired the Coal segment through the DMG Acquisition; therefore, the results of our Coal segment are included for the three months ended March 31, 2013.

Chapter 11 Cases. On November 7, 2011, the DH Debtor Entities filed the DH Chapter 11 Cases. On July 6, 2012, Legacy Dynegy commenced the Dynegy Chapter 11 Case. On July 12, 2012, Legacy Dynegy and DH, as co-plan proponents, filed the Plan for Legacy Dynegy and DH and the related disclosure statement with the Bankruptcy Court. On September 10, 2012, the Bankruptcy Court entered an order confirming the Plan. As discussed above, on September 30, 2012, pursuant to the terms of the Plan, DH and Legacy Dynegy consummated the Merger, with Dynegy continuing as the surviving legal entity. On the Plan Effective Date, we consummated our reorganization under Chapter 11 pursuant to the Plan and Dynegy exited bankruptcy. At such time, Dynegy's issued common stock and Warrants were listed on the NYSE and director nominees selected by certain creditor parties, as determined by the Plan and confirmed by the Bankruptcy Court, were appointed as the new Board of Directors.

For financial reporting purposes, close of business on October 1, 2012, represents the date of our emergence from 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.

The DNE Debtor Entities remain in Chapter 11 bankruptcy and continue to operate their businesses as "debtors-in-possession." The Bankruptcy Court has approved the Facilities Sale Transactions for a combined cash purchase price of $23

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million and the assumption of certain liabilities. On April 30, 2013, we completed the sale of the Roseton facility. The Danskammer facility sale is expected to close upon the satisfaction of certain closing conditions and the receipt of any necessary regulatory approvals. Please read Note 3—Emergence from Bankruptcy and Fresh-Start Accounting in our Form 10-K and Note 5—Discontinued Operations for further discussion.

LIQUIDITY AND CAPITAL RESOURCES

Overview

In this section, we describe our liquidity and capital requirements including our sources and uses of liquidity and capital resources. Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, 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 an approximate $1.8 billion Credit Agreement that 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. The Term Facilities bear interest at LIBOR plus 3.00 percent per annum with a one percent floor and mature April 23, 2020. The Revolving Facility bears interest, initially, at LIBOR plus 2.75 percent, with steps down based on a Senior Secured Leverage Ratio (as defined in the Credit Agreement) and matures April 23, 2018.

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, all of the restricted cash on hand was released. None of the borrowings under the Credit Agreement will be classified as restricted cash. Please read Note 19—Subsequent Events for further discussion.

The new Credit Agreement improves our capital structure efficiency and flexibility, increases liquidity and reduces administrative costs.

Current Liquidity. The following tables summarize our liquidity position at April 23, 2013 and March 31, 2013.

	April 23, 2013
(amounts in millions)	Total (1)
Revolver capacity	$475
Less: Outstanding letters of credit	(180)
Revolver availability	295
Cash and cash equivalents	420
Total available liquidity	$715

	March 31, 2013			
(amounts in millions)	DPC	DMG	Other (2)	Total
LC capacity, inclusive of required reserves (3)	$210	$12	$28	$250
Less: Required reserves (3)	(6)	—	(1)	(7)
Less: Outstanding letters of credit	(202)	(11)	(26)	(239)
LC availability	2	1	1	4
DPC Revolving Credit Agreement availability	150	—	—	150
Cash and cash equivalents	23	7	274	304
Collateral Posting Account (4)	67	4	—	71

Total available liquidity (5)	$242	$12	$275	$529

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(1) On April 23, 2013, Dynegy entered into the Credit Agreement and eliminated the ring-fenced structure that was required under the DMG and DPC Credit Agreements; therefore, liquidity information is only being provided on an aggregate basis.

(2) Other cash consists of $1 million at Dynegy Gas Holdco, LLC, $5 million at Dynegy Administrative Services Company and $268 million at Dynegy Inc. as of March 31, 2013.

(3) The LC facilities were collateralized with cash proceeds received under the DPC and DMG Credit Agreements. The amount of the LC availability plus any unused required reserves of 3 percent of the unused capacity, could have been withdrawn from the LC facilities with three days written notice for unrestricted use in the operations of the applicable entity. LC capacity as of March 31, 2013 reflects a reduction in capacity for DMG and DPC following the requested release of unused cash collateral from restricted cash.

(4) The Collateral Posting Account included in the above liquidity tables was restricted per the DMG Credit Agreement and the DPC Credit Agreement.

(5) Does not reflect our ability to use the first lien structure as described in Operating Activities—“Collateral Postings.”

Operating Activities

Historical Operating Cash Flows. Our cash flow used by operations totaled $7 million for the three months ended March 31, 2013. During the period, our power generation business provided cash of $37 million primarily due to positive earnings for the period, partially offset by $34 million in negative changes in working capital, which includes $9 million of increased collateral postings to satisfy our counterparty collateral demands. Corporate and other operations used cash of approximately $24 million primarily due to payments to advisors, employee related payments and other general and administrative expenses, partially offset by $14 million in positive changes in working capital.

Our cash flow used in operations totaled $145 million for the three months ended March 31, 2012. During the period, our power generation business used cash of $122 million from the operation of our power generation facilities primarily due to increased collateral postings to satisfy our counterparty collateral demands (which was partially offset by a return of restricted cash as discussed below), interest payments on the DPC Credit Agreement and restructuring costs. Corporate and other operations included a use of approximately $23 million in cash primarily due to general and administrative expenses.

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, our ability to achieve the cost savings contemplated in our PRIDE improvement programs and our ability to capture value associated with commodity price volatility.

