DYNEGY INC.
Form 10-K
February 27, 2014
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 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 ________

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

Commission File Number	State of Incorporation	I.R.S. Employer Identification No.
001-33443	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)

Securities registered pursuant to Section12(b) of the Act:

Title of each class	Name of each exchange on which registered
Dynegy’s common stock, $0.01 par value	New York Stock Exchange
Dynegy's warrants, exercisable for common stock at an exercise price of $40 per share	New York Stock Exchange

Securities registered pursuant to Section12(g) of the Act:
None
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No ý

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 ¨

Table of Contents

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨

No x

As of June 30, 2013, the aggregate market value of the Dynegy Inc. common stock held by non-affiliates of the registrant was $1,554,741,906 based on the closing sale price as reported on the New York Stock Exchange.

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 ¨

Number of shares outstanding of Dynegy Inc.'s class of common stock, as of the latest practicable date: Common stock, $0.01 par value per share, 100,203,267 shares outstanding as of February 21, 2014.

DOCUMENTS INCORPORATED BY REFERENCE

Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant's 2014 Annual Meeting of Stockholders, which the registrant intends to file no later than 120 days after December 31, 2013. However, if such proxy statement is not filed within such 120-day period, Items 10, 11, 12, 13 and 14 will be filed as part of an amendment to this Form 10-K no later than the end of the 120-day period.

Table of Contents

DYNEGY INC.
FORM 10-K
TABLE OF CONTENTS

PART I
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-K, the abbreviations contained herein have the meanings set forth below.

AEM	Ameren Energy Marketing Company
AER	New Ameren Energy Resources, LLC
AEGC	Ameren Energy Generating Company
AERG	New AERG, LLC
AOCI	Accumulated other comprehensive income
APA	Asset purchase agreement
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BACT	Best Available Control Technology (air)
BTA	Best Technology Available
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	The California Independent System Operator
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CCA	California Carbon Allowances
CCR	Coal Combustion Residuals
CEC	California Energy Commission
CERCLA	The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	U.S. Commodity Futures Trading Commission
CO_2	Carbon dioxide
CO_{2e}	The climate change potential of other GHGs relative to the global warming potential of CO_2
CPUC	California Public Utility Commission
CRCG	Commodity Risk Control Group
CS	Credit Suisse
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DB	DB Energy Trading, LLC
DCF	Discounted cash flow
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.
DMT	Dynegy Marketing and Trade, LLC
DPC	Dynegy Power, LLC
DYPM	Dynegy Power Marketing Inc.
EBITDA	Earnings before interest, taxes, depreciation and amortization

1

EEI	Electric Energy, Inc.
EGUs	Electric generating units
EMA	Energy Management Agency Services Agreement
EMT	Executive Management Team
EPA	Environmental Protection Agency
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles of the United States of America
Genco	Illinois Power Generating Company (formerly known as Ameren Energy Generating Company)
GHG	Greenhouse Gas
HAPs	Hazardous air pollutants, as defined by the Clean Air Act
IBEW	International Brotherhood of Electrical Workers
ICAP	Installed capacity
ICC	Illinois Commerce Commission
IFRS	International Financial Reporting Standards
IMA	In-market Asset Availability
IPH	Illinois Power Holdings, LLC
IPM	Illinois Power Marketing Company (formerly known as Ameren Energy Marketing Company)
IPR	Illinois Power Resources, LLC (formerly known as New Ameren Energy Resources, LLC)
IPCB	Illinois Pollution Control Board
IPGC	Illinois Power Generating Company (formerly Ameren Energy Generating Company)
IPRG	Illinois Power Resources Generating, LLC (formerly known as New AERG, LLC)
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	Kilowatt
LC	Letter of Credit
LGE	Louisville Gas and Electric Company
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Pricing
LSTC	Liabilities Subject to Compromise
MGGA	Midwest Greenhouse Gas Accord
MGGRP	Midwestern Greenhouse Gas Reduction Program
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	One Million British Thermal Units
MRTU	Market Redesign and Technology Update
MSCI	Morgan Stanley Capital International
MW	Megawatts
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NGX	Natural Gas Exchange Inc.
NOL	Net operating loss

NO_x	Nitrogen oxide
NPDES	National Pollutant Discharge Elimination System

2

NRG	NRG Energy, Inc.
NSPS	New Source Performance Standard
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OTC	Over-the-counter
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PRB	Powder River Basin
PRIDE	Producing Results through Innovation by Dynegy Employees
PSA	Power Supply Agreements
PSD	Prevention of Significant Deterioration
PURPA	The Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RACT	Reasonably Available Control Technology
RCRA	The Resource Conservation and Recovery Act of 1976, as amended
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SACCWIS	Statewide Advisory Committee on Cooling Water Intake Structures
SCE	Southern California Edison
SCR	Selective Catalytic Reduction
SEC	U.S. Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPDES	State Pollutant Discharge Elimination System
TVA	Tennessee Valley Authority
VaR	Value at Risk
VIE	Variable Interest Entity
VLGC	Very Large Gas Carrier
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

Item 1. Business

THE COMPANY

Dynegy began operations in 1984 and became incorporated in the State of Delaware in 2007. We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our primary business is the production and sale of electric energy, capacity and ancillary services from our fleet of 16 power plants in six states totaling approximately 13,200 MW of generating capacity.

We operate a portfolio of generation assets that is diversified in terms of dispatch profile, fuel type and geography. Our Coal and IPH segments are fleets of baseload coal facilities, located in Illinois, that dispatch around the clock throughout the year. Our Gas segment operates both intermediate and peaking natural gas plants, located in the Midwest, Northeast and California. The inherent cycling and dispatch characteristics of our intermediate combined cycle units allow us to take advantage of the volatility in market pricing in the day-ahead and hourly markets. This flexibility allows us to optimize our assets and provide incremental value. Peaking facilities are generally dispatched to serve load only during the highest periods of power demand, such as hot summer and cold winter days. In addition to generating power, our generating facilities also receive capacity revenues through structured markets or bilateral tolling agreements, as local utilities and ISOs seek to ensure sufficient generation capacity is available to meet future market demands.

We sell electric energy, capacity and ancillary services primarily on a wholesale basis from our power generation facilities. In connection with the AER Acquisition on December 2, 2013, we began serving residential, municipal, commercial and industrial customers through our Homefield Energy retail business in Illinois. Wholesale electricity customers will, for reliability reasons and to meet regulatory requirements, contract for rights to capacity from generating units. Ancillary services are the products of a power generation facility that support the transmission grid operation, follow real-time changes in load and provide emergency reserves for major changes to the balance of generation and load. Retail electricity customers purchase energy and these related services in the deregulated retail energy market. We sell these products individually or in combination to our customers for various lengths of time from hourly to multi-year transactions.

We do business with a wide range of customers, including RTOs and ISOs, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, power marketers, financial participants such as banks and hedge funds and residential, commercial and industrial end-users. Some of our customers, such as municipalities or integrated utilities, purchase our products for resale in order to serve their retail, commercial and industrial customers. Other customers, such as some power marketers, may buy from us to serve their own wholesale or retail customers or as a hedge against power sales they have made.

Our principal executive office is located at 601 Travis Street, Suite 1400, Houston, Texas 77002, and our telephone number is (713) 507-6400. We file annual, quarterly and current reports, and other information with the SEC. You may read and copy any document we file at the SEC's Public Reference Room at 100 F Street N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC's Public Reference Room. Our SEC filings are also available to the public at the SEC's website at www.sec.gov. No information from such website is incorporated by reference herein. Our SEC filings are also available free of charge on our website at www.dynegy.com, as soon as reasonably practicable after those reports are filed with or furnished to the SEC. The contents of our website are not intended to be, and should not be considered to be, incorporated by reference into this Form 10-K.

Our Power Generation Portfolio

Our generating facilities are as follows:

Facility	Total Net Generating Capacity (MW)(1)	Primary Fuel Type	Dispatch Type	Location	Region
Baldwin	1,800	Coal	Baseload	Baldwin, IL	MISO
Havana (2)	441	Coal	Baseload	Havana, IL	MISO
Hennepin	293	Coal	Baseload	Hennepin, IL	MISO
Wood River (3)	446	Coal	Baseload	Alton, IL	MISO
Total Coal Segment	2,980				
Coffeen	915	Coal	Baseload	Montgomery County, IL	MISO
Joppa/EEI (4)	802	Coal	Baseload	Joppa, IL	MISO
Newton	1,225	Coal	Baseload	Jasper County, IL	MISO
Duck Creek	425	Coal	Baseload	Canton, IL	MISO
E.D. Edwards	695	Coal	Baseload	Bartonville, IL	MISO
Total IPH Segment	4,062				
Moss Landing Units 1-2	1,020	Gas	Intermediate	Monterey County, CA	CAISO
Units 6-7	1,509	Gas	Peaking	Monterey County, CA	CAISO
Kendall	1,200	Gas	Intermediate	Minooka, IL	PJM
Ontelaunee	580	Gas	Intermediate	Ontelaunee Township, PA	PJM
Oakland	165	Oil	Peaking	Oakland, CA	CAISO
Casco Bay	540	Gas	Intermediate	Veazie, ME	ISO-NE
Independence	1,064	Gas	Intermediate	Scriba, NY	NYISO
Black Mountain (5)	43	Gas	Baseload	Las Vegas, NV	WECC
Total Gas Segment	6,121				
Total Fleet Capacity	13,163				

(1) Unit capabilities are based on winter capacity. We have not included the Stallings and Oglesby facilities, consisting of approximately 150 MW that were historically included in our Coal segment, as these facilities were retired effective January 7, 2013. We also have not included the Morro Bay facility, as it is currently retired and is out of operation, effective February 5, 2014. Additionally, we have not included the DNE facilities, consisting of approximately 1,700 MW, as these facilities were deconsolidated effective October 1, 2012, and were sold during 2013. Please read Note 23—Dispositions and Discontinued Operations for further discussion of the sale of the DNE facilities.

(2) Represents Unit 6 generating capacity. Units 1-5, with a combined net generating capacity of 228 MW, are retired and out of operation.

(3) Represents Units 4 and 5 generating capacity. Units 1-3, with a combined net generating capacity of 119 MW, are retired and out of operation.

(4) We indirectly own an 80 percent interest in this facility. Total output capacity of this facility is 1,002 MW. Additionally, Joppa has 235 MW of natural gas-fired capacity which is currently not operating and therefore excluded from the table above.

(5) We indirectly own a 50 percent interest in this facility. Total output capacity of this facility is 85 MW.

Business Strategy

Our business strategy is to create value through the optimization of the Company's generation facilities, cost structure and financial resources. We manage our generation assets by fuel type with three primary reportable segments: (i) the Coal segment (“Coal”), (ii) the IPH segment (“IPH”) and (iii) the Gas segment (“Gas”).

Our strategic plan is aimed at mitigating our challenges and leveraging our strengths in order to maximize returns to shareholders and deliver quality products, services and experiences to our customers and stakeholders. There are three primary pillars to our strategy:

- Customer Focus—We focus on understanding the needs of our customers and stakeholders and delivering solutions that exceed expectations;
- Continuous Improvement—We are committed to the pursuit of quality, efficiency and flexibility throughout our business; and
- Capital Structure Management and Allocation—We will create a sustainable and flexible capital structure with diversified liquidity sources to efficiently support and allocate resources across our business activities.

Customer Focus. Our commercial outreach focuses on the needs of the communities we serve, the end-use and wholesale customer, our market channel partners and the government agencies and regulatory bodies that represent the public interest. The insight provided through these relationships will drive decisions that meet customer needs while optimizing the value of our business.

Currently, our commercial strategy seeks to optimize the value of our assets by locking in near-term cash flow while preserving the ability to capture higher values longer-term as power markets improve. We may hedge portions of the expected output from our facilities over a one- to three-year time frame with the goal of stabilizing near-term earnings and cash flow while preserving upside potential should commodity prices or market factors improve. The wholesale origination and trading and retail marketing teams are responsible for implementation of this strategy. These teams provide access to a broad portfolio of customers with varying energy and capacity requirements. There is a significant risk reduction effect from linking our generation to our customer load which reduces the need to purchase hedging products in the market.

Our wholesale origination and trading efforts focus on marketing energy and services through structured transactions that are designed to meet our customers' operating, financial and risk requirements while simultaneously compensating Dynegy appropriately for the products and services delivered. Additionally, we seek to capture the intrinsic and extrinsic value of our generation portfolios. We utilize a wide range of products and contracts such as tolling agreements, fuel supply contracts, capacity auctions, bilateral capacity contracts, power and natural gas swap agreements, power and natural gas options and other financial instruments. The retail marketing effort focuses on offering end-use customers energy products that range from fixed price and full requirements to flexible price and volume structures. Our goal is to deliver value beyond price by leveraging our experience in the energy markets and sharing our expertise to help customers make sound energy decisions. Establishing and maintaining strong relationships with retail energy channel partners is another key focus where personal service and transparent communication

6

further build the Homefield Energy brand as a trusted supplier. Our objective is to maximize the benefit to both Dynegy and our customers by linking our generation to the load we serve.

Dynegy operates in a complex and highly-regulated environment with multiple federal, state and local stakeholders, such as legislators, government agencies, industry groups, consumers and environmentalists. These stakeholders are important partners and exhibit influence over regulators and their decisions. Dynegy works with these stakeholders to encourage reasonable regulations that increase shareholder value through driving revenue and containing costs. Our regulatory strategy includes a continuous process of advocacy, visibility, education and building alliances. We also focus on the key issues that most affect our business. The ultimate goal is to find solutions that provide adequate cost recovery and incent investment, while providing safe, reliable, cost-effective and environmentally-compliant generation for the communities in which we operate.

Continuous Improvement. We have historically achieved strong plant operations and are committed to operating all of our facilities in a safe, reliable, cost-efficient and environmentally compliant manner. We have dedicated significant resources toward these priorities with approximately $1 billion invested since 2005 in our Coal segment for environmental compliance initiatives to meet contractual obligations and state and federal environmental standards. In addition, we continue to invest across all segments to maintain and improve the safety, reliability and efficiency of the fleet. The alignment of our segments by fuel type helps facilitate and realize best operating practices across the respective portfolios, leading to additional cost efficiencies and improved operating practices. Still further, we have recently centralized our operations support function with the primary focus on instilling various cost and operating best practices across the fleets in the areas of safety, procurement, engineering and outage management.

During 2013, we continued to employ our cost and performance improvement initiative, known as PRIDE, which is designed to drive recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency. For 2013, we recognized $39 million in operating margin and cost improvements and $191 million in incremental liquidity from balance sheet improvements due to PRIDE initiatives. In 2014, we are targeting additional margin and cost improvements of $60 million, and additional balance sheet improvements of $65 million, inclusive of the newly acquired IPH segment.

Capital Structure Management and Allocation. The power industry is a cyclical commodity business with significant price volatility requiring considerable ongoing capital investment. As such, it is imperative to build and maintain a balance sheet with manageable debt levels supported by a flexible and diverse liquidity program. Our long-term debt and lease obligations were restructured during 2012 through the Chapter 11 process and we emerged from bankruptcy with a leverage profile designed to withstand protracted low commodity price environments and provide the necessary liquidity to support daily operations. Additionally, during the second quarter 2013, we refinanced our credit facilities to take advantage of lower interest rates and established a new $475 million parent company revolver. Our ongoing capital allocation priorities, first and foremost, are to support the daily business requirements, including making the necessary capital investments to maintain safety and reliability of our fleet and to comply with environmental rules and regulations. Additional capital allocation options that are evaluated include debt management, investments in our existing portfolio, potential acquisitions and returning capital to shareholders. Capital allocation decisions are based on the alternatives that provide the highest risk-adjusted rates of return.

We continue to focus on building a diverse liquidity program to support our ongoing operations and commercial activities. This includes building cash balances, expanding our first lien collateral program to include additional hedging counterparties and entering into the Credit Agreement. We will continue to look at other measures to best manage our balance sheet as well as seek additional sources of liquidity.

Recent Developments

On December 2, 2013, we completed the acquisition of New Ameren Energy Resources, LLC (“AER”) and its subsidiaries (the “AER Acquisition”). In connection with the AER Acquisition, Ameren retained certain historical obligations of AER and its subsidiaries, including certain historical environmental and tax liabilities. Genco’s approximately $825 million in aggregate principal amount of notes remain outstanding as an obligation of Genco. Additionally, Ameren is required to maintain its existing credit support, including all of its collateral obligations with respect to IPM, for approximately two years following closing. The acquisition added 4,062 MW of generation in Illinois and also included the Homefield Energy retail business. We acquired AER and its subsidiaries through IPH, which will maintain corporate separateness from Dynegy and our other legal entities outside of IPH. There was no cash consideration or stock issued as part of the purchase price.

On October 10, 2013, Dynegy and SCE agreed to resolve prior contract termination disputes by entering into two new transactions. The pending arbitration and federal court litigation have been dismissed as a result of the new transactions. Under the first transaction, SCE agreed to purchase energy and capacity from our Moss Landing Energy Facility for 2014 and 2015. Under the second transaction, SCE agreed to purchase energy and capacity from the same facility for 2016. The 2016 transaction is conditioned on approval by the CPUC, which both SCE and Dynegy have agreed to seek in good faith and use commercially reasonable efforts to obtain. On November 27, 2013, SCE filed the necessary request for the CPUC's approval of the 2016 transaction. The request is currently being reviewed by the CPUC's Energy Division.

MARKET DISCUSSION

Our business operations are focused primarily on the wholesale power generation sector of the energy industry. We manage and report the results of our power generation business within three segments on a consolidated basis: (i) Coal, (ii) IPH and (iii) Gas. We continue to expect that, over the longer-term, power pricing will improve as natural gas prices increase, marginal generating units retire, and more stringent environmental regulations force the retirement of power generation units that have not invested in environmental upgrades. As a result, we expect our coal-fired baseload fleets are positioned to benefit from higher power and capacity prices in the Midwest. We also expect these same factors will benefit our combined cycle units throughout the country through increased run-times and higher power prices as heat rates expand resulting in improved margins and cash flows.

NERC Regions, RTOs and ISOs. In discussing our business, we often refer to NERC regions. The NERC and its regional reliability entities were formed to ensure the reliability and security of the electricity system. The regional reliability entities set standards for reliable operation and maintenance of power generation facilities and transmission systems. For example, each NERC region establishes a minimum operating reserve requirement to ensure there is sufficient generating capacity to meet expected demand within its region. Each NERC region reports seasonally and annually on the status of generation and transmission in such region.

Separately, RTOs and ISOs administer the transmission infrastructure and markets across a regional footprint in most of the markets in which we operate. They are responsible for dispatching all generation facilities in their respective footprints and are responsible for both maximum utilization and reliable and efficient operation of the transmission system. RTOs and ISOs administer energy and ancillary service markets in the short term, usually day-ahead and real-time markets. Several RTOs and ISOs also ensure long-term planning reserves through monthly, semi-annual, annual and multi-year capacity markets. The RTOs and ISOs that oversee most of the wholesale power markets in which we operate currently impose, and will likely continue to impose, both bid and price limits. They may also enforce caps and other mechanisms to guard against the exercise of market dominance in these markets. NERC regions and RTOs/ISOs often have different geographic footprints, and while there may be geographic overlap between NERC regions and RTOs/ISOs, their respective roles and responsibilities do not generally overlap.