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. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The following table summarizes our collateral postings to third parties by legal entity at April 23, 2013, March 31, 2013 and December 31, 2012:

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(amounts in millions)	April 23, 2013	March 31, 2013	December 31, 2012
Dynegy Power, LLC:			
Cash (1)	$—	$43	$41
Letters of credit	—	202	212
Total DPC	$—	$245	$253
Dynegy Midwest Generation, LLC:			
Cash (1)	$—	$27	$22
Letters of credit	—	11	13
Total DMG	$—	$38	$35
Dynegy, Inc.:			
Cash	$162	$1	$1
Letters of credit	180	26	27
Total	$342	$27	$28
Total	$342	$310	$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 March 31, 2013 and December 31, 2012, $20 million and $8 million of cash posted as collateral was included in 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 increased from March 31, 2013 to April 23, 2013 primarily due to posting additional collateral to securitize first lien counterparties in anticipation of the refinancing. We expect a portion of this additional collateral to be returned as these counterparties become parties to the new first lien collateral pool that was created with the new Credit Agreement. The counterparties under such agreements would share the benefits of the collateral subject to such first priority liens ratably with the lenders under the credit agreements.

The fair value of our derivatives collateralized by first priority liens included liabilities of $99 million, $118 million and $98 million at April 23, 2013, March 31, 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 entails.

Investing Activities

Capital Expenditures. We had capital expenditures of approximately $20 million and $9 million during the three months ended March 31, 2013 and 2012, respectively. Our capital spending by reportable segment was as follows:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012
Coal (1)	$12	$—
Gas	8	8
Other and eliminations	—	1
Total	$20	$9

(1) On September 1, 2011, we completed the DMG Transfer; therefore, Coal capital expenditures were not included for the three months ended March 31, 2012. On June 5, 2012, we completed the DMG Acquisition; therefore, Coal

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capital expenditures were included for the three months ended March 31, 2013. For the three months ended March 31, 2012, Coal capital expenditures were $23 million.

Other Investing Activities. During the three months ended March 31, 2013, there was a $13 million cash inflow related to restricted cash balances related to the release of unused cash collateral associated with the DPC LC and DMG LC facilities. These proceeds were used to fund a portion of the repayments of the DMG and DPC Credit Agreements as further discussed below.

During the three months ended March 31, 2012, there was a $148 million cash inflow related to restricted cash balances associated with the DPC LC facilities and DPC Credit Agreement. During the first quarter of 2012, we requested the release of unused cash collateral related to the DPC LC facilities.

Financing Activities

Historical Cash Flow from Financing Activities. Cash flow used in financing activities totaled $31 million for the three months ended March 31, 2013 due to $28 million in repayments of borrowings on the DMG and DPC Credit Agreements and $3 million in financing costs in connection with the DPC Revolving Credit Agreement.

Cash flow used in financing activities totaled $3 million for the three months ended March 31, 2012 due to repayments of borrowings on the DPC Credit Agreement.

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. During the three months ended March 31, 2013, we were not subject to any 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 debt, the outstanding debt used in this calculation is limited to the amounts outstanding under the Tranche B-2 Term Loan.

Please read Note 19—Subsequent Events 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:

	Standard & Poor	Moody’s
Dynegy Inc.:		
Corporate Family Rating	B	B2
Senior Secured	BB-	B2

Disclosure of Contractual Obligations and Contingent Financial Commitments

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. Contingent financial commitments represent obligations that become payable only if certain pre-defined events occur, such as financial guarantees.

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 months ended March 31, 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 requires us to allocate the reorganization value to our assets and liabilities in a manner similar to the acquisition method of accounting for business combinations. Under the provisions of fresh-start accounting, a new entity has been created for financial reporting purposes. 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; therefore, the results of our Coal segment are not included for the three months ended March 31, 2012. Additionally, on June 5, 2012, we reacquired the Coal segment through the DMG Acquisition; therefore, the results of our Coal segment are included for the three months ended March 31, 2013.

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.

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

EBITDA and Adjusted EBITDA. We define EBITDA as earnings (loss) before interest expense, income tax expense (benefit) and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA adjusted to exclude (i) gains or losses on the sale of assets, (ii) the impacts of mark-to-market changes on economic hedges related to our generation portfolio, (iii) the impact of impairment charges and certain other costs such as those associated with the acquisition of AER and bankruptcy proceedings, (iv) amortization of intangible assets and liabilities and (v) 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, Legacy Dynegy, for the periods prior to the Merger.

We believe EBITDA and Adjusted EBITDA provide meaningful representations of our operating performance. We consider EBITDA as another way to measure financial performance on an ongoing basis. 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.

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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).

Consolidated Summary Financial Information — Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012

The following table provides summary financial data regarding our consolidated results of operations for the three months ended March 31, 2013 and 2012, respectively:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	$ Change	% Change
Revenues	$318	$268	$50	19 %
Cost of sales	(284)	(180)	(104)	(58)%
Gross margin, exclusive of depreciation shown separately below	34	88	(54)	(61)%
Operating and maintenance expense, exclusive of depreciation shown separately below	(71)	(34)	(37)	(109)%
Depreciation and amortization expense	(54)	(22)	(32)	(145)%
Gain on sale of assets, net	1	—	1	100 %
General and administrative expense	(22)	(20)	(2)	(10)%
Acquisition and integration costs	(3)	—	(3)	(100)%
Operating income (loss)	(115)	12	(127)	(1,058)%
Bankruptcy reorganization items, net	(1)	152	(153)	(101)%
Interest expense	(28)	(31)	3	10 %
Impairment of Undertaking receivable, affiliate	—	(832)	832	100 %
Other income and expense, net	2	24	(22)	(92)%
Loss from continuing operations before income taxes	(142)	(675)	533	79 %
Income tax benefit	—	6	(6)	(100)%
Loss from continuing operations	$(142)	$(669)	527	79 %
Loss from discontinued operations, net of tax	—	(413)	413	100 %
Net loss	$(142)	$(1,082)	$940	87 %

The DNE Debtor Entities did not emerge from Chapter 11 protection on October 1, 2012 and continue to operate their businesses as “debtors-in-possession.” Therefore, the DNE Debtor Entities were deconsolidated as of October 1, 2012. Accordingly, we have reclassified DNE’s operating results as discontinued operations in the consolidated financial statements for all periods presented.

The following tables provide summary financial data regarding our operating income (loss) by segment for the three months ended March 31, 2013 and 2012, respectively:

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	Successor			
	Three Months Ended March 31, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$87	$231	$—	$318
Cost of sales	(115)	(169)	—	(284)
Gross margin, exclusive of depreciation shown separately below	(28)	62	—	34
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(40)	(30)	(1)	(71)
Depreciation and amortization expense	(13)	(40)	(1)	(54)
Gain on sale of assets, net	1	—	—	1
General and administrative expense	—	—	(22)	(22)
Acquisition and integration costs (1)	—	—	(3)	(3)
Operating loss	$(80)	$(8)	$(27)	$(115)

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

	Predecessor		
	Three Months Ended March 31, 2012		
(amounts in millions)	Gas	Other	Total
Revenues	$268	$—	$268
Cost of sales	(180)	—	(180)
Gross margin, exclusive of depreciation shown separately below	88	—	88
Operating and maintenance expense, exclusive of depreciation and amortization expense shown separately below	(34)	—	(34)
Depreciation and amortization expense	(20)	(2)	(22)
General and administrative expense	—	(20)	(20)
Operating income (loss)	$34	$(22)	$12

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The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the three months ended March 31, 2013:

	Successor			
	Three Months Ended March 31, 2013			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(142)
Bankruptcy reorganization items, net				1
Interest expense				28
Other items, net				(2)
Operating loss	$(80)	$(8)	$(27)	$(115)
Depreciation and amortization expense	13	40	1	54
Bankruptcy reorganization items, net	—	—	(1)	(1)
Other items, net	—	1	1	2
EBITDA	(67)	33	(26)	(60)
Bankruptcy reorganization items, net	—	—	1	1
Acquisition and integration costs	—	—	3	3
Mark-to-market (income) loss, net	40	(4)	—	36
Amortization of intangible assets and liabilities (1)	31	32	—	63
Enterprise-wide Adjusted EBITDA	$4	$61	$(22)	$43

(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 March 31, 2012:

	Predecessor			
	Three Months Ended March 31, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(1,082)
Loss from discontinued operations, net of tax				413
Income tax benefit				(6)
Impairment of Undertaking receivable, affiliate				832
Bankruptcy reorganization items, net				(152)
Interest expense				31
Other items, net				(24)
Operating income (loss)	$—	$34	$(22)	$12
Impairment of Undertaking receivable, affiliate	—	—	(832)	(832)
Bankruptcy reorganization items, net	—	—	152	152
Depreciation and amortization expense	—	20	2	22
Other items, net	—	—	24	24
EBITDA from continuing operations	—	54	(676)	(622)
Impairment of Undertaking receivable, affiliate	—	—	832	832
Bankruptcy reorganization items, net	—	—	(152)	(152)
Interest income on Undertaking receivable	—	—	(24)	(24)
Restructuring costs and other expense	—	—	5	5
Sithe amortization	—	10	—	10
Mark-to-market income, net	—	(25)	—	(25)
Premium adjustment	—	1	—	1
Adjusted EBITDA from continuing operations	$—	$40	$(15)	$25
Adjusted EBITDA from Legacy Dynegy (1)	22	—	(9)	13
Enterprise-wide Adjusted EBITDA	$22	$40	$(24)	$38

(1) Our first quarter 2012 consolidated results 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. As a result, the results of our Coal segment, as well as certain items in the Other segment, related to Legacy Dynegy, are not included in our consolidated results for the three months ended March 31, 2012. However, we have included the Adjusted EBITDA from Legacy Dynegy for the three months ended March 31, 2012 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):

	Three Months Ended March 31, 2012		
(amounts in millions)	Coal	Other	Total
Operating income (loss)	$2	$(23)	$(21)
Depreciation and amortization expense	50	—	50
EBITDA	52	(23)	29
Restructuring charges	—	14	14
Mark-to-market income, net	(30)	—	(30)
Adjusted EBITDA from Legacy Dynegy	$22	$(9)	$13

Overview

Our results of operations are impacted by the following 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. This amount includes the results of operations related to the Coal segment for the three months ended March 31, 2012.
- 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 first quarter 2013 results include the amortization of intangible assets and liabilities that did not exist in the first quarter 2012. In addition, our property, plant and equipment had a significantly lower basis in the first quarter 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 first quarter 2013 results that have no corresponding amounts in our first quarter 2012 results.

We believe providing a reconciliation of the impact of these significant items provides the basis for a more meaningful comparison of our first quarter 2013 results to our first quarter 2012 results.

Discussion of Consolidated Results of Operations

Revenues. Revenues increased by $50 million from $268 million for the three months ended March 31, 2012 to $318 million for the three months ended March 31, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change
As reported	$318	$ 268	$50
Plus:			
DMG Transfer	—	177	(177)
Less:			
Fresh-start adjustments	(23)	—	(23)
Total as adjusted	$341	$ 445	$(104)

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 decrease in revenues was $104 million. This decrease is primarily due to a $110 million reduction in mark-to-market revenues as a result of net mark-to-market losses in the three months ended March 31, 2013 compared to mark-to-market gains in the three months ended March 31, 2012. Please read our Discussion of Segment Results of Operations below.