In RTO and ISO regions with centrally dispatched market structures, all generators selling into the centralized market receive the same price for energy sold based on the bid price associated with the production of the last MWh that is needed to balance supply with demand within a designated zone or at a given location (different zones or locations within the same RTO/ISO may produce different prices respective to other zones within the same RTO/ISO due to transmission losses and congestion). For example, a less efficient and/or less economical natural gas-fired unit may be needed in some hours to meet demand. If this unit's production is required to meet demand on the margin, its bid price will set the market clearing price that will be paid for all dispatched generation in the same zone or location (although the price paid at other zones or locations may vary because of transmission losses and congestion), regardless of the price that any other unit may have offered into the market. In RTO and ISO regions with centrally dispatched market structures and location-based marginal price clearing structures (e.g. PJM, NYISO, MISO, CAISO and ISO-NE), generators will receive the location-based marginal price for their output. The location-based marginal price, absent congestion, would be the marginal price of the most expensive unit needed to meet demand. In regions that are outside the footprint of RTOs/ISOs, prices are determined on a bilateral basis between buyers and sellers.

Reserve Margins. RTOs and ISOs are required to meet NERC planning and resource adequacy standards. The reserve margin, which is the amount of generation resources in excess of peak load, is a measure of resource adequacy and is also used to assess the supply-demand balance of a region. RTOs and ISOs use various mechanisms to help market participants meet their planning reserve margin requirements. Mechanisms range from centralized capacity markets administered by the ISO to unstructured markets where entities fulfill their requirements through a combination of long and short-term bilateral contracts between individual counterparties and self-generation.

Coal and IPH Segments

Our Coal segment is comprised of four operating coal-fired power generation facilities in Illinois with a total generating capacity of 2,980 MW. Our IPH segment is comprised of five operating coal-fired power generation facilities located in Illinois with a total owned generating capacity of 4,062 MW.

RTO/ISO Discussion

MISO. The MISO market includes all of Wisconsin and portions of Michigan, Kentucky, Indiana, Illinois, Missouri, Arkansas, Mississippi, Texas, Louisiana, Iowa, Minnesota, North Dakota, Montana and Manitoba, Canada.

The MISO energy market is designed to ensure that all market participants have open-access to the transmission system on a non-discriminatory basis. MISO, as an independent RTO, maintains functional control over the use of the transmission system to ensure transmission circuits do not exceed their secure operating limits and become overloaded. MISO operates day-ahead and real-time energy markets using a LMP system which calculates a price for every generator and load point within MISO. This market is transparent, allowing generators and load serving entities to see real-time price effects of transmission constraints and the impacts of congestion at each pricing point. An independent market monitor is responsible for evaluating the performance of the markets and identifying conduct by market participants or MISO that may compromise the efficiency or distort the outcome of the markets.

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

MISO’s annual Loss of Load Expectation (“LOLE”) study was published in early November 2013. The LOLE study is a critical input to the annual MISO Planning Resource Auction (“PRA”). The LOLE study employed meaningful changes for the planning year 2014-2015 to reflect the integration of Entergy into MISO and to reflect modeling enhancements required to stabilize the planning reserve margin and reliability requirements in MISO. The LOLE also utilizes a revised methodology to calculate import and export capabilities between Local Resource Zones (“LRZ”) which may have an impact on intra-zonal balances. On February 6, 2014, MISO announced revisions to its November 2013 LOLE analysis. These revisions impacted LRZ 4 and 5 (where our facilities are located).

MISO also administers an FTR market holding monthly and annual auctions. FTRs allow users to manage the cost of transmission congestion (as measured by LMP differentials, between source and sink points on the transmission grid) and corresponding price differentials across the market area.

MISO implemented the Ancillary Services Market (Regulation and Operating Reserves) on January 6, 2009 and implemented an enforceable Planning Reserve Margin for each planning year effective June 1, 2009. A feature of the Ancillary Services Market is the addition of scarcity pricing that, during supply shortages, can raise the combined price of energy and ancillary services significantly higher than the previous cap of $1,000/MWh.

Contracted Capacity and Energy

We commercialize our Coal and IPH segment assets through a combination of physical participation in the MISO markets (as described above), bilateral physical and financial power sales and fuel and capacity contracts.

Reserve Margins

The MISO Summer 2013 projected Planning Reserve Margin was 28 percent with a 14 percent Planning Reserve Margin requirement based on a projected summer peak of 91,532 MW. The actual peak load was recorded on July 18, 2013 at 95,777 MW. This translates to an actual reserve margin of 22.4 percent indicating MISO met its Planning Reserve Margin requirement of 14 percent, which suggests, given the normal summer load conditions; MISO had a surplus of capacity in 2013. In 2012, the projected Planning Reserve Margin was 27 percent, while the Planning Reserve Margin requirement was 17 percent and given the heat wave experienced in 2012, the actual reserve margin was close to the Planning Reserve Margin requirement.

Gas Segment

Our Gas segment is comprised of six operating natural gas-fired power generation facilities located in California, Nevada, Illinois, Pennsylvania, New York, and Maine and one fuel-oil fired power generation facility located in California, totaling 6,121 MW of electric generating capacity. We filed to retire our 650 MW Morro Bay facility on November 7, 2013 and this retirement was effective February 5, 2014.

RTO/ISO Discussion

PJM. The PJM market includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Our Kendall and Ontelaunee facilities, located in Illinois and Pennsylvania, respectively, operate in PJM with an aggregate net generating capacity of 1,780 MW.

PJM administers markets for wholesale electricity and provides transmission planning for the region, utilizing the LMP system described above. PJM operates day-ahead and real-time markets into which generators can bid to provide energy and ancillary services. PJM also administers markets for capacity. An independent market monitor continually monitors PJM markets to ensure a robust, competitive market and to identify any improper behavior by any entity. PJM implemented a forward capacity auction in 2007, the RPM, which established long-term markets for capacity. In addition to entering into bilateral capacity transactions, we have participated in RPM base residual auctions for years up to and including PJM's planning year 2016-2017, which ends May 31, 2017, as well as ongoing incremental auctions to balance positions and offer residual capacity that may become available.

PJM, like MISO, dispatches power plants to meet system energy and reliability needs, and settles physical power deliveries at LMPs. This value is determined by an ISO-administered auction process, which evaluates and selects the least cost supplier offers to create reliable and least-cost dispatch. The ISO-administered LMP energy markets consist of two separate and characteristically distinct settlement time frames. The first is a security-constrained, financially firm, day-ahead unit commitment market. The second is a security-constrained, financially-settled, real-time dispatch and balancing market. Prices paid in these LMP energy markets, however, are affected by, among other things, (i) market mitigation measures, which can result in lower prices associated with certain generating units that are mitigated because they are deemed to have the potential to exercise locational market power, and (ii) the existing $1,000/MWh energy market price caps that are in place.

NYISO. The NYISO market includes the entire state of New York. Capacity pricing is calculated as a function of NYISO's annual required reserve margin, the estimated net cost of "new entrant" generation, estimated peak demand and the actual amount of capacity bid into the market at or below the demand curve. The demand curve mechanism provides for incrementally higher capacity pricing at lower reserve margins, such that "new entrant" economics become attractive as the reserve margin approaches required minimum levels. The intent of the demand curve mechanism is to ensure that existing generation facilities have enough revenue to recover their investment when capacity revenues are coupled with energy and ancillary service revenues. Additionally, the demand curve mechanism is intended to attract new investment in generation when and where that new capacity is needed most. To calculate the price and quantity of installed capacity, four ICAP demand curves are utilized: one for Long Island, one for New York City and one for Statewide (commonly referred to as Rest of State). The fourth demand curve will cover the recently approved Lower Hudson Valley Zone beginning in May 2014. Our Independence facility operates in the Rest of State market with an aggregate net generating capacity of 1,064 MW. NYISO also dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Due to transmission constraints, energy prices vary across New York and are generally higher in the Southeastern part of New York, New York City and Long Island. Our Independence facility is located in the Northwestern part of the state.

ISO-NE. The ISO-NE market includes the six New England states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. ISO-NE also dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Much like regional zones in the NYISO, energy prices also vary among the participating states in ISO-NE, and are largely influenced by transmission constraints and fuel supply. ISO-NE implemented a FCM in June 2010, where capacity prices are determined through auctions. Our Casco Bay facility, located in Maine, operates in ISO-NE with an aggregate net generating capacity of 540 MW. ISO-NE recently implemented changes to FCM starting in FCA-8, covering the 2017-2018 capacity year. Changes include removal of the price floor and implementation of a minimum offer price rule for new resources to prevent buy-side market power. On October 17, 2013, ISO-NE issued a memorandum to market participants noting a potential resource shortfall based on submitted retirement requests. FCA-8 occurred on February 3, 2014. The auction cleared at a price of $15/kW-month. However, due to recent capacity retirements, the "insufficient competition" clause in the ISO-NE tariff was triggered. Under the insufficient competition clause, existing generation in rest-of-pool (including Casco Bay) received an administrative cap price of $7.025/kW-month. Potentially impacting FCA-9, covering the 2018-2019 planning year, ISO-NE was ordered to submit a proposal for a downward sloping demand curve to the FERC by April 1, 2014. Also potentially impacting FCA-9, competing proposals from ISO-NE and New England Power Pool regarding "performance incentive" measures have been filed with the FERC.

CAISO. CAISO covers approximately 90 percent of the State of California and operates a centrally cleared market for energy and ancillary services. Energy is priced at each location utilizing the LMP system described above. This market structure was implemented in April 2009 as part of the MRTU. Currently the CAISO has a mandatory resource adequacy requirement but no centrally-administered capacity market. The Oakland facility has been designated as an RMR unit by the CAISO for 2014. Our Moss Landing and Oakland facilities operate in CAISO with an aggregate net generating capacity of 2,694 MW.

Contracted Capacity and Energy

PJM. Our generation assets in PJM are natural gas-fired, combined-cycle, intermediate-dispatch facilities. We commercialize these assets through a combination of bilateral power, fuel and capacity contracts. We commercialize our capacity through either the RPM auction or on a bilateral basis. Our Kendall facility has one tolling agreement for 85 MW that expires in 2017.

NYISO. At our Independence facility, 740 MW of capacity is contracted under a capacity sales agreement that runs through 2014. Revenue from this capacity obligation is largely fixed with a variable discount that varies each month based on the applicable LMP. Additionally, we supply steam and up to 44 MW of electric energy from our Independence facility to a third party at a fixed price. Due to the standard capacity market operated by NYISO and liquid over-the-counter market for NYISO capacity products, we are able to sell substantially all of the Independence facility's remaining uncommitted capacity into the market.

ISO-NE. Our Casco Bay facility sells capacity through the forward capacity auctions administered by the ISO-NE. Eight forward capacity auctions have been held to date. All auctions through the seventh auction cleared at the floor price due to oversupply of capacity in the region, with the low price being $2.95 kW/month for the 2013-2014 market period. For the eighth auction, the floor price was removed. However, the auction cleared at a new high mark of $15/kW-month due to significant capacity requirements in the region. Due to the "insufficient competition" clause in the ISO-NE tariff, existing generation received an administrative cap price of $7.025/kW-month.

CAISO. In CAISO, where our assets include intermediate dispatch and peaking facilities, we seek to mitigate spark spread variability through RMR, tolling arrangements and physical and financial bilateral power and fuel contracts. All of the capacity of our Moss Landing Units 6 and 7 was contracted under tolling arrangements through 2013. As previously noted, our Oakland facility operates under an RMR contract with the CAISO.

WECC. We have a 50 percent indirect ownership interest in the Black Mountain facility, which is a PURPA QF located near Las Vegas, Nevada, in the WECC. Capacity and energy from this facility are sold to Nevada Power Company under a long-term PURPA QF contract that expires in 2023.

Reserve Margins

PJM. The installed reserve margin requirement is reviewed by PJM on an annual basis and has been in the 15.6 percent to 15.9 percent range for the Planning Years 2012-2013 to 2013-2014. The actual reserve margin based on deliverable capacity was 29.4 percent for Planning Year 2013-2014, which is 13.5 percentage points above the required installed reserve margin.

NYISO. A reserve margin of 17 percent has been accepted by FERC for the New York Control Area for the period beginning May 1, 2013 and ending April 30, 2014. A reserve margin of 17 percent for the period beginning May 1, 2014 and ending April 30, 2015 has been filed and is being reviewed at FERC. The actual amount of installed capacity is approximately 3 percentage points above NYISO's current required reserve margin.

ISO-NE. Similar to PJM, ISO-NE will publish on an annual basis the required reserve margin which is called Installed Capacity Requirement ("ICR"). For the 2014-2015 planning period, it is 18.7 percent, including capacity imported from Hydro Quebec (HQICC). This is approximately 1.5 percent higher than the previous planning period, which indicates a growing need for reserves. Actual installed reserve margin is approximately 36.6 percent, which is 17.9 percentage points above the ICR.

Recommended improvements and modifications to the forward capacity market design are currently in litigation at FERC, and discussions to address improvements to the forward capacity market design are currently underway by the ISO and its stakeholders. Beginning with the 2017-2018 commitment year, the floor price in the capacity market was removed. Recent retirement announcements, as well as the reduction in demand response, have resulted in higher capacity prices.

CAISO. The CPUC requires a resources adequacy margin of 15 to 17 percent. As of the latest summer assessment for the region in May 2013, the reserve margin was approximately 20.4 percent. Unlike other centrally cleared capacity markets, the CAISO resource adequacy market is a bilaterally traded market which typically transacts in monthly products as opposed to annual capacity products in other regions. On the state level, there are numerous ongoing market initiatives that impact wholesale generation, principally the development of resource adequacy rules and capacity markets to include the necessary flexibility to integrate the state-mandated 33 percent renewable resources and maintain reliability of the grid. The CPUC has integrated flexible capacity into the 2014 Resource Adequacy procurement requirements and both the CPUC and CAISO recently approved a plan to examine multi-year procurement requirements that will bridge the gap between Resource Adequacy (one-year) and Long Term Power Procurement (ten-year) plans.

Other

Market-Based Rates. Our ability to charge market-based rates for wholesale sales of electricity, as opposed to cost-based rates, is governed by FERC. We have been granted market-based rate authority for wholesale power sales from our EWG facilities, as well as wholesale power sales by our power marketing entities, DYPM, DMT and IPM. The Dynegy EWG facilities include all of our facilities except our investment in the Nevada Cogeneration Associates #2 (“Black Mountain”) facility. This facility is known as a QF, and has various exemptions from federal regulation and sells electricity directly to purchasers under negotiated and previously approved power purchase agreements.

Every three years, FERC conducts a review of our market-based rates and potential market power on a regional basis (known as the triennial market power review). In 2013, we filed a market power update with FERC for our CAISO assets.

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 systems in place in order to monitor our swap activity and comply with Non-Swap Dealer/Major Swap Participant reporting requirements. As required, Dynegy is meeting its reporting obligations under Parts 43, 45 and 46 of the CFTC’s regulations, which cover real-time public reporting of swap transaction data, reporting of swap transaction data to a registered swap data repository and reporting of historical swaps. We continue to monitor the CFTC’s releases for guidance on these rules and any other clearing and reporting requirements that will be required of our business or impact current operations. On November 5, 2013, the CFTC voted in favor of putting new proposals on position limits and aggregation out for public comment. The two new notices of proposed rulemaking constitute the re-proposal of federal aggregate position limits rules that were previously finalized under Dodd-Frank and vacated by a federal court in September 2012.

ENVIRONMENTAL MATTERS

Our business is subject to extensive federal, state and local laws and regulations concerning environmental matters, including the discharge of materials into the environment. We are committed to operating within these laws and regulations and to conducting our business in an environmentally responsible manner. The environmental, legal and regulatory landscape is subject to change and has become more stringent over time. The process for acquiring or maintaining permits or otherwise complying with applicable rules and regulations may create unprofitable or unfavorable operating conditions or require significant capital and operating expenditures. Further, changing interpretations of existing regulations may subject historical maintenance, repair and replacement activities at our facilities to claims of noncompliance.

The following is a summary of (i) the material federal, state and local environmental laws and regulations applicable to us and (ii) certain pending judicial and administrative proceedings related thereto. Compliance with these environmental laws and regulations and resolution of these various proceedings may result in increased capital expenditures and other environmental compliance costs, increased operations and maintenance expenses, increased AROs, and the imposition of fines and penalties, any of which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, if we are required to incur significant additional costs or expenses to comply with applicable environmental laws or to resolve a related proceeding, the incurrence of such costs or expenses may render continued operation of a plant uneconomical such that we may determine, subject to applicable laws and any applicable financing or other agreements, to reduce the plant’s operations to minimize such costs or expenses or cease to operate the plant completely to avoid such costs or expenses. Unless otherwise expressly noted in the following summary, we are not currently able to reasonably estimate the costs and expenses, or range of the costs and expenses, associated with complying with these environmental laws and regulations or with resolution of these judicial and administrative proceedings. For additional information regarding our pending environmental judicial and administrative proceedings, please read Note 16—Commitments and Contingencies for further discussion.

Our aggregate Coal segment expenditures (both capitalized and those included in operating expense) for compliance with laws and regulations related to the protection of the environment were approximately $25 million in 2013, compared to approximately $85 million in 2012. Because we completed the environmental compliance capital requirements for the Coal segment's Consent Decree (which is defined and discussed below) in November 2012, the 2013 expenditures included only approximately $2 million related to the Consent Decree. We estimate that our Coal segment’s total expenditures for environmental compliance in 2014 will be approximately $35 million, with approximately $10 million in capital expenditures and $25 million in operating expenses.

We estimate that our IPH segment's total expenditures for environmental compliance in 2014 will be approximately $55 million, with approximately $25 million in capital expenditures and $30 million in operating expenses.
Our aggregate Gas segment expenditures for environmental compliance were approximately $5 million in 2013. We estimate that our Gas segment’s total expenditures for environmental compliance in 2014 will be approximately $10 million in operating expenses.

The Clean Air Act

The CAA and comparable state laws and regulations relating to air emissions impose responsibilities on owners and operators of sources of air emissions, including requirements to obtain construction and operating permits as well as compliance certifications and reporting obligations. The CAA requires that fossil-fueled electric generating plants have sufficient emission allowances to cover actual SO_2 emissions and in some regions NO_x emissions, and that they meet certain pollutant emission standards as well.

In order to ensure continued compliance with the CAA and related rules and regulations, we have installed emission reduction technology at our Coal segment facilities. Our Baldwin and Havana facilities have installed and are operating dry flue gas desulfurization systems for the control of SO_2 emissions, and electrostatic precipitators and baghouses for the control of particulate matter emissions. Our Hennepin facility has electrostatic precipitators and baghouses for the control of particulate matter. The baghouses at our Coal segment facilities also control hazardous air pollutants in particulate form, such as most metals. Activated carbon injection or mercury oxidation systems for the control of mercury emissions have been installed and are operating on all of our Coal segment's coal-fired capacity. SCR technology to control NO_x emissions has been installed and has been operating at Havana and two units at Baldwin for several years; the remaining Coal segment units use low-NO_x burners and overfire air to lower NO_x emissions. All of our Coal segment facilities also use low sulfur coal.