Cost of Sales. Cost of sales increased by $104 million from $180 million for the three months ended March 31, 2012 to $284 million for the three months ended March 31, 2013. The following table summarizes the impact of significant items that contributed to the variance:

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(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change
As reported	$ (284)	$ (180)	$ (104)
Plus:			
DMG Transfer	—	(86)	86
Less:			
Fresh-start adjustments	(31)	—	(31)
Total as adjusted	$ (253)	$ (266)	$ 13

The $31 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. After considering the impact of significant items, the decrease in cost of sales was $13 million. This decrease is primarily due to a decrease in natural gas expense due to lower generation volumes in the Gas segment which was partially offset by higher rail costs due to a contract amendment, 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 $37 million from $34 million for the three months ended March 31, 2012 to $71 million for the three months ended March 31, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change
As reported	$ (71)	$ (34)	$ (37)
Plus:			
DMG Transfer	—	(39)	39
Total as adjusted	$ (71)	$ (73)	$ 2

After considering the impact of significant items, the decrease in operating and maintenance expense was $2 million, which is primarily due to higher planned outage costs in the first quarter 2012 compared to the first quarter 2013.

Depreciation and Amortization Expense. Depreciation expense increased by $32 million from $22 million for the three months ended March 31, 2012 to $54 million for the three months ended March 31, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change
As reported	$ (54)	$ (22)	$ (32)
Plus:			
DMG Transfer	—	(50)	50
Less:			
Fresh-start adjustments	32	—	32

Total as adjusted	$ (86)	$ (72)	$ (14)

The $32 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 increase in depreciation and amortization expense was $14 million, which is primarily related to the timing of various projects

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being placed into service, partially offset by 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 the first quarter 2013.
General and Administrative Expense. General and administrative expense increased by $2 million from $20 million for the three months ended March 31, 2012 to $22 million for the three months ended March 31, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change
As reported	$(22)	$(20)	$(2)
Plus:			
DMG Transfer	—	(9)	9
Total as adjusted	$(22)	$(29)	$7

After considering the impact of significant items, the decrease in general and administrative expense was $7 million. This decrease is primarily related to lower legal expenses in the first quarter 2013 compared to the first quarter 2012.
Acquisition and Integration Costs. Acquisition and integration costs totaled $3 million for the three months ended March 31, 2013 and were incurred in connection with our pending acquisition of AER. There were no such costs incurred during the three months ended March 31, 2012. Please read Note 3—Acquisitions for further discussion.
Bankruptcy Reorganization Items, Net. Bankruptcy reorganization items, net decreased by $153 million from a gain of $152 million for the three months ended March 31, 2012 to a loss of $1 million for the three months ended March 31, 2013. The first quarter 2013 Bankruptcy reorganization items, net consisted primarily of $1 million in professional and advisor fees. The first quarter 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, partially offset by $19 million in expenses incurred related to advisors.

Interest Expense. Interest expense decreased by $3 million from $31 million for the three months ended March 31, 2012 to $28 million for the three months ended March 31, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change
As reported	$(28)	$(31)	$3
Plus:			
DMG Transfer	—	(13)	13
Less:			
Fresh-start adjustments	8	—	8
Total as adjusted	$(36)	$(44)	$8

The $8 million included in Fresh-start adjustments relates 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 $8 million, which 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. Please read Note 18—Debt in our Form 10-K for further discussion.

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. 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 three months ended March 31, 2013.

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Other Income and Expense, net. Other income and expense, net decreased by $22 million from $24 million for the three months ended March 31, 2012 to $2 million for the three months ended March 31, 2013. The decrease is primarily due to interest income on the Undertaking receivable, affiliate during the first quarter 2012. The Undertaking was executed on September 1, 2011, impaired as of March 31, 2012 and settled on June 5, 2012; therefore, there is three months of interest income related to the Undertaking during the three months ended March 31, 2012. The Undertaking was settled upon execution of the Settlement Agreement; therefore, there is no interest income related to the Undertaking during the three months ended March 31, 2013. This decrease was partially offset by miscellaneous income in the first quarter 2013.

Income Tax Benefit. We reported an income tax benefit of zero for the three months ended March 31, 2013 compared to an income tax benefit from continuing operations of $6 million for the three months ended March 31, 2012. The effective tax rate in the first quarter 2013 was zero percent compared to 1 percent for the first quarter 2012.

For the three months ended March 31, 2013, the difference between the effective rate of zero 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 March 31, 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 March 31, 2012, the difference between the effective rate of 1 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 March 31, 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.

Discontinued Operations. For the three months ended March 31, 2012, our loss from discontinued operations, net of tax was $413 million primarily related to the DNE operations. Discontinued operations in the first quarter 2012 related primarily 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. The remaining amount in Discontinued operations related to operating losses of the DNE Debtor Entities. There were no such charges during the three months ended March 31, 2013 as the DNE Debtor Entities were deconsolidated effective October 2, 2012.

Enterprise-wide Adjusted EBITDA. Enterprise-wide Adjusted EBITDA increased by $5 million from $38 million for the three months ended March 31, 2012 to $43 million for the three months ended March 31, 2013. The increase is primarily due to improved spark spreads at our Independence facility in the first quarter 2013 compared to the first quarter 2012. Offsetting these increases is a decrease in the Coal segment adjusted EBITDA due to an increase in basis differentials, less uplift from hedges and lower generation volumes. Coal segment generation volumes were down due to an increase in outages and derates.

Discussion of Segment Results of Operations

Coal Segment. Realized power prices were lower in the first quarter 2013 compared to the first quarter 2012. The decrease in period over period realized power prices was driven by greater basis differentials in the first quarter 2013 compared to the first quarter 2012. Generation volumes also decreased period over period due to increased planned outages and derates. As a result of the DMG Transfer, the results of the Coal segment are not included in our first quarter 2012 results; however, we have included the results of the Coal segment from Legacy Dynegy for the three months ended March 31, 2012 for comparative purposes.

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The following table provides summary financial data regarding our Coal segment results of operations for the three months ended March 31, 2013 and 2012, respectively:

(dollars in millions)	Successor Three Months Ended March 31, 2013	Legacy Dynegy Three Months Ended March 31, 2012	Change	% Change
Revenues:				
Energy	$119	$124	$(5)	(4)%
Financial transactions:				
Mark-to-market income (loss)	(40)	30	(70)	(233)%
Financial settlements	10	23	(13)	(57)%
Total financial transactions	(30)	53	(83)	(157)%
Other (1)	(2)	—	(2)	(100)%
Total revenues	87	177	(90)	(51)%
Cost of sales	(115)	(86)	(29)	(34)%
Gross margin	$(28)	$91	$(119)	(131)%
Million Megawatt Hours Generated (2)	5.0	5.6	(0.6)	(11)%
In Market Availability for Coal-Fired Facilities (3)	89%	94%		
Average Quoted On-Peak Market Power Prices ($/MWh) (4):				
Indiana (Indy Hub)	$34	$30	$4	13%

(1) Other includes 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 three months ended March 31, 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 three months ended March 31, 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 three months ended March 31, 2013 and 2012, respectively, and does not necessarily reflect prices we realized.

Gross margin for Coal decreased by $119 million from income of $91 million for the three months ended March 31, 2012 to a loss of $28 million for the three months ended March 31, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change
As reported	$(28)	$ —	$(28)
Plus:			
DMG Transfer	—	91	(91)
Less:			

Fresh-start adjustments	(31)	—	(31)
Total as adjusted	$3	$ 91	$(88)

The $31 million included in Fresh-start adjustments relates to the amortization of intangible assets and liabilities associated with rail transportation and coal purchase contracts recorded in connection with the application of fresh-start

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accounting on the Plan Effective Date. After considering the impact of significant items, the decrease in gross margin was $88 million and is primarily attributable to the following:

- Mark-to-market revenue decreased by $70 million due to a net change from mark-to-market revenues of $30 million in the first quarter 2012 to mark-to-market losses of $40 million in the first quarter 2013. This change is driven by price movements and changes in open positions.
- Settlement revenue decreased by $13 million primarily due to a decrease in revenue associated with power swaps. While the settlement of the Coal segment hedges provide an uplift to gross margin in both periods, the uplift was greater in the first quarter 2012 as those hedges were initiated when prices were considerably higher.

Gas Segment. Spark-spreads were generally lower in the first quarter 2013 compared to the first quarter 2012, resulting in lower generation volumes period over period, with the exception of our Independence facility where both generation volumes and spark spreads were higher in the first quarter of 2013 compared to the first quarter of 2012.

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The following table provides summary financial data regarding our Gas segment results of operations for the three months ended March 31, 2013 and 2012, respectively:

(dollars in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change	% Change
Revenues:				
Energy	$169	$159	$10	6 %
Capacity	32	47	(15)	(32)%
RMR	1	1	—	— %
Tolls	2	20	(18)	(90)%
Natural gas	22	32	(10)	(31)%
Financial transactions:				
Mark-to-market income	3	43	(40)	(93)%
Financial settlements	(9)	(41)	32	78 %
Option premiums	1	(1)	2	200 %
Total financial transactions	(5)	1	(6)	(600)%
Other (1)	10	8	2	25 %
Total revenues	231	268	(37)	(14)%
Cost of sales	(169)	(180)	11	6 %
Gross margin	$62	$88	$(26)	(30)%
Million Megawatt Hours Generated (2)	4.3	5.9	(1.6)	(27)%
Average Capacity Factor for Combined Cycle Facilities (3)	45 %	61 %		
Average Market On-Peak Spark Spreads ($/MWh) (4):				
Commonwealth Edison (NI Hub)	$9	$12	$(3)	(25)%
PJM West	$13	$15	$(2)	(13)%
North of Path 15 (NP 15)	$12	$5	$7	140 %
New York—Zone A	$17	$9	$8	89 %
Mass Hub	$15	$11	$4	36 %
Average Market Off-Peak Spark Spreads ($/MWh) (4):				
Commonwealth Edison (NI Hub)	$2	$7	$(5)	(71)%
PJM West	$5	$9	$(4)	(44)%
North of Path 15 (NP 15)	$7	$—	$7	NM
New York—Zone A	$11	$4	$7	175 %
Mass Hub	$(4)	$5	$(9)	(180)%
Average natural gas price—Henry Hub ($/MMBtu) (5)	$3.48	$2.46	$1.02	41 %

(1) Other includes ancillary services and other miscellaneous items.
(2) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility for the three months ended March 31, 2013 and 2012, respectively.
(3) Reflects actual production as a percentage of available capacity.
(4) Reflects the simple average of the spark spread available to a 7.0 MMBtu/MWh heat rate generator selling power at day-ahead prices and buying delivered natural gas at a daily cash market price and does not reflect spark spreads available to us.
(5) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

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Gross margin for Gas decreased by $26 million from $88 million for the three months ended March 31, 2012, to $62 million for the three months ended March 31, 2013. The following table summarizes the impact of significant items that contributed to the variance:

(amounts in millions)	Successor Three Months Ended March 31, 2013	Predecessor Three Months Ended March 31, 2012	Change
As reported	$ 62	$ 88	$ (26)
Less:			
Fresh-start adjustments	(23)	—	(23)
Total as adjusted	$ 85	$ 88	$ (3)

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 and gas transportation contracts 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 gross margin was $3 million and is primarily attributable to the following:

- Mark-to-market revenue decreased by $40 million due to a net change in mark-to-market revenue of $43 million in the first quarter 2012 to $3 million in the first quarter 2013. This change is driven by price movements and changes in open positions.