At our IPH segment facilities, Duck Creek and Coffeen operate wet flue gas desulfurization systems and burn primarily low sulfur coal for the control of SO_2 emissions and operate electrostatic precipitators for the control of particulate emissions. The other IPH coal-fired facilities also operate electrostatic precipitators to control particulate emissions and use low sulfur coal exclusively. SCR technology to control NO_x emissions has been installed and has been operating at Coffeen, Duck Creek and Edwards Unit 3; the remaining IPH units use low-NO_x burners and overfire or separated overfire air to lower NO_x emissions, except Joppa Unit 2 which uses low-NO_x burners. Refined coal is also currently used to lower NO_x emissions at the Joppa, Newton, Coffeen and Duck Creek facilities and is expected to be used at the Edwards facility beginning in 2014. Activated carbon injection for the control of mercury emissions has been installed and is operating on all of IPH's coal-fired capacity.

Multi-Pollutant Air Emission Initiatives

In recent years, various federal and state legislative and regulatory multi-pollutant initiatives have been introduced. In 2005, the EPA finalized the CAIR, which would require reductions of approximately 70 percent each in emissions of SO_2 and NO_x by 2015 from coal-fired power generation units across the eastern U.S. The CAIR was challenged by several parties and ultimately remanded to the EPA by the U.S. Court of Appeals for the District of Columbia Circuit. The CAIR remained in effect in 2013 and, as a result of a court order staying the CAIR's intended replacement rule (i.e. the CSAPR), the CAIR will continue in effect at least until the judicial challenges to the CSAPR are resolved. Our coal-fired facilities in Illinois are subject to state SO_2 and NO_x limitations more stringent than those imposed by the CAIR.

Cross-State Air Pollution Rule. In July 2011, the EPA issued its final rule on Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (the "Cross-State Air Pollution Rule," formerly known as the Transport Rule). Numerous petitions for judicial review of the CSAPR were filed and, on December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued an order staying implementation of the CSAPR. In response, the EPA reinstated the CAIR pending judicial review. In August 2012, the court vacated the CSAPR and ordered the EPA to continue administering the CAIR pending the promulgation of a valid replacement rule. In June 2013, the U.S. Supreme Court granted petitions to review the appellate court's decision vacating the CSAPR. The Court is expected to issue its decision by June 2014. We will continue to monitor rulemaking, judicial and legislative developments regarding the CSAPR and a possible replacement rule and evaluate any potential impacts on our operations.

The CSAPR is intended to reduce emissions of SO_2 and NO_x from large EGUs in the eastern half of the U.S. If the CSAPR is eventually upheld by the courts, the rule would impose cap-and-trade programs within each affected state that cap emissions of SO_2 and NO_x at levels estimated to eliminate that state's contribution to nonattainment in, or interference with maintenance of attainment status by down-wind areas with respect to the NAAQS for fine particulate matter (PM2.5) and ozone. Under the CSAPR, our generating facilities in Illinois, New York and Pennsylvania would be subject to new cap-and-trade programs capping emissions of NO_x from May 1 through September 30 and capping emissions of SO_2 and NO_x on an annual basis. The requirements applicable to SO_2 emissions from EGUs in Illinois, New York and Pennsylvania would have been implemented in two stages with existing EGUs in these states allocated fewer SO_2 emission allowances beginning in 2014.

Based on our current projections of emissions in 2014, we anticipate that our coal-fired facilities in our Coal segment and our coal-fired facilities in our IPH segment would both have an adequate number of allowances granted in 2014 under the CAIR SO_2 and NO_x (ozone season and annual) cap-and-trade programs.

Mercury/HAPs. In March 2005, the EPA issued the CAMR for control of mercury emissions from coal-fired power plants and established a cap-and-trade program requiring states to promulgate rules at least as stringent as the CAMR. In December 2006, the IPCB approved a state rule for the control of mercury emissions from coal-fired power plants that required additional capital and operating expenditures at our Illinois coal-fired plants beginning in 2007.

In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAMR; however, the Illinois mercury regulations remain in effect. In December 2011, the EPA issued its Mercury and Air Toxics Standards ("MATS") rule for EGUs, which establishes numeric emission limits for mercury, non-mercury metals (filterable particulate may be used as a surrogate), and acid gases (hydrogen chloride may be used as a surrogate, with SO_2 as an optional surrogate for coal-fired units using flue gas desulfurization; oil-fired units also would be subject to a hydrogen fluoride limit), and work practice standards for organic HAPs. Compliance would be required by April 16, 2015 (i.e. three years after the effective date of the final rule), unless an extension is granted in accordance with the CAA. Various parties have filed judicial appeals of the MATS rule.

Given the air emission controls already employed, we expect that each of our Coal segment facilities, as well as our IPH segment facilities, will be in compliance with the MATS rule emission limits without the need for significant additional investment.

Illinois MPS. In 2007, our Coal and IPH segments elected to demonstrate compliance with the Illinois Multi-Pollutant Standard ("MPS") at their respective coal-fired EGUs in Illinois. The MPS requires compliance with NO_x, SO_2 and mercury emissions limits.

As applicable to our Coal segment facilities, the MPS NO_x limits (ozone season and annual) started in 2012, the MPS SO_2 limits started in 2013 and will decline in 2015, and the MPS mercury requirements started in 2009 with the final mercury limit beginning in 2015. Our Coal segment facilities are in compliance with the MPS and already meet the final mercury limit.

IPH Variance. For the IPH facilities, the MPS imposes declining limits that started in 2009 for mercury and in 2010 for NO_x and SO_2. Compliance with the MPS' final SO_2 limit is required beginning in 2017. In September 2012, the IPCB granted Ameren Energy Resources Company a variance to extend the applicable compliance dates for MPS SO_2 emission limits through December 31, 2019, subject to certain conditions.

In May 2013, IPH and Ameren Energy Resources Company filed a request with the IPCB to transfer the September 2012 variance to IPH. The IPCB denied the request on procedural grounds but indicated that IPH could file its own request for variance relief. In July 2013, IPH, along with certain co-petitioners, filed such a petition for variance relief. In November 2013, the IPCB approved the variance petition. The variance provides additional time for economic recovery and related power price improvements necessary to support the installation of flue gas desulfurization (i.e. scrubber) systems at the Newton facility such that the IPH coal-fired fleet in Illinois can meet the MPS system-wide SO_2 limit. The IPCB approved the proposed plan to restrict the SO_2 emissions through 2014 to levels lower than those required by the MPS to offset any environmental impact from the variance. The IPCB's order also included a schedule of milestones for completion of various aspects of the installation of the Newton scrubber systems. The first milestone relates to the completion of engineering design by July 2015, while the last milestone relates to major equipment components being placed into final position on or before September 1, 2019. The variance also requires additional environmental protections in the form of enforceable commitments to cap the IPH system's SO_2 emissions by December 31, 2020, retire Edwards Unit 1 as soon as permitted by the MISO, and, during the variance period, use only low sulfur coal at the Newton, Edwards and Joppa facilities and optimize operation of the existing scrubbers at the Duck Creek and Coffeen facilities.

In January 2014, an environmental group filed a petition for review of the IPCB's November 2013 decision and order granting the variance relief in the Illinois Fourth District Appellate Court. We believe the petition for review is without merit and will defend the variance vigorously. On January 17, 2014, we filed a Motion to Dismiss. On February 24, 2014, the Fourth District Appellate Court granted our motion and dismissed the appeal. Please read Note 16—Commitments and Contingencies for further discussion.

Other Air Emission Initiatives

NAAQS. The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has established NAAQS for six such pollutants, including ozone, SO_2 and PM2.5, and is required to review periodically and, as necessary, update such standards. Each state is responsible for developing a plan (i.e. SIP) that will attain and maintain the NAAQS. These plans may result in the imposition of emission limits on our facilities.

In April 2012, the EPA designated as nonattainment with the 2008 ozone NAAQS the St. Louis-St. Charles-Farmington, Missouri-Illinois area, which includes Madison County, Illinois, the location of our Coal segment's Wood River facility. The affected multi-state area is classified as marginal nonattainment with an attainment deadline in 2015. The multi-state area has been designated as attainment with the 1997 eight-hour ozone NAAQS. The EPA is in the process of completing its ongoing five-year review of the current ozone NAAQS, which may result in a more stringent standard. Rulemaking action concerning the ozone NAAQS is not anticipated until mid- to late-2014. In December 2013, nine Northeast and Mid-Atlantic states petitioned the EPA to add nine upwind states, including Illinois, to the Ozone Transport Region in order to force those states to reduce emissions of NO_x and volatile organic compounds.

The EPA has initially designated nonattainment areas for the one-hour SO_2 NAAQS based on existing ambient monitoring data. The EPA expects to complete area designations for the one-hour SO_2 NAAQS by late December 2017 for areas that currently lack sufficient monitoring data. Areas designated nonattainment must achieve attainment no later than five years after initial designation. None of our Coal segment facilities are located in areas that were initially designated by the EPA as nonattainment with the one-hour SO_2 NAAQS. However, the area where our IPH segment's Edwards facility is located was designated nonattainment. In September 2013, Ameren Energy Resources Generating Company filed a judicial appeal challenging the EPA's one-hour SO_2 nonattainment designation of the Edwards' area. The outcome of this litigation is uncertain.

The EPA lowered the NAAQS for PM2.5 in December 2012. In response, the Illinois EPA has proposed to identify the Metro-East St. Louis area, including Madison County, the location of our Wood River facility, and Baldwin Township in Randolph County, the location of our Baldwin facility, as nonattainment with the PM2.5 NAAQS. The EPA intends to make initial nonattainment area designations by December 2014. The earliest attainment deadlines would be in approximately 2020.

In 2013, the EPA also proposed a rule that would eliminate existing exclusions in the SIPs of many states, including Illinois, for emissions during periods of startup, shutdown or malfunction. The EPA is expected to take final action on the proposal in 2014. If adopted as proposed, states would be required to modify their SIPs within 18 months.

New York NO_x RACT Rule. Stationary combustion sources must comply with New York State's revised NO_x RACT limits by July 1, 2014. Our Independence facility expects to meet the presumptive RACT limits using the facility's existing SCR technology and currently applicable, more stringent NO_x BACT emission limits.

New Source Review and Clean Air Litigation

Since 1999, the EPA has been engaged in a nationwide enforcement initiative to determine whether coal-fired power plants failed to comply with the requirements of the NSR and NSPS provisions under the CAA when the plants implemented modifications. The EPA's initiative focuses on whether projects performed at power plants triggered various permitting requirements, including the need to install pollution control equipment.

Coal Segment Consent Decree. In 2005, we settled a lawsuit filed by the EPA and the U.S. Department of Justice in the U.S. District Court for the Southern District of Illinois that alleged violations of the CAA and related federal and Illinois regulations concerning certain maintenance, repair and replacement activities at our Coal segment Baldwin generating station. A consent decree (the "Consent Decree") was finalized in July 2005. In November 2012, we finished the Baldwin Unit 2 scrubber installation, marking the completion of the environmental compliance capital requirements under the Consent Decree. We spent approximately $923 million related to these Consent Decree projects as of December 31, 2013.

IPH Segment. Commencing in 2005, the IPH facilities received a series of information requests from the EPA pursuant to Section 114(a) of the CAA. The requests sought detailed operating and maintenance history data with respect to the Coffeen, Newton, Edwards, Duck Creek and Joppa facilities. In August 2012, the EPA issued a Notice of Violation alleging that projects performed in 1997, 2006 and 2007 at the Newton facility violated PSD, Title V permitting and other requirements. We believe IPH's defenses to the allegations described in the Notice of Violation are meritorious. A recent decision by the U.S. Court of Appeals for the Seventh Circuit held that similar claims older than five years were barred by the statute of limitations. If not reversed or overturned, this decision may provide an additional defense to the allegations in the Newton facility Notice of Violation. Please read Note 16—Commitments and Contingencies for further discussion.

Edwards. In April 2013, environmental groups filed a citizen suit in the U.S. District Court for the Central District of Illinois alleging violations of opacity and particulate matter limits at our IPH segment's Edwards facility. We dispute the allegations and will defend the case vigorously. Please read Note 16—Commitments and Contingencies for further discussion.

The Clean Water Act

Cooling Water Intake Structures. Our water withdrawals and wastewater discharges are permitted under the CWA and analogous state laws. The cooling water intake structures at several of our facilities are regulated under Section 316(b) of the CWA. This provision generally requires that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impacts. These standards are developed and implemented for power generating facilities through NPDES permits or SPDES permits. Historically, standards for minimizing adverse environmental impacts of cooling water intakes have been made by permitting agencies on a case-by-case basis considering the best professional judgment of the permitting agency.

In 2004, the EPA issued the cooling water intake structures Phase II Rule, which set forth standards to implement the BTA requirements at existing facilities. The Phase II Rule was challenged by several environmental groups and in 2007 was struck down by the U.S. Court of Appeals for the Second Circuit. The court's decision remanded several provisions of the rule to the EPA for further rulemaking. In response, the EPA suspended its Phase II Rule and advised that permit requirements for cooling

15

water intake structures at existing facilities should once more be established on a case-by-case basis until a replacement rule is issued.

In accordance with the terms of an amended settlement agreement, the EPA is to issue its replacement rule for cooling water intake structures at existing facilities by April 17, 2014.

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

Other future NPDES proceedings could have a material adverse 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 are great enough to render the operation of any 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.

California Water Intake Policy. The California State Water Board adopted its Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (the "Policy") in May 2010. The Policy requires that existing power plants: (i) reduce their water intake flow rate to a level commensurate with that which can be achieved by a closed cycle cooling system or (ii) if it is not feasible to reduce the water intake flow rate to this level, reduce impingement mortality and entrainment to a level comparable to that achieved by such a reduced water intake flow rate using operational or structural controls, or both. Compliance with the Policy would be required at our Gas segment's Moss Landing facility by December 31, 2017.

In September 2010, the State Water Board proposed to amend the Policy to allow an owner or operator of a power plant with previously installed combined-cycle power generating units to continue to use once-through cooling at combined-cycle units until the unit reaches the end of its useful life under certain circumstances. The State Water Board subsequently declined to approve the amendment and instead tabled it for consideration until after the SACCWIS has reviewed facility compliance plans and made recommendations to the Board. While the SACCWIS continues to assess the reliability impacts to the electric grid in connection with implementation of the Policy, its most recent annual report to the Board in March 2013 did not recommend any changes to the final compliance deadline in the Policy for any facility.

In accordance with the Policy, in April 2011, we submitted proposed compliance plans for our Moss Landing facility . For Moss Landing Units 6 and 7, we proposed to continue our ongoing review of potential compliance options taking into account each facility's applicable final compliance deadline. For Moss Landing Units 1 and 2, we proposed to continue current once-through cooling operations through the end of 2032, at which time we would evaluate repowering or installation of feasible control measures. While the Policy is generally at least as stringent as the EPA's proposed rule for cooling water intake structures, compliance with the Policy may not meet all requirements of the forthcoming EPA final rule.

In October 2010, Dynegy Moss Landing, LLC joined with other California power plant owners in filing a lawsuit in the Sacramento County Superior Court challenging the Policy. We cannot predict with confidence the outcome of the litigation at this time. It may not be possible to meet the requirements of the Policy without installing closed cycle cooling systems. Given the numerous variables and factors involved in calculating the potential costs of closed cycle cooling systems, any decision to install such a system at Moss Landing would be made on a case-by-case basis considering all relevant factors at the time. If capital expenditure requirements related to cooling water systems are great enough to render the continued operation of certain of Moss Landing's units uneconomical, we could at our option, and subject to any applicable financing agreements and other obligations, reduce operations at certain of the units or cease to operate such units and forego such capital expenditures.

Effluent Limitation Guidelines. In spring 2013, the EPA proposed revisions to the Effluent Limitation Guidelines ("ELG") for steam electric power generation units. The proposed rule would establish new or additional requirements for wastewater streams associated with steam electric power generation processes and byproducts, including flue gas desulfurization, fly ash, bottom ash and flue gas mercury control. The proposed rule identifies four preferred options for regulation of discharges from existing sources, with the options differing in the number of waste streams covered, the size of the units controlled and the stringency of the controls to be imposed. As proposed, the new ELG requirements would be phased in between 2017 and 2022. The EPA is expected to take final action on the proposal in 2014 and intends to align the ELG rule with its related CCR rule proposed in 2010.

Other CWA Initiatives. The requirements applicable to water quality are expected to increase in the future. A number of efforts are under way within the EPA to evaluate water quality criteria for parameters associated with the by-products of fossil fuel combustion. These parameters relate primarily to arsenic, mercury and selenium. In addition, the EPA has announced it will propose a rule defining the term “waters of the United States,” which is used to determine the jurisdictional reach of the CWA.

Coal Combustion Residuals
The combustion of coal to generate electric power creates large quantities of ash that are managed at power generation facilities in dry form in landfills and in liquid or slurry form in surface impoundments. Each of our coal-fired plants has at least one CCR management unit. At present, CCR is regulated by the states as solid waste. The EPA has considered whether CCR should be regulated as a hazardous waste on two separate occasions, including most recently in 2000, and both times has declined to do so. The December 2008 failure of a CCR surface impoundment dike at the TVA's Kingston Plant in Tennessee accompanied by a very large release of ash slurry has resulted in renewed scrutiny of CCR management.
Dam Safety Assessment Reports. In response to the Kingston ash slurry release, the EPA initiated a nationwide investigation of the structural integrity of CCR surface impoundments. The EPA assessments found all of our surface impoundments to be in satisfactory or fair condition, with the exception of surface impoundments at our Coal segment's Baldwin and Hennepin facilities.
The EPA's final dam safety assessments at our Baldwin and Hennepin facilities, which were issued in spring 2013, rated 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 certain documentation is lacking or incomplete or if further critical studies are needed to identify any potential dam safety deficiencies. The assessments include recommendations for further studies, repairs and changes in operational and maintenance practices.
In response to the final report concerning Hennepin, we notified the EPA of our intent to close the Hennepin west ash pond system. The preliminary estimated cost for closure of the west ash pond system, including post-closure monitoring, is approximately $5 million. As a result of these changes, we increased our ARO by approximately $2 million during the second quarter 2013.
We are performing additional recommended further studies and actions at Baldwin and Hennepin, some of which are dependent on necessary permits being obtained. The estimated cost of repairing the Hennepin east ash pond berms is approximately $2 million. The nature and scope of repairs, if any which ultimately may be needed at the Baldwin ash pond system is dependent on the results of the ongoing recommended studies. At this time, we are unable to estimate a reasonably possible cost or range of costs of repairs for Baldwin, but the repairs may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows. Please read Note 16—Commitments and Contingencies for further discussion.
EPA CCR Rule. In June 2010, the EPA proposed two alternative rules under RCRA for federal regulation of the management and disposal of CCR from electric utilities and independent power producers. One proposal would regulate CCR as a special waste under RCRA subtitle C rules when those wastes are destined for disposal in a landfill or surface impoundment. The subtitle C proposal would subject persons who generate, transport, treat, store or dispose of such CCR to many of the existing RCRA regulations applicable to hazardous waste. While certain types of beneficial use of CCR would be exempt from regulation under the subtitle C proposal, the impact of subtitle C regulation on the continued viability of beneficial use continues to be debated. Regulation under subtitle C would effectively phase out the use of ash ponds for disposal of CCR.
The alternative proposal would regulate CCR disposed in landfills or surface impoundments as a solid waste under subtitle D of RCRA. The subtitle D proposal would establish national criteria for disposal of CCR in landfills and surface impoundments, requiring new units to install composite liners. The subtitle D proposal might also require existing surface impoundments without liners to close or be retrofitted with composite liners within five years. Certain environmental organizations have advocated designation of CCR as a hazardous waste; however, many state environmental agencies have expressed strong opposition to such designation. In August 2013, the EPA issued a Notice of Data Availability regarding its June 2010 proposed CCR rule, seeking comments on a limited number of issues, including new data relevant to updating the risk assessment for the proposed rule, additional information on surface impoundment structural stability, and time frames for closing surface impoundments.
In April 2012, CCR marketers and environmental groups separately filed lawsuits in the U.S. District Court for the District of Columbia seeking to force the EPA to complete its CCR rulemaking as soon as possible. In September 2013, the court ruled that the EPA had failed to complete its statutory obligation to review at least every three years, and revise if necessary, the RCRA subtitle D regulations pertaining to CCR. In January 2014, the EPA entered a

consent decree under which it agreed to take final action by December 19, 2014 on its proposed subtitle D CCR regulations. The court is expected to accept the consent decree. The consent decree does not require the EPA to adopt its proposed subtitle D CCR rule option instead of the subtitle C option; rather, the EPA is only required to decide by the specified date whether or not to adopt the subtitle D option.