The above decrease was partially offset by the following:

- Energy revenue increased by $10 million and the corresponding Cost of sales decreased by $11 million, partially offset by a decrease in Gas revenues of $10 million, for a net increase in energy margin of $11 million. Energy margin increased due primarily to improved spark spreads at our Independence facility. The increase from our Independence facility was offset by lower generation volumes at all other Gas segment facilities, which was driven by an extended outage at Kendall and lower spark spreads. The decrease in Gas revenues is due to higher volumes at our Independence facility which resulted in less volumes being available to sell.
- Settlement revenue increased by $32 million primarily due to the settlement of out of the money gas positions in the first quarter 2012 that was not repeated in the first quarter 2013.

Outlook

We expect that our future financial results will continue to change based upon fuel and commodity prices, especially 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 or more stringent air emission standards.

Our future financial results will also be impacted by changes to our capital structure. In April 2013, we entered into two seven-year term loans, which include an $800 million tranche and a $500 million tranche, the latter of which we may refinance during 2013. Please read Note 19—Subsequent Events for further discussion.

On March 14, 2013, IPH entered into the AER Transaction Agreement, whereby IPH will acquire AER 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. The closing is expected to occur in the fourth quarter 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.

Currently, our Coal expected generation volumes are 68 percent hedged volumetrically for 2013 and approximately 26 percent hedged volumetrically for 2014. We plan to continue our hedging program for Coal over a one- to two-year period

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using various instruments. Beyond 2013, the portfolio is largely open, positioning Coal to benefit from possible future power market pricing improvements.

Currently, our expected coal requirements are 97 percent contracted and priced in 2013. Our forecasted coal requirements for 2014 are 86 percent contracted and 66 percent priced. Our coal transportation requirements are 100 percent contracted and priced through 2013 when our current contracts expire. In August 2012, we executed new coal transportation contracts which take effect when our current contracts expire. These new long-term contracts also cover 100 percent of our coal transportation requirements. 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 is likely caused by excess capacity conditions prevailing in MISO for the term of the planning year. In the future, increased market participation by demand response resources offset by potential retirement of marginal MISO coal capacity due to poor economics or expected environmental mandates could also affect MISO capacity and energy pricing.

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.

Further, we have started negotiations with the union (IBEW Local 51) regarding its collective bargaining agreement, which is set to expire on June 30, 2013. This agreement covers approximately 400 represented employees at our four Coal plants located in Illinois.

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 load-serving entities 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 load-serving entities 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.

In May 2012, SCE notified Morro Bay and Moss Landing that it was terminating certain energy and capacity contracts with those entities. We are disputing the validity of the purported terminations and subsequent actions by SCE. Such terminations will likely impact the timing and amount of cash flows going forward. We are actively seeking other commercial arrangements for the facilities and have been offering output in the day-ahead market administered by the CAISO since May 2012. We will continue to respond to the RFO process of California utilities seeking to procure electric capacity needed to serve their customers. While we have been successful in winning contracts through this RFO process in the past, we believe that a more forward-looking, transparent, market-based solution to securing electric supply would benefit consumers, utilities and independent generators within the CAISO footprint.

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, consisting of the below grade structures, is expected to commence shortly. 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 escrow funds to cover costs through at least 2013.

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 the ultimate impact of the California Water Intake Policy, we may determine that we would be required to install cooling systems that could render operation of the units uneconomical. If such a determination were to be made, we could decide to reduce operations or cease to operate the units as early as December 31, 2017.

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. Efforts to implement prospective improvements in the forward capacity market design are currently underway, which include migration to a demand curve and/or removal of the auction floor for Forward Capacity Auction #8 and beyond. We anticipate changes will impact the Forward Capacity Auction #8, which is the auction period from June 2017 to May 2018.

In PJM, where the Kendall and Ontelaunee combined-cycle plants are located, nine 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 2015-2016 Planning Year, which cleared at $4.14 per kW-month (Kendall) and $5.09 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 2012-2013 at $0.82 per kW-month for the rest of state market. The winter 2013-2014 capacity is also showing a considerable rebound from the aforementioned 2012-2013 market, currently valued at $2.35 per kW-month. 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 April 23, 2013, our Gas portfolio is 83 percent hedged volumetrically through 2013 and approximately 26 percent hedged volumetrically for 2014.

We plan to continue our hedging program for Gas over a one- to two-year period using various forward sale instruments. Beyond 2013, the portfolio is largely open, positioning Gas to benefit from possible future power market pricing improvements.

Environmental and Regulatory Matters

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

The 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. 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 put systems in place in order to monitor our swap activity and prepare for upcoming Non-Swap Dealer/Major Swap Participant reporting requirements. 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. On January 24, 2013, the court denied petitions for rehearing. On March 29, 2013, the EPA and environmental groups filed petitions for writ of certiorari with the Supreme Court. In spring 2013, the EPA also held stakeholder meetings with states to discuss approaches for determining how emissions in upwind states impact air quality in downwind states and next steps to address the transport of air pollution across state boundaries. 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.

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The Clean Water Act

Effluent Limitation Guidelines. On April 19, 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 ELG proposal will be subject to a 60-day comment period. The timing and ultimate requirements of the final rule ELG 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.