Federal legislation to address CCR as a non-hazardous waste also has been introduced in Congress. In July 2013, the U.S. House of Representatives passed H.R. 2218, the Coal Residuals Reuse and Management Act of 2013, which would establish a non-hazardous regulatory framework to govern the disposal of CCR. Similar legislation is expected to be introduced in the U.S. Senate.

Illinois. In October 2013, the Illinois EPA filed a proposed rulemaking with the IPCB that would establish processes governing monitoring, preventative response, corrective action and closure of CCR surface impoundments at power generating facilities. We are reviewing the proposed rule for potential impacts on our operations and expect to participate in the rulemaking process.

Coal Segment. In response to requests by the Illinois EPA, we have implemented hydrogeologic investigations for the CCR surface impoundment at our Coal segment Baldwin facility and for two CCR surface impoundments at our Vermilion facility. Groundwater monitoring results indicate that the CCR surface impoundments at each of these sites impact onsite groundwater.

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 in April 2012, indicate two localized areas where Class I groundwater standards were exceeded; however, the Illinois EPA has not required further investigation. Please read Note 16—Commitments and Contingencies for further discussion.

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

In July 2012, the Illinois EPA issued violation notices alleging violations of groundwater standards onsite at the Baldwin and Vermilion facilities. In December 2012, the Illinois EPA provided written notice that it may pursue legal action with respect to each matter through referral to the Illinois Office of the Attorney General. In accordance with work plans approved by the Illinois EPA, in 2013 we performed a geotechnical study at Vermilion and began a 12-month geotechnical/hydraulic/hydrogeologic study needed to analyze corrective action alternatives at Baldwin. The geotechnical study at Vermilion confirmed that the cap closure option proposed in our corrective action plans for the north and old east ash ponds is technically feasible. Please read Note 16—Commitments and Contingencies for further discussion.

IPH Segment. Hydrogeologic investigations of the CCR surface impoundments have been performed at the IPH segment facilities. Groundwater monitoring results indicate that the CCR surface impoundments at each of the IPH segment facilities potentially impact onsite groundwater.

In 2012, the Illinois EPA issued violation notices with respect to groundwater conditions at the Newton and Coffeen facilities ash pond systems. In February 2013, the Illinois EPA provided written notice that it may pursue legal action with respect to each of these matters through referral to the Illinois Office of the Attorney General. In response, in April 2013, AER filed a proposed site-specific rulemaking with the IPCB which, if approved, would provide for the systematic and eventual closure of all of AER's ash ponds that impact groundwater in exceedance of applicable groundwater standards. AER's proposed rulemaking has been stayed to allow the Illinois EPA proposed rulemaking on power generating facility CCR surface impoundments to proceed. Please read Note 16—Commitments and Contingencies for further discussion.

Climate Change

For the last several years, there has been a robust public debate about climate change and the potential for regulations requiring lower emissions of GHG, primarily CO_2 and methane. We believe that the focus of any federal program attempting to address climate change should include three critical, interrelated elements: (i) the environment, (ii) the economy and (iii) energy security.

We cannot confidently predict the final outcome of the current debate on climate change nor can we predict with confidence the ultimate requirements of proposed or anticipated federal and state legislation and regulations intended to address climate change. These activities, and the highly politicized nature of climate change, suggest a trend toward increased regulation of GHG that could result in a material adverse effect on our financial condition, results of operations and cash flows. Existing and anticipated federal and state regulations intended to address climate change may significantly increase the cost of providing electric power, resulting in far-reaching and significant impacts on us and others in the power generation industry over time. It is possible that federal and state actions intended to address climate change could result in costs assigned to GHG emissions that we would not be able to fully recover through market pricing or otherwise. If capital and/or operating costs related to compliance with regulations intended to address climate change become great enough to render the operations of certain plants uneconomical, we could, at our option and subject to any applicable financing agreements or other obligations, reduce operations or cease to operate such plants and forego such capital and/or operating costs.

Power generating facilities are a major source of GHG emissions. In 2013, our Coal, IPH and Gas segment facilities emitted approximately 22 million, 3 million and 7 million tons of CO_{2e}, respectively. The amounts of CO_{2e} emitted from our facilities during any time period will depend upon their dispatch rates during the period.

Though we consider our largest risk related to climate change to be legislative and regulatory changes, we are subject to physical risks inherent in industrial operations including severe weather events such as hurricanes and tornadoes. To the extent that changes in climate effect changes in weather patterns (such as more severe weather events) or changes in sea level where we have generating facilities, we could be adversely affected. To the extent that climate change results in changes in sea level, we would expect such effects to be gradual and amenable to structural mitigation during the useful life of the facilities. We could experience both risks and opportunities as a result of related physical impacts. For example, more extreme weather patterns such as a warmer summer or a cooler winter could increase demand for our products. However, we also could experience more difficult operating conditions in that type of environment. We maintain various types of insurance in amounts we consider appropriate for risks associated with weather events.

Federal Legislation Regarding Greenhouse Gases. Several bills have been introduced in Congress since 2003 that if passed would compel reductions in CO_2 emissions from power plants. Many of these bills have included cap-and-trade programs. While GHG legislation has been introduced in the 113th Congress (2013-2014), the passage of comprehensive GHG legislation in the next year is considered unlikely.

Federal Regulation of Greenhouse Gases. In April 2007, the U.S. Supreme Court issued its decision in Massachusetts v. EPA, holding that GHGs meet the definition of a pollutant under the CAA and that regulation of GHG emissions is authorized by the CAA.

In response to that decision, the EPA issued a finding in December 2009 that GHG emissions from motor vehicles cause or contribute to air pollution that endangers the public health and welfare. The EPA has since also finalized several rules concerning GHGs as directly relevant to our facilities. In January 2010, the EPA rule on mandatory reporting of GHG emissions from all sectors of the economy went into effect and requires the annual reporting of GHG emissions. We have implemented processes and procedures to report these emissions. In November 2010, the EPA issued PSD and Title V Permitting Guidance for Greenhouse Gases, which focuses on steam turbine and boiler efficiency improvements as a reasonable BACT requirement for coal-fired EGUs. The EPA's Tailoring Rule and Timing Rule phase in GHG emissions annual applicability thresholds for the PSD permit program and for the CAA Title V operating permit program beginning in January 2011. Application of the PSD program to GHG emissions will require implementation of BACT for new and modified major sources of GHG. The EPA intends to complete a subsequent rulemaking in 2016 to determine whether it would be appropriate to lower applicability thresholds identified in the Tailoring Rule.

In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit upheld the EPA's endangerment finding and several EPA GHG-related rules in Coalition For Responsible Regulation, Inc. v. EPA. The court held that the EPA's endangerment finding was not arbitrary and capricious notwithstanding scientific uncertainty and that the Agency had adequate evidence on which to base its finding. The court also held that the Tailpipe Rule was adequately justified and that, upon making the Endangerment Finding, the EPA was required by CAA Section 202 to regulate tailpipe GHG emissions. The court did not address the merits of the arguments challenging the EPA's Tailoring Rule and Timing Rule, instead deciding that the petitioners lacked standing to challenge those rules. In July 2013, the court dismissed challenges by certain states and industry groups to the EPA rules concerning incorporation of GHG requirements into PSD permit programs of SIPs. The court concluded that the petitioners lacked standing, finding that

the CAA's PSD permitting provision is immediately self-executing whenever a pollutant becomes subject to regulation.
In October 2013, the U.S. Supreme Court granted petitions for review in a group of cases involving the EPA's GHG program, including the Tailoring Rule and Timing Rule. The Court will review the limited question of whether the EPA permissibly determined that its regulation of motor vehicle GHG emissions triggered permitting requirements under the CAA for stationary sources that emit GHGs. The Court is expected to issue a decision by mid-2014.
In March 2011, the EPA entered a settlement agreement of a CAA citizen suit under which the Agency would propose NSPS for control of GHG emissions from new and modified EGUs, as well as emission guidelines for control of GHG emissions

from existing EGUs. The lawsuit, New York v. EPA, involves a challenge to the NSPS for EGUs, issued in 2006, because the rule did not establish standards for GHG emissions. The settlement, as amended, required the EPA to issue proposed GHG emissions standards for EGUs by September 2011 and to finalize the standards by May 2012. In March 2012, the EPA proposed GHG NSPS for new EGUs.

In June 2013, President Obama announced his Administration's plan to address climate change. In accordance with the plan, in September 2013, the EPA re-proposed GHG NSPS for new EGUs, with separate emission standards (i.e. pounds of CO_2 per MWh gross output) for natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined cycle ("IGCC") units. The proposed emission standards for fossil fuel-fired utility boilers and IGCC units are based on the performance of a new efficient coal unit implementing partial carbon capture and storage. A final rule is expected in 2014.

The Administration's climate change plan also directs the EPA to propose carbon emission standards for existing EGUs by June 1, 2014, and to finalize such standards by June 1, 2015. SIPs addressing existing EGUs would be due by June 30, 2016. In addition, the EPA has indicated that GHG standards for modified EGUs will be adopted, with a proposed rule to be issued by June 2014 and a final rule by June 2015. The nature and scope of carbon emission requirements, if any, that ultimately may be imposed on existing EGUs cannot be predicted with confidence at this time, but may result in significantly increased compliance costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

State Regulation of Greenhouse Gases. Many states where we operate generation facilities have, are considering, or are in some stage of implementing, state-only regulatory programs intended to reduce emissions of GHGs from stationary sources as a means of addressing climate change.

Illinois. Our assets in Illinois may become subject to a regional GHG cap-and-trade program under the MGGA. The MGGA is an agreement among six states and one Canadian province to create the MGGRP to establish GHG reduction targets and time frames consistent with member states' targets and to develop a market-based and multi-sector cap-and-trade mechanism to achieve the GHG reduction targets. Illinois has set a goal of reducing GHG emissions to 1990 levels by the year 2020, and to 60 percent below 1990 levels by 2050. The MGGA advisory group released a model rule in 2010, but implementation by the MGGA participants has not moved forward.

California. Our assets in California are subject to the California Global Warming Solutions Act ("AB 32"), which requires the CARB to develop a GHG emission control program that will reduce emissions of GHG in the state to their 1990 levels by 2020. CARB's final GHG cap-and-trade regulation took effect on January 1, 2012, but cap-and-trade compliance obligations did not begin until January 1, 2013 due to litigation. The emissions cap set by the CARB for 2013 was about two percent below the emissions level forecast for 2012, declines in 2014 by about two percent, and by about three percent annually from 2015 to 2020. The first compliance period covers 2013-2014.

The CARB's sixth allowance auction was held in February 2014 with 2014 auction allowances selling at a clearing price of $11.48 per ton and 2017 auction allowances selling at a clearing price of $11.38 per ton. The CARB expects allowance prices to be in the $15 to $30 range by 2020.

Our generating facilities in California emitted approximately 2 million tons of GHGs during 2013. As a result of tolling agreements for certain of our California units under which GHG allowance costs are passed through to the tolling counterparty, in 2013 we were required to acquire allowances covering the GHG emissions of only Moss Landing Units 1 and 2 and Morro Bay. We estimate the cost of CARB allowances required to operate our affected facilities during 2013 was approximately $23 million.

We have participated in CARB's quarterly allowance auctions and will procure additional allowances as needed in future auctions and secondary markets. The next quarterly auction is scheduled for May 2014. We estimate the cost of GHG allowances required to operate our units in California during 2014 will be approximately $22 million; however, we expect that the cost of compliance would be reflected in the power market, and the actual impact to gross margin would be largely offset by an increase in revenue. Due to the tolling agreement for Moss Landing Units 6 and 7 under which GHG allowance costs are passed through to the tolling counterparty and the retirement of the Morro Bay facility, we expect to only acquire allowances covering the GHG emissions of Moss Landing Units 1 and 2.

The State of California is also a party to a regional GHG cap-and-trade program being developed under the WCI to reduce GHG emissions in the participating jurisdictions. The WCI started as a collaborative effort among seven states and four Canadian provinces, but California currently is the sole remaining state participant. In October 2013, California announced completion of an agreement that defines the process for working collaboratively and jointly to harmonize and integrate the California and Québec cap-and-trade programs. The linkage of the two programs began January 1, 2014.

In September 2013, CARB released proposed amendments to its GHG cap-and-trade program rule to provide additional clarity in implementation, address cost containment issues, add a new compliance offset protocol and extend transition assistance for covered entities. In November 2013, CARB also adopted amendments to its mandatory GHG reporting rule. In addition, in November 2013, the Sacramento Superior Court rejected lawsuits filed by the California Chamber of Commerce and others challenging the legality of the CARB's cap-and-trade auction. The court decided that the auctions do not constitute a tax but are more akin to a regulatory fee. The California Chamber of Commerce has appealed the court's decision. We continue to monitor developments regarding the California cap-and-trade program and evaluate any potential impacts on our operations.

RGGI. On January 1, 2009, our assets in New York and Maine became subject to a state-driven GHG emission control program known as RGGI. RGGI was developed and initially implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states implemented rules regulating GHG emissions using a cap-and-trade program to reduce CO_2 emissions by at least 10 percent of 2009 emission levels by the year 2018. Compliance with the allowance requirement under the RGGI cap-and-trade program can be achieved by reducing emissions, purchasing or trading allowances, or securing offset allowances from an approved offset project. While allowances are sold by year, actual compliance is measured across a three-year control period. The current control period covers 2012-2014.

In December 2013, RGGI held its twenty-second auction, in which approximately 38 million allowances for the second control period were sold at a clearing price of $3.00 per allowance. RGGI's next quarterly auction is scheduled for March 2014. We have participated in each of the quarterly RGGI auctions (or in secondary markets, as appropriate) to secure allowances for our affected assets.

In February 2013, RGGI released an updated model rule that would reduce the program's 2014 CO_2 emissions cap from 165 million tons to 91 million tons. The cap would decline further by 2.5 percent each year from 2015 to 2020 and be adjusted to account for allowances held by market participants before the new cap is implemented. RGGI also intends to review the program by 2016 to consider potential additional reductions to the cap after 2020. Under the new cap, RGGI expects allowances to be priced at approximately $4.00 per ton in 2014 and to rise to approximately $10.00 per ton in 2020. RGGI will set the allowance auction minimum reserve price at $2.00 per ton and increase it by 2.5 percent per year. The updated model rule would also require covered sources to hold allowances equal to at least 50 percent of their emissions in each of the first two years of the three-year control period. New York and Maine have adopted regulations to implement the requirements of the updated model rule.

Our generating facilities in New York and Maine emitted approximately 2 million tons of CO_2 during 2013. We estimate the cost of allowances required to operate these facilities during 2013 was approximately $7 million. We estimate the cost of RGGI allowances required to operate our affected facilities during 2014 will be approximately $11 million. While adoption of the updated RGGI rules is expected to increase the cost of allowances required to operate our New York and Maine facilities in future years, we expect that the cost of compliance would be reflected in the power market, and the actual impact to gross margin would be largely offset by an increase in revenue.

Climate Change Litigation. There is a risk of litigation from those seeking injunctive relief from power generators or to impose liability on sources of GHG emissions, including power generators, for claims of adverse effects due to climate change.

In June 2011, the U.S. Supreme Court issued its decision in AEP v. Connecticut, which reviewed the U.S. Court of Appeals for the Second Circuit's decision that the U.S. District Court was an appropriate forum for resolving claims by eight states and New York City against six electric power generators related to climate change. The Supreme Court was equally divided by a vote of 4-4 on the question of whether the plaintiffs had standing to bring the suit and, therefore, affirmed the court's exercise of jurisdiction. On the merits the Court ruled by a vote of 8-0 that the CAA and EPA action authorized by the CAA displace any federal common law right to seek abatement of CO_2 emissions from fossil fuel-fired power plants. The Court did not reach the issue of whether the CAA preempts similar claims under state nuisance law.

The U.S. Court of Appeals for the Ninth Circuit has addressed climate change issues in two recent cases. In September 2012, in Native Village of Kivalina v. ExxonMobil Corp. (following the filing of the DH Chapter 11 Cases, the Kivalina plaintiffs voluntarily dismissed DH with prejudice), the Ninth Circuit ruled that the CAA and EPA actions authorized by the Act have displaced federal common law public nuisance claims concerning domestic GHGs. The court, relying heavily on the Supreme Court's 2011 ruling in AEP v. Connecticut, decided that the displacement of federal common law public nuisance claims regarding GHGs applies equally to actions seeking damages or injunctive relief. The Ninth Circuit declined to address whether the plaintiffs had standing or whether plaintiffs' claims were political questions not subject to judicial review. The court subsequently denied the Kivalina plaintiffs' petition for rehearing. In May 2013, the Supreme Court denied the plaintiffs' petition for review.

In October 2013, the Ninth Circuit addressed standing in the GHG context, ruling that it did not have jurisdiction to hear a challenge to the State of Washington's failure to regulate GHGs. In Washington Environmental Council v. Bellon, plaintiffs challenged the state's failure to set RACT limits for GHG emissions from the state's five oil refineries. The Ninth Circuit vacated the district court's decision in favor of the plaintiffs, holding that the plaintiffs lacked standing. The court found that the causal link between the plaintiffs' alleged climate change injuries and the refineries' emissions was too attenuated and that the plaintiffs did not show that their injuries would be redressed by an order requiring the state to impose GHG limits on the refineries. The

Ninth Circuit distinguished the Supreme Court's decision in Massachusetts v. EPA because the private organization plaintiffs, unlike the state plaintiffs in Massachusetts v. EPA, were not entitled to relaxed standing requirements and because the GHG emissions levels at issue, unlike in Massachusetts v. EPA, did not meaningfully contribute to global GHG emissions. In February 2014, the Ninth Circuit declined to rehear the case en banc.

Carbon Initiatives. We participate in several programs that partially offset or mitigate our GHG emissions. In the lower Mississippi River Valley, we have partnered with the U.S. Fish & Wildlife Service to restore more than 45,000 acres of hardwood forests by planting more than 8 million bottomland hardwood seedlings. In 2012, a portion of the Lower Mississippi River Valley reforestation project was registered under the Verified Carbon Standard, the first U.S. forest carbon offset project to receive this certification. In Illinois, we are funding prairie, bottomland hardwood and savannah restoration projects in partnership with the Illinois Conservation Foundation. We also have programs to reuse CCR produced at our coal-fired generation units through agreements with cement manufacturers that incorporate the material into cement products, helping to reduce CO_2 emissions from the cement manufacturing process.