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 April 2013, we submitted action plans to the EPA responding to each report's recommendations. We plan on performing the recommended further studies and other actions, 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

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 response to further discussions with the Illinois EPA, in March 2013 we submitted proposals to evaluate options concerning our proposed corrective action plans at Vermilion and to perform a further hydrogeological 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. On June 26, 2012, the U.S. Court of Appeals for the District of Columbia Circuit upheld the EPA's finding that GHG emissions from motor vehicles cause or contribute to air pollution that endangers the public health and welfare and several EPA GHG-related rules in Coalition For Responsible Regulation, Inc., et al. v. EPA. In December 2012, the court denied petitions for rehearing. In spring 2013, several petitions for writ of certiorari were filed with the Supreme Court.

State Regulation of Greenhouse Gases. On March 13, 2013, RGGI held its nineteenth auction, in which approximately 38 million allowances for the second control period were sold at a clearing price of $2.80 per allowance. RGGI's next quarterly auction is scheduled for June 5, 2013. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets.

Based on projected emissions and the $2.80 per allowance clearing price in RGGI's most recent auction, we estimate the cost of allowances required to operate our affected facilities during 2013 will be approximately $6 million.

In April 2013, California took several actions to link CARB's GHG program to the Canadian province of Quebec's GHG program. The linkage of the two programs is set to begin January 1, 2014. Due in part to the linkage actions, the price of California GHG allowances in secondary markets has trended upward with allowances currently trading in a range of $14.50 to $15.50 per ton.

We participated in CARB's last quarterly allowance auction and will procure additional allowances as needed in future auctions and secondary markets. CARB's next quarterly allowance action is scheduled for May 16, 2013. Based on the current

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secondary market allowance price of approximately $15 per ton, our estimated cost of allowances required to operate our affected facilities during 2013 will be approximately $20 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.

In April 2013, a coalition of business interests filed a lawsuit in California state court challenging the legality of CARB's GHG allowance auction. CARB also has started a public process to propose additional amendments to the cap-and-trade program in fall 2013. We will continue to monitor judicial and rulemaking developments regarding the California cap-and-trade program and evaluate any potential impacts on our operations.

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 Three Months Ended March 31, 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	(32)
Contracts realized or otherwise settled during the period	(6)
Changes in collateral/margin netting	12
Fair value of portfolio at March 31, 2013	$(76)

The net risk management liability of $76 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 March 31, 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)	$(99)	$(50)	$(26)	$(16)	$(7)	$—	$—
Prices based on models (2)	3	3	—	—	—	—	—
Total (3)	$(96)	$(47)	$(26)	$(16)	$(7)	$—	$—

(1) Prices obtained from actively traded, liquid markets for commodities.

(2) The market quotations and prices based on models categorization differ from the categories of Level 1, Level 2 and Level 3 used in our fair value disclosures due to the application of the different methodologies. Please read Note 7—Fair Value Measurements for further discussion.

(3) Excludes $17 million of margin and $3 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 or our management expect, 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,”

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"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, including satisfying closing conditions;
- anticipated benefits and expected synergies resulting from the AER Acquisition and beliefs associated with the integration of operations;
- our ability to consummate the Danskammer facility sale in accordance with the Chapter 11 Joint Plan of Liquidation and asset purchase agreement;
- 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, 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;
- beliefs and assumptions regarding the outcome of the SCE contract terminations dispute and the impact of such terminations on the timing and amount of future cash flows;
- 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.

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 and 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. Following is a discussion of the more material of these risks and our relative exposures as of March 31, 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 "Value at Risk" in our Form 10-K for a complete description of our valuation methodology. The decrease in the March 31, 2013 VaR was primarily due to decreased forward sales as compared to December 31, 2012.

Daily and Average VaR for Risk-Management Portfolios

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

Credit Risk. The following table represents our credit exposure at March 31, 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	$1	$—	$1
Utility and power generators	1	—	1
Commercial / industrial / end users	—	—	—
Total	$2	$—	$2

Interest Rate Risk

We are exposed to fluctuating interest rates related to variable rate financial obligations. On April 23, 2013, we refinanced our DMG and DPC Credit Agreements with the approximate $1.8 billion Credit Agreement, which is considered variable rate debt. We use a variety of instruments, including interest rate swaps and caps, 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. Based on a sensitivity analysis of the variable rate financial obligations in our debt portfolio as of April 23, 2013, to the extent LIBOR remains below 1.0 percent, which represents the interest rate floor in the Credit Agreement, each 50 basis point decrease in LIBOR rates will increase interest expense by approximately $1 million over the twelve months ended March 31, 2014. We estimate that increases in LIBOR to ranges between 1.0 percent and 2.5 percent will result in up to $16 million in increased interest expense over the twelve months ended March 31, 2014 as the higher interest expense on the debt would be partially increased by the change in interest expense on the swaps. For these same twelve months, each additional 50 basis point increase in LIBOR above 2.5 percent would decrease the interest expense recognized over the period by approximately $250 thousand, as the change in value of the interest rate hedging instruments would more than offset the increase in debt expense for the variable rate debt over the period.