Remedial Laws

We are subject to environmental requirements relating to handling and disposal of toxic and hazardous materials, including provisions of CERCLA and RCRA and similar state laws. CERCLA imposes strict liability for contributions to contaminated sites resulting from the release of "hazardous substances" into the environment. Those with potential liabilities include the current or previous owner and operator of a facility and companies that disposed, or arranged for disposal, of hazardous substances found at a contaminated facility. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to public health or the environment and to seek recovery for costs of cleaning up hazardous substances that have been released and for damages to natural resources from responsible parties. Further, it is not uncommon for neighboring landowners and other affected parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. CERCLA or RCRA could impose remedial obligations with respect to a variety of our facilities and operations.

As a result of their age, a number of our facilities contain quantities of asbestos-containing materials, lead-based paint and/or other regulated materials. Existing state and federal rules require the proper management and disposal of these materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations and removal and abatement of asbestos-containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself.

COMPETITION

Demand for power may be met by generation capacity based on several competing generation technologies, such as natural gas-fired, coal-fired or nuclear generation, as well as power generating facilities fueled by alternative energy sources, including hydro power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. The power generation business is a regional business that is diverse in terms of industry structure. Our Coal, IPH and Gas power generation businesses compete with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies, including retail power companies, and financial institutions in the regions in which we operate. We believe that our ability to compete effectively in the power generation business will be driven in large part by our ability to achieve and maintain a low cost of production, primarily by managing fuel costs and providing reliable service to our customers. Our ability to compete effectively will also be impacted by various governmental and regulatory activities designed to reduce GHG emissions. For example, regulatory requirements for load-serving entities to acquire a percentage of their energy from renewable-fueled facilities will potentially reduce the demand for energy from coal- and gas-fired facilities such as those we own and operate.

SIGNIFICANT CUSTOMERS

Successor

For the year ended 2013, approximately 36 percent, 19 percent, 16 percent and 15 percent of our consolidated revenues were derived from transactions with MISO, PJM, NYISO and CAISO, respectively. For the 2012 Successor Period (as defined below), approximately 34 percent, 13 percent, 15 percent, 16 percent and 14 percent of our consolidated revenues were derived from transactions with MISO, NYISO, PJM, CAISO and NGX, respectively. No other customer accounted for more than 10 percent of our consolidated revenues during the year ended 2013 or the

2012 Successor Period.
Predecessor
For the 2012 Predecessor Period (as defined below), approximately 30 percent, 16 percent, 15 percent and 10 percent of our consolidated revenues were derived from transactions with MISO, NYISO, PJM and DB, respectively. For the year ended December 31, 2011, approximately 38 percent, 11 percent, 23 percent and 12 percent of our consolidated revenues were derived

from transactions with MISO, NYISO, PJM and NGX, respectively. No other customer accounted for more than 10 percent of our consolidated revenues during the 2012 Predecessor Period or the year ended 2011.

EMPLOYEES

At December 31, 2013, we had approximately 260 employees at our corporate headquarters and approximately 1,450 employees at our facilities, including field-based administrative employees. The field-based employees are divided across our three reportable segments, Coal, IPH and Gas, employing approximately 470, 590, and 240 employees, respectively. Approximately 900 employees at our operating facilities are subject to collective bargaining agreements with various unions. We are currently a party to ten different collective bargaining agreements, one of which was renegotiated in 2013. Our collective bargaining agreement with IBEW Local 1245, which represents approximately 70 employees at our Moss Landing and Morro Bay facilities, expires on March 31, 2014. We anticipate that we will successfully reach a new agreement with IBEW Local 1245 in the coming months.

Item 1A. Risk Factors

Please note that any risk, uncertainty or other factor that has a material adverse effect on the financial position, results of operations or cash flows of the businesses in our new segment IPH may not result in a material adverse effect on the financial position, results of operations or cash flows of Dynegy on a consolidated basis due to the size of Dynegy on a consolidated basis relative to the size of the IPH segment or due to the ring-fenced structuring of IPH and its subsidiaries. However, you should review the risk factor regarding the IPH ring-fenced structure and the risk that a creditor of IPH, or a bankruptcy trustee if any entity of the IPH segment were to become a debtor in bankruptcy, may nevertheless be successful in subjecting Dynegy to the claims of IPH and its subsidiaries.

FORWARD-LOOKING STATEMENTS

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

- anticipated benefits and expected synergies resulting from the AER Acquisition and beliefs associated with the integration of operations;
- lack of comparable financial data due to the application of fresh-start accounting;
- expectations regarding our compliance with the Credit Agreement, including collateral demands, interest expense, any applicable financial ratios and other payments;
- efforts to secure retail sales and the timing of such sales;
- 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 and retail 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 regarding successful renegotiation of the IBEW Local 1245 collective bargaining agreement;
- beliefs regarding redevelopment efforts for the Morro Bay facility;
- beliefs and assumptions regarding approval by the CPUC of the SCE 2016 transaction for Moss Landing Units 6 & 7;
- ability to mitigate impacts associated with expiring RMR and/or capacity contracts;
- beliefs about the outcome of legal, administrative, legislative and regulatory matters; and
- expectations regarding performance standards and 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 below.

FACTORS THAT MAY AFFECT FUTURE RESULTS

Risks Related to the Operation of Our Business

Because wholesale and retail power prices are subject to significant volatility and because many of our power generation facilities operate without long-term power sales agreements, our revenues and profitability are subject to wide fluctuations.

Because we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other wholesale and retail power markets on a term basis, we are not guaranteed any rate of return on our capital investments. Rather, our financial condition, results of operations and cash flows will depend, in large part, upon prevailing market prices for power and the fuel to generate such power. Wholesale and retail power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable. Such factors that may materially impact the power markets and our financial results include:

- the existence and effectiveness of demand-side management;
- conservation efforts and the extent to which they impact electricity demand;
- addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation plants, expansion of existing plants or additional transmission capacity;
- regulatory constraints on pricing (current or future) or the functioning of the energy trading markets and energy trading generally;
- environmental regulations and legislation;
- weather conditions, including extreme weather conditions, and seasonal fluctuations;
- electric supply disruptions including plant outages;
- basis risk from transmission losses and congestion and changes in power transmission infrastructure;
- development of new technologies for the production of natural gas;
- fuel price volatility;
- economic conditions; and
- increased competition or price pressure driven by generation from renewable sources.

Many of our facilities operate as “merchant” facilities without long-term power sales agreements. Consequently, there can be no assurance that we will be able to sell any or all of the electric energy, capacity or ancillary services from those facilities at commercially attractive rates or that our facilities will be able to operate profitably. This could lead to less favorable financial results as well as future impairments of our property, plant and equipment or to the retirement of certain of our facilities resulting in economic losses and liabilities.

Given the volatility of commodity power prices, to the extent we do not secure long-term power sales agreements for the output of our power generation facilities, our revenues and profitability will be subject to increased volatility, and our financial condition, results of operations and cash flows could be materially adversely affected.

Our commercial strategies for our wholesale and retail businesses may not be executed as planned, may result in lost opportunities or adversely affect financial performance.

We seek to commercialize our assets through sales arrangements of various types. In doing so, we attempt to balance a desire for greater predictability of earnings and cash flows in the short- and medium-terms with our expectation that commodity prices will rise over the longer term, creating upside opportunities for those with unhedged generation volumes. Our ability to successfully execute this strategy is dependent on a number of factors, many of which are outside our control, including market liquidity and design, correlation risk, commodity cycles, the availability of counterparties willing to transact with us or to transact with us at prices we think are commercially acceptable, the availability of liquidity to post collateral in support of our derivative instruments and the reliability of the systems and models comprising our commercial operations function. The availability of market liquidity and willing counterparties could be negatively impacted by poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties as well as counterparties' views of our creditworthiness. If we are unable to transact in the short- and medium-terms, our financial condition, results of operations and cash flows will be subject to significant uncertainty and volatility. Alternatively, significant contract execution for any such period may precede a run-up in commodity prices, resulting in lost up-side opportunities.

Further, financial performance may be adversely affected if we are unable to effectively manage our power portfolio. A portion of the generation power portfolio is used to provide power under contracts with wholesale and retail customers. To the extent portions of the power portfolio are not needed for that purpose, generation output is sold in the wholesale market. To the extent our power portfolio is not sufficient to meet the requirements of our customers; we must purchase power in the wholesale power markets. Our financial results may be negatively affected if we are unable to manage the power portfolio and cost-effectively meet the requirements of our customers.

A decline in market liquidity and our ability to manage our counterparty credit risk could adversely affect us.

Our supplier counterparties may experience deteriorating credit. These conditions could cause counterparties in the natural gas and power markets, particularly in the energy commodity derivative markets that we rely on for our hedging activities, to withdraw from participation in those markets. If multiple parties withdraw from those markets, market liquidity may be threatened, which in turn could adversely impact our business. Additionally, these conditions may cause our counterparties to seek bankruptcy protection under Chapter 11 or liquidation under Chapter 7 of the Bankruptcy Code. Our credit risk may be exacerbated to the extent collateral held by us cannot be realized or is liquidated at prices not sufficient to recover the full amount of the exposure due to us. There can be no assurance that any such losses or impairments to the carrying value of our financial assets would not materially and adversely affect our financial condition, results of operations and cash flows. In addition, retail sales subject us to credit risk through competitive electricity supply activities to serve commercial and industrial companies and governmental entities. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve that customer, which could have a material adverse affect on our financial condition, results of operations and cash flows.

We are exposed to the risk of fuel and fuel transportation cost increases and interruptions in fuel supplies.

We purchase the fuel requirements for many of our power generation facilities, primarily those that are natural gas-fired, under short-term contracts or on the spot market. As a result, we face the risks of supply interruptions and fuel price volatility, as fuel deliveries may not exactly match those required for energy sales.

Moreover, profitable operation of many of our coal-fired generation facilities is highly dependent on coal prices and coal transportation rates. We monitor our price exposure by entering into term contracts for PRB coal, which we use for our Coal and IPH facilities in the Midwest. Our coal transportation requirements for the Coal and IPH facilities are fully contracted and priced for the next several years. Transportation of PRB coal can also be affected by extreme weather, slowing or stopping the delivery from the mine to the facility.

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.

Further, any changes in the costs of coal, fuel oil, natural gas or transportation rates and changes in the relationship between such costs and the market prices of power will affect our financial results. If we are unable to procure fuel for physical delivery at prices we consider favorable, our financial condition, results of operations and cash flows could be materially adversely affected.

The concentration of our business in Illinois and the MISO may increase the effects of adverse trends in that market and any disruption of production at Kendall, Ontelaunee, Independence or Moss Landing facilities could have a material adverse effect on our financial condition, results of operations and cash flows.

A substantial portion of our business is located in Illinois and the MISO where more than 50 percent of our plant capacity is located. Further, natural disasters in Illinois, including earthquakes along the New Madrid fault line, and changes in economic conditions in MISO, including changing demographics, congestion, or oversupply of or reduced demand for power, could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, a substantial portion of our gross margin is derived from four of our Gas facilities, Kendall, Ontelaunee, Independence and Moss Landing. Any disruption of production at these facilities could have a material adverse effect on our financial condition, results of operations and cash flows.

Operation of power generation facilities involves significant risks customary to the power industry that could have a material adverse effect on our financial condition, results of operations and cash flows.

The ongoing operation of our facilities involves risks customary to the power industry that include the breakdown or failure of equipment or processes, performance below expected levels of output or efficiency and the inability to transport our product to customers in an efficient manner due to a lack of transmission capacity. Unplanned outages of generating units, including extensions of scheduled outages due to mechanical failures or other problems, occur from time to time and are an inherent risk of our business. Further, several of our facilities are old and require periodic upgrading and improvement. Any unexpected failure, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures, could result in reduced profitability. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MW or require us to incur significant costs as a result of running one of our higher cost units or obtaining replacement power from third parties in the open market to satisfy our forward power sales obligations. If we are unsuccessful in operating our facilities efficiently, such inefficiency could have a material adverse effect on our results of operations, financial condition and cash flows.

Our costs of compliance with existing environmental requirements are significant, and costs of compliance with new environmental requirements or factors could materially adversely affect our financial condition, results of operations and cash flows.

Our business is subject to extensive and frequently changing environmental regulation by federal, state and local authorities. Such environmental regulation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, transportation, treatment, storage and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances (including GHG) into the environment, and in connection with environmental impacts associated with cooling water intake structures. Existing environmental laws and regulations may be revised or reinterpreted, new laws and regulations may be adopted or may become applicable to us or our facilities, and litigation or enforcement proceedings could be commenced against us. Proposals being considered by federal and state authorities (including proposals regarding regulation of coal combustion byproducts, ash ponds, cooling water intake structures and GHGs) could, if and when adopted or enacted, require us to make substantial capital and operating expenditures or consider retiring certain of our facilities. If any of these events occur, our financial condition, results of operations and cash flows could be materially adversely affected. Many environmental laws require approvals or permits from governmental authorities before construction, modification or operation of a power generation facility may commence. Certain environmental permits must be renewed periodically in order for us to continue operating our facilities. The process of obtaining and renewing necessary permits can be lengthy and complex and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures. We are required to comply with numerous environmental laws and regulations, and to obtain numerous governmental permits when we modify and operate our facilities. If there is a delay in obtaining any required environmental regulatory approvals or permits, if we fail to obtain any required approval or permit, or if we are unable to comply with the terms of such approvals or permits, the operation of our facilities may be interrupted or become subject to additional costs and/or legal challenges. Further, changed interpretations of existing regulations may subject historical maintenance, repair and replacement activities at our facilities to claims of noncompliance. As a result, our financial condition, results of operations and cash flows could be materially adversely affected. With the continuing trend toward stricter environmental standards and more extensive regulatory and permitting requirements, our capital and operating environmental expenditures are likely to be substantial and may significantly increase in the future.

Our business is subject to complex government regulation. Changes in these regulations or in their implementation may affect costs of operating our facilities or our ability to operate our facilities, or increase competition, any of which would negatively impact our results of operations.

We are subject to extensive federal, state and local laws and regulations governing the generation and sale of energy commodities in each of the jurisdictions in which we have operations. Compliance with these ever-changing laws and regulations requires expenses (including legal representation) and monitoring, capital and operating expenditures. Potential changes in laws and regulations that could have a material impact on our business include: the introduction, or reintroduction, of rate caps or pricing constraints; increased credit standards, collateral costs or margin requirements, as well as reduced market liquidity, as a result of potential OTC market regulation; or a variation of these. Furthermore, these and other market-based rules and regulations are subject to change at any time, and we cannot predict what changes may occur in the future or how such changes might affect any facet of our business.

The costs and burdens associated with complying with the increased number of regulations may have a material adverse effect on us if we fail to comply with the laws and regulations governing our business or if we fail to maintain or obtain advantageous regulatory authorizations and exemptions. Moreover, increased competition within the sector resulting from potential legislative changes, regulatory changes or other factors may create greater risks to the stability of our power generation earnings and cash flows generally.

Availability and cost of emission allowances could materially impact our costs of operations.

We are required to maintain, either through allocation or purchase, sufficient emission allowances to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet our obligations imposed by various applicable environmental laws, and the trend toward more stringent regulations (including regulations regarding GHG emissions) will likely require us to obtain new or additional emission allowances. If our operational needs require more than our allocated quantity of emission allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances, or install costly new emissions controls. As we use the emissions allowances that we have purchased on the open market, costs associated with such purchases will be recognized as an operating expense. If such allowances are available for purchase, but only at significantly higher prices, their purchase could materially increase our costs of operations in the affected markets and materially adversely affect our financial condition, results of operations and cash flows.

Competition in wholesale and retail power markets, together with the age of certain of our generation facilities and an oversupply of power generation capacity in certain regional markets, may have a material adverse effect on our financial condition, results of operations and cash flows.

Our power generation business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies and financial institutions in the sale of electric energy, capacity and ancillary services, as well as in the procurement of fuel, transmission and transportation services. Moreover, aggregate demand for power may be met by generation capacity based on several competing technologies, as well as power generating facilities fueled by alternative or renewable energy sources, including hydroelectric power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Regulatory initiatives designed to enhance and/or subsidize renewable generation could increase competition from these types of facilities. In addition, a buildup of new electric generation facilities in recent years has resulted in an oversupply of power generation capacity in certain regional markets we serve.

We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Electric energy customers, wholesale energy suppliers and transporters often seek financial guarantees, credit support such as letters of credit, and other assurances that their energy contracts will be satisfied. Companies with which we compete may have greater resources in these areas. In addition, certain of our current facilities are relatively old. Newer plants owned by competitors will often be more efficient than some of our plants, which may put these plants at a competitive disadvantage. Over time, some of our plants may become unable to compete because of the construction of new plants, and such new plants could have a number of advantages including: more efficient equipment, newer technology that could result in fewer emissions, or more advantageous locations on the electric transmission system. Additionally, these competitors may be able to respond more quickly to new laws and regulations because of the newer technology utilized in their facilities or the additional resources derived from owning more efficient facilities. Taken as a whole, the potential disadvantages of our aging fleet could result in lower run-times or even early asset retirement.

Other factors may contribute to increased competition in wholesale power markets. New forms of capital and competitors have entered the industry, including financial investors who perceive that asset values are at levels below their true replacement value. As a result, a number of generation facilities in the U.S. are now owned by lenders and investment companies. Furthermore, mergers and asset reallocations in the industry could create powerful new competitors. Under any scenario, we anticipate that we will face competition from numerous companies in the industry.

In addition, the retail marketing activities compete for customers in a competitive environment, which impacts the margins that we can earn on the volumes we are able to serve. Further, with retail competition, residential customers where we serve load can switch to and from competitive electric generation suppliers for their energy needs. If fewer customers switch to another supplier than anticipated, the load we must serve will be greater and, if market prices have increased, our costs will increase due to the need to go to the market to cover the incremental supply obligation. If more customers switch to another supplier than anticipated, the load we must serve will be lower and, if market prices have decreased, we could lose opportunities in the market.

Moreover, many companies in the regulated utility industry, with which the wholesale power industry is closely linked, are also restructuring or reviewing their strategies. Several of those companies have discontinued or are discontinuing their unregulated activities and seeking to divest or spin-off their unregulated subsidiaries. Some of those companies have had, or are attempting to have, their regulated subsidiaries acquire assets out of their or other companies' unregulated subsidiaries. This may lead to increased competition between the regulated utilities and the unregulated power producers within certain markets. To the extent that competition increases, our financial condition, results of operations and cash flows may be materially adversely affected.

With the exception of Joppa, we do not own or control transmission facilities required to sell the wholesale power from our generation facilities. If the transmission service is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. Furthermore, these transmission facilities are operated by RTOs and ISOs, which are subject to changes in structure and operation and impose various pricing limitations. These changes and pricing limitations may affect our ability to deliver power to the market that would, in turn, adversely affect the profitability of our generation facilities.

Other than for Joppa, which owns and controls transmission lines interconnecting the EEI control area to MISO, TVA and LGE, we do not own or control the transmission facilities required to sell the wholesale power from most of our generation facilities. If the transmission service from these facilities is unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. RTOs and ISOs provide transmission services, administer transparent and competitive power markets and maintain system reliability. Many of these RTOs and ISOs operate in the real-time and day-ahead markets in which we sell energy. The RTOs and ISOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, offer caps and other mechanisms to guard against the potential exercise of market power in these markets as well as price limitations. These types of price limitations and other regulatory mechanisms may adversely affect the profitability of our generation facilities that sell energy and capacity into the wholesale power markets. Problems or delays that may arise in the formation and operation of maturing RTOs and similar market structures, or changes in geographic scope, rules or market operations of existing RTOs, may also affect our ability to sell, the prices we receive or the cost to transmit power produced by our generating facilities. Rules governing the various regional power markets may also change from time to time, which could affect our costs or revenues. Additionally, if the transmission service from these facilities is unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be materially adversely affected. Furthermore, the rates for transmission capacity from these facilities are set by others and thus are subject to changes, some of which could be significant. As a result, our financial condition, results of operations and cash flows may be materially adversely affected.

Our Retail business is subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to its reputation and/or the results of operations of the Retail business.

The Retail business requires access to sensitive customer data in the ordinary course of business. Examples of sensitive customer data are names, addresses, account information, historical electricity usage, expected patterns of use, payment history, credit bureau data and bank account information. The Retail business may need to provide sensitive customer data to vendors and service providers who require access to this information in order to provide services, such as call center operations, to the Retail business. If a significant breach occurred, our reputation and that of Homefield Energy's may be adversely affected, customer confidence may be diminished, or we may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or financial condition, results of operations and cash flows.

Unauthorized hedging and related activities by our employees could result in significant losses.

We intend to continue our commercial strategy, which emphasizes forward power sales opportunities intended to reduce the market price exposure of the Company to power price declines. We have various internal policies and procedures designed to monitor hedging activities and positions. These policies and procedures are designed, in part, to prevent unauthorized purchases or sales of products by our employees. We cannot assure, however, that these steps will detect and prevent all violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. A significant policy violation that is not detected could result in a substantial financial loss for us.

Our risk management policies cannot fully eliminate the risk associated with our commodity trading activities.
Our asset-based power position as well as our power marketing, fuel procurement and other commodity trading activities expose us to risks of commodity price movements. We attempt to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, we cannot predict the impact that our commodity trading activities and risk management decisions may have on our business and/or financial condition, results of operations and cash flows.
Our financial condition, results of operations and cash flows would be adversely impacted by strikes or work stoppages by our unionized employees.
A majority of the employees at our facilities are subject to collective bargaining agreements with various unions. Additionally, unionization activities, including votes for union certification, could occur at our non-union generating facilities in our fleet. If union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strike or disruption, we could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor is uncertain. Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms could have a material adverse effect on our financial condition, results of operations and cash flows.
Failure to successfully integrate IPH's coal generation and retail marketing business with our existing generation business may materially and adversely affect our financial condition, results of operations and cash flows.
The success of the AER Acquisition will depend, in part, on our ability to realize the anticipated benefits and synergies from adding IPH's coal generation and retail marketing business to our existing generation business. To realize these anticipated benefits, the businesses must complement each other. If the businesses 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, integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the acquisition. These integration difficulties could materially and adversely affect our financial condition, results of operations and cash flows.
The IPH segment’s ring-fencing structure may not work as planned and Dynegy may be subject to the claims of the creditors of IPH and its subsidiaries.
In connection with the AER Acquisition, IPH and its direct and indirect subsidiaries were organized into ring-fenced groups. The entities within the IPH ring-fenced structure maintain corporate separateness from our other current legal entities. This structure was implemented, in part, to minimize the risk that creditors of IPH, or a bankruptcy trustee if any entity of the IPH segment were to become a debtor in a bankruptcy case, would attempt to assert claims against Dynegy for payment of IPH's obligations. We believe the ring-fenced structure should preclude any corporate veil-piercing or other similar claims of IPH’s creditors but, if any such claims were successful, it could have a material adverse effect on our financial position, results of operations and cash flows. We also believe the ring-fenced structure should preclude any bankruptcy court from ordering the substantive consolidation of Dynegy’s assets and liabilities with the assets and liabilities of any IPH debtor in bankruptcy. However, bankruptcy courts have broad equitable powers, and as a result, outcomes in bankruptcy proceedings are inherently difficult to predict. To the extent a bankruptcy court were to determine that substantive consolidation was appropriate under the facts and circumstances, it could have a material adverse effect on our financial position, results of operations and cash flows.
Terrorist attacks and/or cyber-attacks may result in our inability to operate and fulfill our obligations, and could result in material repair costs.
As a power generator, we face heightened risk of terrorism, including cyber terrorism, either by a direct act against one or more of our generating facilities or an act against the transmission and distribution infrastructure that is used to transport our power. We rely on information technology networks and systems to operate our generating facilities, engage in asset management activities, and process, transmit and store electronic information. Security breaches of this information technology infrastructure, including cyber-attacks and cyber terrorism, could lead to system

disruptions, generating facility shutdowns or unauthorized disclosure of confidential information related to our employees, vendors and counterparties.
Systemic damage to one or more of our generating facilities and/or to the transmission and distribution infrastructure could result in our inability to operate in one or all of the markets we serve for an extended period of time. If our generating facilities are shut down, we would be unable to respond to the ISOs and RTOs or fulfill our obligations under various energy and/or capacity arrangements, resulting in lost revenues and potential fines, penalties and other liabilities. Pervasive cyber-

attacks across our industry could affect the ability of ISOs and RTOs to function in some regions. The cost to restore our generating facilities after such an occurrence could be material.

Risks Related to Our Financial Structure, Level of Indebtedness and Access to Capital Markets

Restrictive covenants may adversely affect operations.

The Credit Agreement and Senior Notes contain 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, including restricting our ability to finance future operations and capital needs and limiting our ability to engage in other business activities.

Our non-investment grade status may adversely impact our commercial operations, increase our liquidity requirements and increase the cost of refinancing opportunities. We may not have adequate liquidity to post required amounts of additional collateral.

Our corporate family credit rating is currently below investment grade and we cannot assure you that our credit ratings will improve, or that they will not decline, in the future. Our credit ratings may affect the evaluation of our creditworthiness by trading counterparties and lenders, which could put us at a disadvantage to competitors with higher or investment grade ratings. We use a portion of our capital resources, in the form of cash, short-term investments, lien capacity and letters of credit, to satisfy these counterparty collateral demands. Our commodity agreements are tied to market pricing and may require us to post additional collateral under certain circumstances. If we are unable to reliably forecast or anticipate collateral calls or if market conditions change such that counterparties are entitled to additional collateral, our liquidity could be strained and may have a material adverse effect on our financial condition, results of operations and cash flows. Factors that could trigger increased demands for collateral include changes in our credit rating or liquidity and changes in commodity prices for power and fuel, among others. Should our ratings continue at their current levels, or should our ratings be further downgraded, we would expect these negative effects to continue and, in the case of a downgrade, become more pronounced.

Risks Related to Investing

Information contained in our historical financial statements prior to the Plan Effective Date is not comparable to the information contained in our financial statements following the Plan Effective Date due to the application of fresh-start accounting.

Following the consummation of the Plan, our financial condition and results of operations from and after the Plan Effective Date will not be comparable to the financial condition or results of operations reflected in our historical financial statements due to the application of fresh-start accounting. Fresh-start accounting requires us to adjust our assets and liabilities to their estimated fair values using the acquisition method. Adjustments to the carrying amounts were material and will affect prospective results of operations as balance sheet items are settled, depreciated, amortized or impaired. As a result, this will make it difficult to assess our performance in relation to prior periods.

We may pursue acquisitions or combinations that could be unsuccessful or present unanticipated problems for our business in the future, which would adversely affect our ability to realize the anticipated benefits of those transactions.

We may enter into transactions that include acquiring or combining with other businesses. We may not be able to identify suitable acquisition or combination opportunities or financing to complete any particular acquisition or combination successfully. Furthermore, acquisitions and combinations involve a number of risks and challenges, including:

- the ability to obtain required regulatory and other approvals;
- the need to integrate acquired or combined operations with our operations;
- potential loss of key employees;

- difficulty in evaluating the assets, operating costs, infrastructure requirements, environmental and other liabilities and other factors beyond our control;
- potential lack of operating experience in new geographic/power markets or with different fuel sources;
- an increase in our expenses and working capital requirements;
- management's attention may be temporarily diverted; and
- the possibility that we may be required to issue a substantial amount of additional equity and/or debt securities or assume additional debt in connection with any such transactions.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize synergies or other anticipated benefits from a strategic transaction. Furthermore, the market for transactions is highly competitive, which may adversely affect our ability to find transactions that fit our strategic objectives or increase the price we would be required to pay (which could decrease the benefit of the transaction or hinder our desire or ability to consummate the transaction). Consistent with industry practice, we routinely engage in discussions with industry participants regarding potential transactions, large and small. We intend to continue to engage in strategic discussions and will need to respond to potential opportunities quickly and decisively. As a result, strategic transactions may occur at any time and may be significant in size relative to our assets and operations.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

We have included descriptions of the location and general character of our principal physical operating properties by segment in "Item 1. Business," which is incorporated herein by reference. Substantially all of the assets of the Coal and Gas segments, including the power generation facilities owned by DMG and DPC, respectively, two of our indirect and wholly-owned subsidiaries, are pledged as collateral to secure the repayment of, and our other obligations under, the Credit Agreement. None of the power generation facilities of the IPH segment are pledged as collateral to secure repayment of any of our debt obligations; however, there are certain restrictions on property sales. Please read Note 12—Debt for further discussion.

Our principal executive office located in Houston, Texas, is held under a lease that expires in 2022. We also lease additional offices in Illinois.

Item 3. Legal Proceedings

Please read Note 16—Commitments and Contingencies—Legal Proceedings for a description of our material legal proceedings, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Upon our emergence from bankruptcy on the Plan Effective Date, all shares of our old common stock were canceled and 100 million shares of new common stock of Dynegy were distributed to the holders of certain classes of claims. Our authorized capital stock consists of 420 million shares of common stock and 20 million shares of preferred stock. Further, on the Plan Effective Date, a total of approximately 6.1 million shares of our new common stock was available for issuance under our 2012 Long Term Incentive Plan. The former holders of our old common stock, as the beneficiaries of Legacy Dynegy's administrative claim against DH under the Plan, also received distributions of our new common stock and five-year warrants to purchase shares of our new common stock (the "Warrants"). The Warrants entitle the holders to purchase up to 15.6 million shares of our new common stock. The maximum number of shares of our new common stock issuable pursuant to each Warrant is one. The exercise price of each Warrant to receive one share of our new common stock was set at $40 per share. Please read Note 21—Emergence from Bankruptcy and Fresh-Start Accounting for additional information regarding the bankruptcy.

Our new common stock is listed on the NYSE under the symbol "DYN" and has been trading since October 3, 2012. No established public trading market existed for our new common stock prior to this date. The number of stockholders of record of our common stock as of February 21, 2014, based on information provided by our transfer agent, was 2,725.

The following table sets forth the per share high and low closing prices for our common stock as reported on the

NYSE for the periods presented:

	High	Low
2014:		
First Quarter (through February 21, 2014)	$22.70	$19.57
2013:		
Fourth Quarter	$21.93	$18.50
Third Quarter	$22.79	$19.09
Second Quarter	$24.76	$22.00
First Quarter	$23.99	$19.39
2012:		
Fourth Quarter	$19.35	$17.35

We have paid no cash dividends on our common stock and have no current intention of doing so. Any future determinations to pay cash dividends will be at the discretion of our Board of Directors, subject to applicable limitations under Delaware law, and will be dependent upon our results of operations, financial condition, contractual restrictions and other factors deemed relevant by our Board of Directors.

Registration Rights Agreement. As part of the Plan, we entered into a registration rights agreement (the “Registration Rights Agreement”) with Franklin Advisers, Inc. (“FAV”), which owns approximately 27 percent of our outstanding common stock as of February 21, 2014. Pursuant to the Registration Rights Agreement, among other things, we were required to use reasonable best efforts to file within 90 days after the Plan Effective Date a registration statement on any permitted form that qualifies (the “Shelf”), and is available, for the resale of “Registrable Securities,” as defined below, with the SEC. Such Shelf was filed in December 2012 and was effective in 2013. Upon Dynegy becoming a well-known seasoned issuer, which occurred on October 1, 2013, we were required to promptly register the sale of all of the Registrable Securities under an automatic shelf registration statement, and to cause such registration statement to remain effective thereafter until there are no longer Registrable Securities. We converted our Form S-1 registration statement into the automatic shelf registration statement on October 2, 2013.

Registrable Securities are shares of our common stock, par value $0.01 per share issued or issuable on or after the Plan Effective Date to any of the original parties to the Registration Rights Agreement, including, without limitation, upon the conversion of our outstanding Warrants, and any securities paid, issued or distributed in respect of any such new common stock, but excluding shares of common stock acquired in the open market after the Plan Effective Date. At any time prior to the five-year anniversary of the Plan Effective Date and from time to time after the later of (i) when the Shelf has been declared effective by the SEC and (ii) 210 days after the Plan Effective Date, any one or more holders of Registrable Securities may request to sell all or any portion of their Registrable Securities in an underwritten offering, provided that such holder or holders will be entitled to make such demand only if the total offering price of the Registrable Securities to be sold in such offering is reasonably expected to exceed 5 percent of the market value of our then issued and outstanding common stock or the total offering price is reasonably expected to exceed $250 million. We are not obligated to effect more than two such underwritten offerings during any period of 12 consecutive months after the Plan Effective Date and are not obligated to effect such an underwritten offering within 120 days after the pricing of a previous underwritten offering. In addition, holders of Registrable Securities may request to sell all or any portion of their Registrable Securities in a non-underwritten offering by providing notice to us no later than two business days (or in certain circumstances five business days) prior to the expected date of such an offering, subject to certain exceptions provided for in the Registration Rights Agreement.

When we propose to offer shares in an underwritten offering whether for our own account or the account of others, holders of Registrable Securities will be entitled to request that their Registrable Securities be included in such offering, subject to specific exceptions.

The registration rights granted in the Registration Rights Agreement are subject to customary indemnification and contribution provisions, as well as customary restrictions such as minimums, blackout periods and, if a registration is for an underwritten offering, limitations on the number of shares to be included in the underwritten offering may be imposed by the managing underwriter. Registrable Securities shall cease to constitute Registrable Securities upon the earliest to occur of: (i) the date on which such securities are disposed of pursuant to an effective registration statement under the Securities Act; (ii) the date on which such securities are disposed of pursuant to Rule 144 (or any successor provision) promulgated under the Securities Act; (iii) with respect to the Registrable Securities held by any Holder (as defined in the Registration Rights Agreement), any time that such Holder Beneficially Owns (as defined in Rule 13d-3 under the Exchange Act) Registrable Securities representing less than 1percent of the then outstanding new common stock and is permitted to sell such Registrable Securities under Rule 144(b)(1); and (iv) the date on which such securities cease to be outstanding.

Stockholder Return Performance Presentation. The following graph compares the cumulative total stockholder return from October 3, 2012, the date our common stock began trading following the Plan Effective Date, through December 31, 2013, for our current existing common stock, the S&P Midcap 400 index and a customized peer group. Because the value of Legacy Dynegy's old common stock bears no relation to the value of our existing common stock, the graph below reflects only our current existing common stock. The peer group consists of Calpine Corp. and NRG Energy Inc. The graph tracks the performance of a $100 investment in our current existing common stock, in the peer group, and the index (with the reinvestment of all dividends) from October 3, 2012 through December 31, 2013.

	October 3, 2012	December 31, 2012	December 31, 2013
Dynegy Inc.	$100.00	$99.12	$111.50
S&P Midcap 400	$100.00	$104.44	$139.42
Peer Group	$100.00	$102.88	$118.36

The stock price performance included in this graph is not necessarily indicative of future stock price performance. The above stock price performance comparison and related discussion is not deemed to be incorporated by reference by any general statement incorporating by reference this Form 10-K into any filing under the Securities Act of 1933, as amended (the "Securities Act") or under the Securities Exchange Act of 1934, as amended (the "Exchange Act") or otherwise, except to the extent that we specifically incorporate this stock price performance comparison and related discussion by reference, and is not otherwise deemed "filed" under the Securities Act or Exchange Act.

Unregistered Sales of Equity Securities and Use of Proceeds. We did not have any purchases of equity securities during the quarter ended December 31, 2013. We do not have a stock repurchase program.
Securities Authorized for Issuance Under Equity Compensation Plans. Please read Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for information regarding securities authorized for issuance under our equity compensation plans.

Item 6. Selected Financial Data

The selected financial information presented below for the year ended December 31, 2013, the period from October 2 through December 31, 2012, the period from January 1 through October 1, 2012 and the year ended December 31, 2011 was derived from, and is qualified by, reference to our Consolidated Financial Statements, including the notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial Statements and related notes and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.” As described in Note 3—Merger and Acquisitions, Legacy Dynegy merged with DH on September 30, 2012. The accounting treatment of the Merger is reflected as a “reverse recapitalization,” whereby DH is the surviving accounting entity for financial reporting purposes. Therefore, our historical results for periods prior to the Merger are the same as DH's historical results.

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 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.

	Successor		Predecessor			
(in millions, except per share data)	Year Ended December 31, 2013 (1)	October 2 Through December 31, 2012	January 1 Through October 1, 2012 (2)	Year Ended December 31, 2011(3)	2010	2009
Statement of Operations Data:						
Revenues	$1,466	$312	$981	$1,333	$2,059	$2,195
Depreciation expense	$(216)	$(45)	$(110)	$(295)	$(397)	$(327)
Goodwill impairment	$—	$—	$—	$—	$—	$(433)
Impairment and other charges, exclusive of goodwill impairment shown separately above	$—	$—	$—	$(5)	$(146)	$(326)
General and administrative expense	$(97)	$(22)	$(56)	$(102)	$(158)	$(159)
Operating income (loss)	$(318)	$(104)	$5	$(189)	$(32)	$(632)
Bankruptcy reorganization items, net	$(1)	$(3)	$1,037	$(52)	$—	$—
Interest expense and debt extinguishment costs (4)	$(108)	$(16)	$(120)	$(369)	$(363)	$(461)
Income tax benefit	$58	$—	$9	$144	$194	$235
Income (loss) from continuing operations	$(359)	$(113)	$130	$(431)	$(259)	$(920)
Income (loss) from discontinued operations, net of taxes (5)	$3	$6	$(162)	$(509)	$17	$(348)
Net loss	$(356)	$(107)	$(32)	$(940)	$(242)	$(1,268)
Net loss attributable to Dynegy Inc.	$(356)	$(107)	$(32)	$(940)	$(242)	$(1,253)
Basic loss per share from continuing operations (6)	$(3.59)	$(1.13)	N/A	N/A	N/A	N/A
Basic income per share from discontinued operations (6)	$0.03	$0.06	N/A	N/A	N/A	N/A
Basic loss per share (6)	$(3.56)	$(1.07)	N/A	N/A	N/A	N/A
Cash Flow Data:						
Net cash provided by (used in) operating activities	$175	$(44)	$(37)	$(1)	$423	$152
	$474	$265	$278	$(229)	$(520)	$790

Net cash provided by (used in) investing activities						
Net cash provided by (used in) financing activities	$(154)	$(328)	$(184)	$375	$(69)	$(1,193)
Capital expenditures, acquisitions and investments	$136	$(46)	$193	$(21)	$(517)	$(596)

35

	Successor		Predecessor		
	December 31,		December 31,		
(amounts in millions)	2013	2012	2011 (2)	2010	2009
Balance Sheet Data:					
Current assets	$1,685	$1,043	$3,569	$2,180	$1,988
Current liabilities	$721	$347	$3,051	$1,562	$1,848
Property, plant and equipment, net	$3,315	$3,022	$2,821	$6,273	$7,117
Total assets	$5,291	$4,535	$8,311	$9,949	$10,903
Notes payable and current portion of long-term debt	$13	$29	$7	$148	$807
Long-term debt (excluding current portion) (7)	$1,979	$1,386	$1,069	$4,626	$4,775
Capital leases not already included in long-term debt	$—	$—	$—	$—	$4
Total stockholders'/member's equity	$2,207	$2,503	$32	$2,719	$3,003

(1) We completed the AER Acquisition effective December 2, 2013; therefore, the results of our IPH segment are only included subsequent to December 2, 2013. Please read Note 3—Merger and Acquisitions—AER Transaction Agreement for further discussion.