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The absolute notional financial contract amounts associated with our interest rate contracts were as follows at March 31, 2013 and December 31, 2012, respectively:

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

(1) The $1,100 million interest rate swaps are not effective until the fourth quarter 2013.
(2) The $1,400 million interest rate caps expire October 31, 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 March 31, 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 March 31, 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 for factors, risks and uncertainties that may affect future results.
We may be unable to obtain the regulatory approvals required to complete the AER Acquisition or, in order to do so, we may be required to comply with material restrictions on our conduct or satisfy other material conditions required by various regulatory authorities.
Consummation of the AER Acquisition is subject to conditions, including FERC approval, approval of license transfers by the FCC and confirmation by the Illinois Pollution Control Board of the continuing effectiveness of AER's air variance. The closing of the AER Acquisition is also subject to the condition that there be no injunction or order issued by a court of competent jurisdiction that prevents the consummation of the transactions contemplated by the AER Transaction Agreement. We can provide no assurance that all required regulatory approvals will be obtained.
Further, IPH has agreed to avoid or eliminate any impediment to the transactions that may be asserted by governmental entities under the antitrust laws, including by divesting assets and committing to limitations on IPH's conduct. There can be no assurance as to the cost, scope or impact of the actions that may be required to obtain the required regulatory approvals. Furthermore, these actions could have the effect of delaying or preventing completion of the proposed transactions or imposing additional costs on or limiting the revenues and profitability of IPH following the consummation of the transactions.
Furthermore, the FERC, state attorney general or other governmental authorities could seek to block or challenge the transactions as they deem necessary or desirable in the public interest at any time, including after completion of the transactions. In addition, in some circumstances, a competitor, customer or other third party could initiate a private action under antitrust laws challenging or seeking to enjoin the transactions, before or after it is completed. We may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.
Failure to successfully integrate AER's coal generation and retail marketing business with our existing generation business in the expected time frame may materially and adversely affect our financial condition, results of operations and cash flows.
The success of the proposed transactions will depend, in part, on our ability to realize the anticipated benefits and synergies from combining AER's coal generation and retail marketing business and our existing generation business. To realize these anticipated benefits, the businesses must be successfully combined. If the combined businesses are not able to achieve our objectives, or are not able to achieve our objectives on a timely basis, the anticipated benefits of the transactions may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the transactions. These integration difficulties could materially and adversely affect our financial condition, results of operations and cash flows.
Restrictive covenants may adversely affect operations.
The Credit Agreement contains various covenants that limit our ability to, among other things:

- incur additional indebtedness;
- pay dividends, repurchase or redeem stock or make investments in certain entities;
- enter into related party transactions;
- create certain liens;
- enter into any agreements which limit the ability of certain subsidiaries to make dividends or otherwise transfer cash or assets to us or certain other subsidiaries;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets; and
- sell and acquire assets.

In addition, the Credit Agreement contains a financial covenant, if we have utilized 25 percent or more of our Revolving Facility, that specifies maximum thresholds for our senior secured leverage ratio (as defined in the Credit Agreement). All of these restrictions may affect our ability to operate our respective businesses, may limit our ability to take advantage of potential business opportunities as they arise and may adversely affect the conduct of our current businesses,

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including restricting our ability to finance future operations and capital needs and limiting our ability to engage in other business activities.

Item 2—UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

When restricted stock awarded by Dynegy becomes taxable compensation to employees, shares may be withheld to cover the employees' withholding taxes. We did not have any purchases of equity securities by means of such share withholdings during the three months ended March 31, 2013. We do not have a stock repurchase program.

Item 6—EXHIBITS

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

Exhibit Number	Description
*2.1	Transaction Agreement by and between Ameren Corporation and Illinois Power Holdings, LLC, dated as of March 14, 2013 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 15, 2013 File No. 001-33443).
2.2	Confirmation Order for Dynegy Northeast Generation, Inc., Hudson Power, L.L.C., Dynegy Danskammer, L.L.C., and Dynegy Roseton, L.L.C., as entered by the Bankruptcy Court on March 15, 2013 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 19, 2013 File No. 001-33443).
10.1	Limited Guaranty, dated March 14, 2013, by Dynegy Inc. in favor of Ameren Corporation (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 15, 2013 File No. 001-33443).
10.2	Form of Stock Unit Award Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.3	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.4	Form of Performance Award Agreement (for Managing Directors and Above) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.5	First Amendment to Employment Agreement by and between Dynegy Operating Company and Henry D. Jones (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.6	Second Amendment to Employment Agreement by and between Dynegy Operating Company and Robert C. Flexon (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.7	Second Amendment to Employment Agreement by and between Dynegy Operating Company and Clint C. Freeland (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.8	Second Amendment to Employment Agreement by and between Dynegy Operating Company and Catherine B. Callaway (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.9	Second Amendment to Employment Agreement by and between Dynegy Operating Company and Carolyn J. Burke (incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.10	Second Amendment to the Dynegy Inc. Executive Change in Control Severance Pay Plan (incorporated by reference to Exhibit 10.9 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2013 File No. 001-33443).
10.11	Credit Agreement, dated as of April 23, 2013, among Dynegy Inc., as borrower and the guarantors, lenders and other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
10.12	Guarantee and Collateral Agreement, dated as of April 23, 2013 among Dynegy Inc., the subsidiaries of the borrower from time to time party thereto and Credit Suisse AG, Cayman Islands Branch, as Collateral Trustee(incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
10.13	Collateral Trust and Intercreditor Agreement, dated as of April 23, 2013 among Dynegy, the Subsidiary Guarantors (as defined therein), Credit Suisse AG, Cayman Islands Branch and each person party thereto from time to time (incorporated by reference to Exhibit 10.3 to the Current

	Report on Form 8-K of Dynegy Inc. filed on April 24, 2013 File No. 001-33443).
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
†32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

†32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Pursuant to Item 6.01(b)(2) of Regulation S-K exhibits and schedules are omitted. Dynegy agrees to furnish supplementally a copy of any omitted schedule or exhibit upon request.

** 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:	May 2, 2013	By:	/s/ CLINT C. FREELAND Clint C. Freeland Executive Vice President and Chief Financial Officer