(2) We completed the DMG Acquisition effective June 5, 2012; therefore, the results of our Coal segment are only included subsequent to June 5, 2012. Please read Note 3—Merger and Acquisitions—DMG Transfer and Acquisition for further discussion.

(3) We completed the DMG Transfer effective September 1, 2011; therefore, the results of our Coal segment are only included prior to September 1, 2011. Please read Note 23—Dispositions and Discontinued Operations for further discussion.

(4) Includes $11 million, $21 million and $46 million of debt extinguishment costs for the years ended December 31, 2013, 2011 and 2009, respectively.

(5) Discontinued operations include the results of operations from the following businesses:

- The DNE Debtor Entities (please read Note 23—Dispositions and Discontinued Operations for further discussion of the sale of the DNE facilities);
- The Arlington Valley and Griffith power generation facilities (collectively, the "Arizona power generation facilities") (sold fourth quarter 2009);
- Bluegrass power generating facility (sold fourth quarter 2009); and
- Heard County power generating facility (sold second quarter 2009).

(6) 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 for the Predecessor.

(7) As a result of the DH Chapter 11 Cases, we reclassified approximately $3.6 billion in long-term debt to LSTC as of December 31, 2011. These liabilities were settled upon our emergence from bankruptcy on the Plan Effective Date. Please read Note 21—Emergence from Bankruptcy and Fresh-Start Accounting for further discussion.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
The following discussion should be read together with the consolidated financial statements and the notes thereto included in this report.

OVERVIEW

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 three separate segments in our consolidated financial statements: (i) Coal, (ii) IPH and (iii) 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 December 2, 2013, pursuant to the AER Transaction Agreement by and between IPH and Ameren, IPH completed the AER Acquisition. Pursuant to the AER Transaction Agreement, IPH indirectly acquired Illinois Power Resources, LLC's, formerly AER, subsidiaries, including (i) Illinois Power Generating Company, formerly AEGC, (ii) Illinois Power Resources Generating, LLC, formerly AERG, (iii) Illinois Power Fuels and Services Company, formerly Ameren Energy Fuels and Services Company, and (iv) Illinois Power Marketing Company, formerly AEM. The acquisition added 4,062 MW of generation in Illinois and also included the Homefield Energy retail business. There was no cash consideration or stock issued as part of the purchase price. In connection with the AER Acquisition, Ameren retained certain historical obligations of IPR and its subsidiaries, including certain historical environment and tax liabilities. Genco's approximately $825 million in aggregate principal amount of notes remain outstanding as an obligation of Genco. Additionally, Ameren is required to maintain its existing credit support, including all of its collateral obligations with respect to IPM, for a period not to exceed two years following closing. As discussed below, IPH and its direct and indirect subsidiaries are organized into ring-fenced groups and maintain corporate separateness from Dynegy and our other legal entities.

Please read Note 3—Merger and Acquisitions—AER Transaction Agreement for further discussion.

Refinancing of Debt Obligations

During the year ended December 31, 2013, we refinanced existing indebtedness and materially reduced our future cash interest payments, providing us greater financial flexibility.

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

Senior Notes. On May 20, 2013, Dynegy and its Subsidiary Guarantors entered into an Indenture pursuant to which Dynegy issued $500 million in aggregate principal amount of Senior Notes. Borrowings under the Senior Notes were used to repay in full and terminate commitments under a portion of the senior, secured term loans. In connection with the issuance and sale of the Senior Notes, Dynegy and the Subsidiary Guarantors entered into a registration rights agreement with Morgan Stanley and Credit Suisse (the "Senior Notes Registration Rights Agreement"). Pursuant to the Senior Notes Registration Rights Agreement, Dynegy and the Subsidiary Guarantors have agreed for the benefit of the holders of the Senior Notes to use commercially reasonable efforts to register with the SEC a new issue of senior notes due 2023 having substantially identical terms as the Senior Notes as part of an offer to exchange freely tradable exchange notes for the Senior Notes. Pursuant to the Senior Notes Registration Rights Agreement, Dynegy and the Subsidiary Guarantors have agreed to use commercially reasonable efforts to (i) cause a registration statement relating to such exchange offer to be declared effective within 360 days after May 20, 2013 and (ii) if required under certain circumstances, file a shelf registration statement with the SEC covering resales of the Senior Notes. On December 9, 2013, Dynegy and the Subsidiary Guarantors filed a Form S-4 registration statement and filed an amendment to such Form S-4 on January 23, 2014.

Please read Note 12—Debt for further discussion.

Table of Contents

Collective Bargaining Agreement - IBEW Local 51

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

Business Discussion

The following is a brief discussion of each of our segments, including a list of key factors that have affected, and are expected to continue to affect, their respective earnings and cash flows. We also present a brief discussion of our corporate-level expenses.

Power Generation Business

We generate earnings and cash flows in the three segments within our power generation business through sales of electric energy, capacity and ancillary services. Primary factors affecting our earnings and cash flows in the power generation business include:

- Prices for power, natural gas, coal and fuel oil, which in turn are largely driven by supply and demand. Demand for power can vary due to weather and general economic conditions, among other things. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation;
- The relationship between electricity prices and prices for natural gas and coal, commonly referred to as the "spark spread" and "dark spread," respectively, which impacts the margin we earn on the electricity we generate; and
- Our ability to enter into commercial transactions to mitigate short- and medium- term earnings volatility and our ability to manage our liquidity requirements resulting from potential changes in collateral requirements as prices move.

Other factors that have affected, and are expected to continue to affect, earnings and cash flows for this business include:

- Transmission constraints, congestion, and other factors that can affect the price differential between the locations where we deliver generated power and the liquid market hub;
- Our ability to control capital expenditures, which primarily include maintenance, safety, environmental and reliability projects, and to control operating expenses through disciplined management;
- Our ability to optimize our assets by maintaining a high in-market availability, reliable run-time and safe, low-cost operations;
- Our ability to operate and market production from our facilities during periods of planned/unplanned electric transmission outages;
- Our ability to post the collateral necessary to execute our commercial strategy;
- The cost of compliance with existing and future environmental requirements that are likely to be more stringent and more comprehensive (please read Item 1. Business—Environmental Matters for further discussion);
- Market supply conditions resulting from federal and regional renewable power mandates and initiatives;
- Our ability to maintain sufficient coal inventories, which is dependent upon the continued performance of the mines, railroads and barges for deliveries of coal in a consistent and timely manner, and its impact on our ability to serve the critical winter and summer on-peak loads;
- Costs of transportation related to coal deliveries;
- Regional renewable energy mandates and initiatives that may alter supply conditions within the ISO and our generating units' positions in the aggregate supply stack;
- Changes in MISO market design or associated rules;

- Changes in the existing bilateral MISO capacity markets and any resulting effect on future capacity revenues;
- Our ability to maintain and operate our plants in a manner that ensures we receive full capacity payments under our various tolling agreements;
- Our ability to mitigate impacts associated with expiring RMR and/or capacity contracts;

Table of Contents

- Our ability to maintain the necessary permits to continue to operate our Moss Landing facility with once-through, seawater cooling systems;
- The costs incurred to demolish and/or remediate the South Bay and Vermilion facilities;
- Changes in the existing bilateral CAISO resource adequacy markets and any resulting effect on future capacity revenues;
- Access to capital markets on reasonable terms, interest rates and other costs of liquidity;
- Interest expense; and
- Income taxes, which will be impacted by our ability to realize value from our NOLs and AMT credits.

Please read "Item 1A. Risk Factors" for additional factors that could affect our future operating results, financial condition and cash flows.

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.

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

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

On May 20, 2013, Dynegy and its Subsidiary Guarantors entered into an Indenture pursuant to which Dynegy issued $500 million in aggregate principal amount of Senior Notes. Borrowings under the Senior Notes were used to repay in full and terminate commitments under a portion of the senior, secured term loans (as discussed above).

On December 2, 2013, in connection with the AER Acquisition, Genco's approximately $825 million in aggregate principal amount of unsecured senior notes (the "Genco Senior Notes") remained outstanding as an obligation of Genco. The Genco Senior Notes bear interest at rates from 6.30 percent per annum to 7.95 percent per annum and mature between 2018 and 2032. Additionally, Ameren is required to maintain its existing credit support, including all of its collateral obligations with respect to IPM, for a period not to exceed two years.

Please read Note 12—Debt for further discussion.

Current Liquidity. The following table summarizes our liquidity position at December 31, 2013.

	December 31, 2013		
(amounts in millions)	Dynegy Inc.	IPH (1) (2)	Total
Revolver capacity	$475	$—	$475
Less: Outstanding letters of credit	(157)	—	(157)
Revolver availability	318	—	318
Cash and cash equivalents	628	215	843
Total available liquidity	$946	$215	$1,161

(1) Includes Cash and cash equivalents of $190 million related to Genco.

(2) As previously discussed, due to the ring-fenced nature of IPH, cash at the IPH and Genco entities may not be moved out of these entities without meeting certain criteria. However, cash at these entities is available to support current operations of these entities.

Operating Activities

Historical Operating Cash Flows. Our cash flow provided by operations totaled $175 million for the year ended December 31, 2013. During the period, our power generation business provided cash of $199 million primarily due to the operation of our power generation facilities, partially offset by interest payments to service debt related to the DPC and DMG credit agreements. Corporate and other operations used cash of approximately $80 million primarily due to interest payments to service debt related to our Credit Agreement and Senior Notes, payments to advisors, employee-related payments and other general and administrative expense. This use of cash was partially offset by $56 million in positive changes in working capital, which includes $34 million for the return of collateral.

Our cash flow used in operations totaled $44 million for the 2012 Successor Period. During the period, our power generation business used cash of $55 million primarily due to losses incurred during the period. Corporate and other operations used cash of approximately $23 million primarily due to payments to advisors, employee-related payments and other general and administrative expense. These uses of cash were partially offset by $34 million in positive changes in working capital, which includes $30 million for the return of collateral.

Our cash flow used in operations totaled $37 million for the 2012 Predecessor Period. During the period, our power generation business used cash of $56 million primarily due to increased collateral postings to satisfy our counterparty collateral demands and other negative working capital. Corporate and other operations provided cash of approximately $19 million primarily due to interest payments received from Legacy Dynegy on the Undertaking, partially offset by payments to advisors and other general and administrative expense.

Our cash flow used in operations totaled $1 million for the year ended December 31, 2011. During the period, our power generation business provided positive cash flow from operations of $348 million primarily due to the operation of our power generation facilities and positive changes in working capital, which includes decreased collateral postings for the return of collateral, partially offset by interest payments to service debt. Corporate and other operations used cash of $349 million primarily due to interest payments to service debt, employee-related payments and restructuring costs.

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

Table of Contents

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

(amounts in millions)	December 31, 2013	December 31, 2012
Dynegy Inc.:		
Cash (1)	$22	$64
Letters of credit	157	252
Total Dynegy Inc.	179	316
IPH:		
Cash (1) (2)	7	—
Total IPH	7	—
Total	$186	$316

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(1) Includes broker margin as well as other collateral postings included in Prepayments and other current assets on our consolidated balance sheets. As of December 31, 2013 and December 31, 2012, $4 million and $8 million of cash posted as collateral were netted against Liabilities from risk management activities on our consolidated balance sheets.

(2) Includes cash of $1 million related to Genco as of December 31, 2013.

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

Collateral postings decreased from December 31, 2012 to December 31, 2013 primarily due to new first lien contracts for fuel and other commodity purchases being executed with counterparties, amending our contractual service agreements, a reduction in collateral from tolling agreements, a reduction in collateral supporting our DNE operations and overall changes in our commercial activity.

The fair value of our derivatives collateralized by first priority liens included liabilities of $145 million and $100 million at December 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.

Investing Activities

Capital Expenditures. We had capital expenditures of approximately $98 million during the year ended December 31, 2013 and $46 million, $63 million and $196 million during the 2012 Successor Period, the 2012 Predecessor Period and the year ended December 31, 2011, respectively. Our capital spending by reportable segment was as follows:

	Successor		Predecessor	
(amounts in millions)	Year Ended December 31 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012	Year Ended December 31, 2011
Coal (1)	$42	$26	$33	$ 115
IPH	1	—	—	—
Gas	53	19	23	79
DNE	—	—	—	2
Other	2	1	7	—

Total	$98	$46	$63	$ 196

Table of Contents

(1) On September 1, 2011, we completed the DMG Transfer. On June 5, 2012, we completed the DMG Acquisition. Therefore, capital expenditures are included only from June 6, 2012 to October 1, 2012 for the 2012 Predecessor Period and from January 1, 2011 through August 31, 2011 for the year ended December 31, 2011. For the 2012 Predecessor Period and the year ended December 31, 2011, including the periods that Coal was not included in our consolidated financial statements, Coal capital expenditures were $75 million and $184 million, respectively.

Capital spending in our Coal segment primarily consisted of environmental and maintenance capital projects. Capital spending in our IPH segment primarily consisted of environmental capital projects. Capital spending in our Gas segment primarily consisted of maintenance projects.

We expect capital expenditures for 2014 to be approximately $181 million, which is comprised of $46 million, $63 million, $66 million and $6 million in Coal, IPH, Gas and Other, respectively. The capital budget is subject to revision as opportunities arise or circumstances change.

In November 2012, we finished the Baldwin Unit 2 scrubber installation, marking the completion of the environmental capital compliance requirements under the Consent Decree. We spent approximately $923 million through December 31, 2013 and expect no material remaining costs in 2014 related to these Consent Decree projects.

Other Investing Activities. During the year ended December 31, 2013, there was a $335 million cash inflow related to restricted cash balances due to the release of cash collateral associated with the DPC LC and DMG LC facilities. A portion of these proceeds were used to repay in full and terminate commitments under the DMG and DPC credit agreements as further discussed below. As a result of repaying these credit agreements, all of our restricted cash was released. In addition, in connection with the AER Acquisition, we acquired $234 million in cash. Please read Note 3—Merger and Acquisitions for further discussion.

During the 2012 Successor Period, there was a $311 million cash inflow related to restricted cash balances due to a reduction in the Collateral Posting account. These proceeds were used to fund a portion of the repayment of the DMG and DPC Credit Agreement as further discussed below.

In connection with the DMG Acquisition on June 5, 2012, we acquired $256 million in cash and received $16 million in principal payments related to the Undertaking during the 2012 Predecessor Period. There was an $88 million cash inflow related to restricted cash balances associated with the DPC LC facilities and DPC Credit Agreement during the 2012 Predecessor Period. In addition, during the 2012 Predecessor Period, we requested the release of unused cash collateral related to the DPC LC facilities. These inflows were offset by a reduction of $22 million in cash as a result of the deconsolidation of the DNE Debtor Entities.

There was a $441 million cash outflow related to the DMG Transfer on September 1, 2011. There was a $222 million net cash inflow related to restricted cash balances during the year ended December 31, 2011 primarily due to increases of approximately $1 billion related to the repayment of our former Fifth Amended and Restated Credit Agreement, the Sithe Tender Offer and the return of collateral, partially offset by decreases of $792 million related to the DPC Credit Agreement, the DMG Credit Agreement and a Letter of Credit Reimbursement and Collateral Agreement. Cash outflows for purchases of short-term investments during the year ended December 31, 2011 totaled $244 million. Cash inflows related to maturities of short-term investments for the year ended December 31, 2011 totaled $419 million.

Other included $10 million of property insurance claim proceeds during the year ended December 31, 2011.

Financing Activities

Historical Cash Flow from Financing Activities. Cash flow used in financing activities totaled $154 million during the year ended December 31, 2013 due to (i) $1.913 billion in repayments of borrowings in full on the DMG and DPC Credit Agreements and the Tranche B-1 Term Loan, including $59 million in prepayment penalties associated with the early termination of the DMG and DPC Credit Agreements, (ii) $4 million in principal payments of borrowings on the Tranche B-2 Term Loan and (iii) $5 million in interest rate swap settlement payments during the fourth quarter 2013, offset by (i) $1.751 billion in proceeds from borrowings on the Credit Agreement and Senior Notes, net of financing costs and (ii) $17 million in proceeds associated with repurchase agreements related to emissions credits. Please read Note 12—Debt for further discussion.

Cash flow used in financing activities totaled $328 million during the 2012 Successor Period due to repayments of borrowings on the DMG and the DPC credit agreements.
Cash flow used in financing activities totaled $184 million for the 2012 Predecessor Period due to $200 million paid to unsecured creditors upon our emergence from bankruptcy on the Plan Effective Date and $11 million in repayments of borrowings on the DMG and the DPC credit agreements, offset by an increase of $27 million in connection with the recapitalization of Legacy Dynegy.

Table of Contents

Cash flow provided by financing activities totaled $375 million for the year ended December 31, 2011. Proceeds from long-term borrowings of $2 billion, net of $44 million of debt issuance costs, consisted of borrowing under the DPC Credit Agreement, DMG Credit Agreement and our former Fifth Amended and Restated Credit Agreement. These borrowings were partially offset by repayments of borrowings of $1.6 billion on our former Fifth Amended and Restated Credit Agreement, Sithe senior debt and our 6.875 percent senior notes.

Summarized Debt and Other Obligations. The following table depicts our third party debt obligations, and the extent to which they are secured as of December 31, 2013 and 2012:

(amounts in millions)	December 31, 2013	December 31, 2012
Dynegy:		
Secured obligations	$ 796	$ 1,354
Unsecured obligations	500	—
Emissions Repurchase Agreements	17	—
Unamortized (discount)/premium	(4)	61
Genco:		
Unsecured obligations	825	—
Unamortized discount	(142)	—
Total long-term debt	$ 1,992	$ 1,415

Financing Trigger Events. Our debt instruments and certain of our other financial obligations and all the Genco Senior Notes include provisions which, if not met, could require early payment, additional collateral support or similar actions. The trigger events include the violation of covenants (including, in the case of the Credit Agreement under certain circumstances, the senior secured leverage ratio covenant discussed below), defaults on scheduled principal or interest payments, including any indebtedness to the extent linked to it by reason of cross-default or cross-acceleration provisions, insolvency events, acceleration of other financial obligations and, in the case of the Credit Agreement, change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events.

Financial Covenants

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

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

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

Our revolver usage at December 31, 2013 was 33 percent of the aggregate revolver commitment due to outstanding letters of credit; therefore, we were required to test the covenant. Based on the calculation outlined in the Credit Agreement, we are in compliance at December 31, 2013.

Table of Contents

Genco Senior Notes. On December 2, 2013, in connection with the AER Acquisition, Genco Senior Notes remained outstanding as an obligation of Genco, a subsidiary of IPH. Genco's indenture includes provisions that require Genco to maintain certain interest coverage and debt-to-capital ratios in order for Genco to pay dividends, to make principal or interest payments on subordinated borrowings, to make loans to or investments in affiliates or to incur additional external, third-party indebtedness.

The following table summarizes these required ratios:

	Required Ratio
Restricted payment interest coverage ratio (1)	≥1.75
Additional indebtedness interest coverage ratio	≥2.50
Additional indebtedness debt-to-capital ratio	≤60%

(1) As of the date of the restricted payment, as defined, the minimum ratio must have been achieved for the most recently ended four fiscal quarters and projected by management to be achieved for each of the subsequent four six-month periods.

Based on December 31, 2013 results, Genco's interest coverage ratios are less than the minimum ratios required for Genco to pay dividends and borrow additional funds from external, third-party sources. Based on our projections, we expect that Genco's interest coverage ratios will be less than the minimum ratios required for Genco to pay dividends and incur additional third-party indebtedness until at least 2016.

Please read Note 12—Debt for further discussion.

Dividends on Common Stock. We have paid no cash dividends on our common stock and have no current intention of doing so. Any future determinations to pay cash dividends will be at the discretion of our Board of Directors, subject to applicable limitations under Delaware law, and will be dependent upon our results of operations, financial condition, contractual restrictions and other factors deemed relevant by our Board of Directors.

Credit Ratings

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

	Moody's	Standard & Poor's
Dynegy Inc.:		
Corporate Family Rating	B2	B
Senior Secured	B1	BB-
Senior Unsecured	B3	B+
Genco:		
Senior Unsecured	B3	CCC+

Disclosure of Contractual Obligations

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

Table of Contents

The following table summarizes the contractual obligations of the Company and its consolidated subsidiaries as of December 31, 2013. Cash obligations reflected are not discounted and do not include accretion or dividends.

	Expiration by Period				
(amounts in millions)	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Long-term debt (including current portion)	$2,138	$14	$27	$316	$1,781
Interest payments on debt	1,241	146	278	275	542
Coal commitments	691	357	287	47	—
Coal transportation	323	42	60	63	158
Operating leases	53	18	18	7	10
Gas transportation payments	126	37	39	25	25
Interconnection obligations	14	1	2	2	9
Contractual service agreements (1)	136	22	82	32	—
Pension funding obligations	100	4	20	38	38
Other obligations	42	32	4	2	4
Total contractual obligations	$4,864	$673	$817	$807	$2,567

(1) The table above includes projected payments through 2018 assuming the contracts remain in full force and effect; however, we currently estimate these agreements will be in effect for a period of 15 or more years. Our minimum obligation related to these agreements is limited to the termination payments.

Long-Term Debt (Including Current Portion). Long-term debt includes amounts related to the Senior Notes, the Credit Agreement, the Genco Senior Notes and the Emissions Repurchase Agreements. Amounts do not include unamortized discounts. Please read Note 12—Debt for further discussion.

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

Coal Commitments. At December 31, 2013, our subsidiaries had contracts in place to purchase coal for various generation facilities. The amounts in the table reflect our minimum purchase obligations. To the extent forecasted volumes have not been priced but are subject to a price collar structure, the obligations have been calculated using the minimum purchase price of the collar.

Coal Transportation. At December 31, 2013, we had long-term coal transportation contracts in place. We also had long-term rail car leases in place. The amounts included in Coal transportation reflect our minimum purchase obligations based on the terms of the contracts.

Operating Leases. Operating leases include minimum lease payment obligations associated with office and office equipment leases. Also included in operating leases are two charter agreements related to VLGCs previously utilized in our former global liquids business. The primary term of one charter expired at the end of September 2013 but will be extended for a second consecutive year. The primary term of the second charter is through September 2014 but will be extended for a period of one year at the sole option of the counterparty. 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 ended December 31, 2014 and 2015, respectively. To date, the subsidiary of Transammonia Inc. has complied with the terms of the sub-charter agreement.

Gas Transportation Payments. Gas transportation payments include fixed capacity obligations totaling approximately $126 million associated with fuel procurement for our Gas plants.

Interconnection Obligations. Interconnection obligations represent an obligation with respect to interconnection services for the Ontelaunee facility. This agreement expires in 2027. The obligation under this agreement is approximately $1 million per year through the term of the contract.

Contractual Service Agreements. Contractual service agreements represent obligations with respect to long-term plant maintenance agreements. In June 2013, we amended our maintenance agreements. The amendments substantially reduced collateral postings, restructured and reduced maintenance costs, extended the term of the agreements, decreased our risk from a catastrophic turbine failure and included technology upgrades for our equipment. We currently estimate these agreements will be

Table of Contents

in effect for a period of 15 or more years. The table above includes our current estimate of payments under the contracts through 2018 based on anticipated timing of outages and are subject to change as outage dates move. As of December 31, 2013, our minimum obligation with respect to these agreements is limited to the termination payments, which are approximately $149 million and $218 million in the event all contracts are terminated by us or the counterparty, respectively. Please read Note 16—Commitments and Contingencies—Other Commitments and Contingencies for further discussion.

Pension Funding Obligations. Amounts include our minimum required contributions to our defined benefit pension plans through 2023 as determined by our actuary and are subject to change based on actual results of the plan. We may elect to make voluntary contributions in 2014 which would decrease future funding obligations. Please read Note 18—Employee Compensation, Savings, Pension and Other Post-Employment Benefit Plans—Pension and Other Post-Employment Benefits—Obligations and Funded Status for further discussion.

Other Obligations. Other obligations primarily include the following items:

- Demolition and restoration obligations related to our retired power generation facilities of $17 million;
- Severance and retention obligations of $12 million as of December 31, 2013 in connection with a reduction in workforce and the closure of certain power generation facilities. Please read Note 24—Restructuring Charges for further discussion.
- Obligations of $4 million for harbor support and utility work in connection with Moss Landing;
- Obligations of $4 million related to information technology-related contracts;
- Obligations of $3 million primarily for Morro Bay city improvements in connection with our Morro Bay facility; and
- Obligations of $2 million primarily for a water supply agreement and other contracts for our Ontelaunee facility.

Commitments and Contingencies

Please read Note 16—Commitments and Contingencies, which is incorporated herein by reference, for further discussion of our material commitments and contingencies.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2013.

Table of Contents

RESULTS OF OPERATIONS

Overview and Discussion of Comparability of Results. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the year ended December 31, 2013, the 2012 Successor Period, the 2012 Predecessor Period and the year ended December 31, 2011. At the end of this section, we have included our business outlook for each segment.

We report the results of our power generation business primarily as three separate segments in our consolidated financial statements: (i) Coal, (ii) IPH and (iii) 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, IPH 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 for all periods presented.

On December 2, 2013, we completed the AER Acquisition. Therefore, the results of our IPH segment are included in our 2013 consolidated results for the period of December 2, 2013 through December 31, 2013. Please read Note 3—Merger and Acquisitions—AER Transaction Agreement for further discussion.

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. 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. Please read Note 21—Emergence from Bankruptcy and Fresh-Start Accounting for further discussion.

For financial reporting purposes, close of business on October 1, 2012, represents the date of our emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

“Predecessor”	The Company, pre-emergence from bankruptcy
“2012 Predecessor Period”	The Company’s operations, January 1, 2012 — October 1, 2012
“Successor”	The Company, post-emergence from bankruptcy
“2012 Successor Period”	The Company’s operations, October 2, 2012 — December 31, 2012

On September 1, 2011, we completed the DMG Transfer. Therefore, the results of our Coal segment (including DMG) were included in our 2011 consolidated results for the period of January 1, 2011 through August 31, 2011. Additionally, on June 5, 2012, we reacquired DMG through the DMG Acquisition. Therefore, the results of our Coal segment (including DMG) are included in our 2012 consolidated results for the period of June 6, 2012 through December 31, 2012.

Table of Contents

Consolidated Summary Financial Information—Year Ended December 31, 2013, 2012 Successor Period, 2012 Predecessor Period and Year Ended December 31, 2011

The following table provides summary financial data regarding our consolidated results of operations for the year ended December 31, 2013, the 2012 Successor Period, the 2012 Predecessor Period and the year ended December 31, 2011, respectively:

(amounts in millions)	Successor Year Ended December 31, 2013	October 2 Through December 31, 2012	Predecessor January 1 Through October 1, 2012	Year Ended December 31, 2011
Revenues	$1,466	$312	$981	$1,333
Cost of sales	(1,145)	(268)	(662)	(866)
Gross margin, exclusive of depreciation shown separately below	321	44	319	467
Operating and maintenance expense, exclusive of depreciation shown separately below	(308)	(81)	(148)	(254)
Depreciation expense	(216)	(45)	(110)	(295)
Other charges	—	—	—	(5)
Gain on sale of assets, net	2	—	—	—
General and administrative expense	(97)	(22)	(56)	(102)
Acquisition and integration costs	(20)	—	—	—
Operating income (loss)	(318)	(104)	5	(189)
Bankruptcy reorganization items, net	(1)	(3)	1,037	(52)
Earnings from unconsolidated investments	2	2	—	—
Interest expense	(97)	(16)	(120)	(348)
Loss on extinguishment of debt	(11)	—	—	(21)
Impairment of Undertaking receivable, affiliate	—	—	(832)	—
Other income and expense, net	8	8	31	35
Income (loss) from continuing operations before income taxes	(417)	(113)	121	(575)
Income tax benefit (Note 14)	58	—	9	144
Income (loss) from continuing operations	(359)	(113)	130	(431)
Income (loss) from discontinued operations, net of taxes	3	6	(162)	(509)
Net loss	(356)	(107)	(32)	(940)
Less: Net income (loss) attributable to noncontrolling interests	—	—	—	—
Net loss attributable to Dynegy Inc.	$(356)	$(107)	$(32)	$(940)

Table of Contents

The following tables provide summary financial data regarding our operating income (loss) by segment for the year ended December 31, 2013, the 2012 Successor Period, the 2012 Predecessor Period and the year ended December 31, 2011, respectively:

	Successor				
	Year Ended December 31, 2013				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Revenues	$467	$67	$932	$—	$1,466
Cost of sales	(459)	(46)	(640)	—	(1,145)
Gross margin, exclusive of depreciation shown separately below	8	21	292	—	321
Operating and maintenance expense, exclusive of depreciation expense shown separately below	(167)	(15)	(125)	(1)	(308)
Depreciation expense	(50)	(3)	(160)	(3)	(216)
Gain on sale of assets, net	2	—	—	—	2
General and administrative expense	—	—	—	(97)	(97)
Acquisition and integration costs (1)	—	(20)	—	—	(20)
Operating income (loss)	$(207)	$(17)	$7	$(101)	$(318)

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

	Successor			
	October 2 Through December 31, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$107	$205	$—	$312
Cost of sales	(110)	(158)	—	(268)
Gross margin, exclusive of depreciation shown separately below	(3)	47	—	44
Operating and maintenance expense, exclusive of depreciation and expense shown separately below	(38)	(42)	(1)	(81)
Depreciation expense	(8)	(36)	(1)	(45)
General and administrative expense	—	—	(22)	(22)
Operating loss	$(49)	$(31)	$(24)	$(104)

	Predecessor			
	January 1 Through October 1, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$166	$815	$—	$981
Cost of sales	(161)	(501)	—	(662)
Gross margin, exclusive of depreciation shown separately below	5	314	—	319
Operating and maintenance expense, exclusive of depreciation expense shown separately below	(55)	(95)	2	(148)
Depreciation expense	(13)	(91)	(6)	(110)
General and administrative expense	—	—	(56)	(56)
Operating income (loss)	$(63)	$128	$(60)	$5

Table of Contents

	Predecessor			
	Year Ended December 31, 2011			
(amounts in millions)	Coal	Gas	Other	Total
Revenues	$460	$872	$1	$1,333
Cost of sales	(237)	(629)	—	(866)
Gross margin, exclusive of depreciation shown separately below	223	243	1	467
Operating and maintenance expense, exclusive of depreciation shown separately below	(105)	(148)	(1)	(254)
Depreciation expense	(156)	(132)	(7)	(295)
Other charges	—	—	(5)	(5)
General and administrative expense	—	—	(102)	(102)
Operating loss	$(38)	$(37)	$(114)	$(189)

Discussion of Consolidated Results of Operations

Successor

Revenues. During the year ended December 31, 2013, revenues were $1,466 million. Revenues for the year were primarily the result of $1,233 million in power revenues with contributions of $519 million, $65 million and $649 million from the Coal, IPH and Gas segments, respectively. These revenues were associated with 20 million MWh, 2 million MWh and 16 million MWh of power generation during the year by the Coal, IPH and Gas segments, respectively. Also contributing to revenue was $162 million in capacity revenue, $39 million in tolling revenue, $46 million in ancillary and other revenue and $88 million in gas revenue, each primarily generated by the Gas segment. These contributions were offset by mark-to-market losses of $38 million consisting of $26 million, $8 million and $4 million in the Coal, IPH and Gas segments, respectively, as well as $64 million in negative financial settlements.

During the 2012 Successor Period, revenues were $312 million. Revenues for the period were primarily the result of $223 million in power revenues with contributions of $105 million and $118 million from the Coal and Gas segments, respectively. These revenues were associated with 5 million MWh and 4 million MWh of power generation during the period by the Coal and Gas segments, respectively. Also contributing to revenue was $31 million in capacity revenue, $11 million in tolling revenue, $8 million in ancillary and other revenue and $49 million in gas revenue, each primarily generated by the Gas segment. Additionally, revenues included $6 million and $39 million in mark-to-market gains from the Coal and Gas segments, respectively. These contributions were offset by $55 million in settlement losses due to the negative settlement of legacy put options, primarily in the Gas segment.

Cost of Sales. During the year ended December 31, 2013, cost of sales was $1,145 million. Cost of sales for the year primarily consisted of $640 million in Gas segment fuel costs which consist primarily of natural gas purchase and transportation costs and $459 million in Coal segment fuel costs and $46 million in IPH segment fuel costs which all consist of primarily coal purchase and transportation costs.

During the 2012 Successor Period, costs of sales were $268 million. Cost of sales for the period primarily consisted of $158 million in Gas segment fuel costs, which consist primarily of natural gas purchase and transportation costs, and $110 million in Coal segment fuel costs, which consist primarily of coal purchase and transportation costs.

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. During the year ended December 31, 2013, operating and maintenance expense was $308 million. Operating and maintenance expense for the period primarily consisted of labor, direct operating and maintenance costs related to our facilities, outage costs related to planned and unplanned outages and other costs, which include fuel handling and environmental costs. The Coal segment accounted for $167 million, the IPH segment accounted for $15 million, the Gas segment accounted for $125 million and Other accounted for $1 million.

During the 2012 Successor Period, operating and maintenance expense was $81 million. Operating and maintenance expense for the period primarily consisted of labor, direct operating and maintenance costs related to our facilities, outage costs related to planned and unplanned outages and other costs, which include fuel handling and environmental costs. Operating and maintenance expense for the period was $38 million for the Coal segment, $42 million for the

Gas segment and $1 million in Other.

Depreciation Expense. During the year ended December 31, 2013, depreciation expense was $216 million. Depreciation expense for the period was $50 million for the Coal segment, $3 million for the IPH segment, $160 million for the Gas segment and $3 million for Other.

Table of Contents

During the 2012 Successor Period, depreciation expense was $45 million. Depreciation expense for the period was $8 million for the Coal segment, $36 million for the Gas segment and $1 million for Other. As part of fresh-start accounting on October 1, 2012, our fixed assets were recorded at fair value and this new basis will be depreciated over the remaining useful lives.

General and Administrative Expense. During the year ended December 31, 2013, general and administrative expense was $97 million. General and administrative expense for the period primarily consisted of $72 million in labor and benefit costs, $7 million in legal and professional fees, $5 million in insurance costs, $3 million in office leases and $10 million in office expenses and other costs.

During the 2012 Successor Period, general and administrative expense was $22 million. General and administrative expense for the period primarily consisted of $16 million in labor and benefit costs, $1 million in professional service fees and $5 million in office expenses and other costs.

Acquisition and Integration Costs. During the year ended December 31, 2013, acquisition and integration costs were $20 million, which were incurred in connection with the AER Acquisition and consisted of $9 million in severance expenses, $7 million in legal and consulting fees and $4 million in other costs. Please read Note 3—Merger and Acquisitions for further discussion.

Interest Expense. During the year ended December 31, 2013, interest expense was $97 million. Interest expense primarily consisted of (i) $24 million and $15 million in interest on the DPC and DMG credit agreements, respectively, which were terminated in April 2013, (ii) $22 million in interest expenses on the Tranche B-2 Term Loan, (iii) $18 million in interest expense on the Senior Notes, (iv) $5 million in interest expense on the Genco Senior Notes, (v) $7 million in mark-to-market gains on interest rate swaps, (vi) $5 million in fees related to the Revolving Facility and (vii) $1 million in interest expense on the Tranche B-1 Term Loan, which was terminated on May 20, 2013.

During the 2012 Successor Period, interest expense was $16 million. Interest expense primarily consisted of $22 million and $13 million of interest on the DPC and DMG credit agreements, respectively, partially offset by $3 million in amortization of the premium and $16 million in accelerated amortization of the premium related to the early repayment of $325 million, in aggregate, of the DPC and DMG credit agreements.

Please read Note 12—Debt for further discussion.

Loss on Extinguishment of Debt. During the year ended December 31, 2013, loss on extinguishment of debt totaled $11 million. The loss was incurred in connection with the termination of the DPC and DMG credit agreements and the Term Loan B-1. The amount is comprised of (i) a prepayment penalty of approximately $59 million, (ii) $2 million for the accelerated amortization of the discount on the Term Loan B-1 and (iii) $6 million in accelerated amortization of debt issuance costs related to the DPC Revolving Credit Facility and the Term Loan B-1, offset by (iv) $56 million in non-cash gains for the accelerated amortization of the remaining premium related to the DPC and DMG credit agreements. Please read Note 12—Debt for further discussion.

Other Income and Expense, Net. During the year ended December 31, 2013, other income and expense, net was an $8 million gain, which primarily consisted of insurance proceeds, partially offset by a change in the fair value of our common stock warrants issued upon emergence from bankruptcy in October 2012.

During the 2012 Successor Period, other income and expense, net was an $8 million gain due to change in the fair value of our common stock warrants issued upon emergence from bankruptcy in October 2012.

Income Tax Benefit. We reported an income tax benefit of $58 million and zero for the year ended December 31, 2013 and the 2012 Successor Period, respectively. The effective tax rate for the year ended December 31, 2013 and the 2012 Successor Period was 14 percent and zero percent, respectively.

For the year ended December 31, 2013, the difference between the effective rate of 14 percent and the statutory rate of 35 percent resulted primarily due to a change in our valuation allowance. During 2013, we recognized a tax benefit of $32 million in continuing operations for pre-tax income from components other than continuing operations that resulted in a reduction of the valuation allowance. In addition, a tax benefit of $35 million was also recognized in continuing operations that resulted from the tax impact of the AER Acquisition which also reduced our valuation allowance. The benefit of these valuation allowance adjustments was partially offset by $9 million of tax expense associated with current federal and state taxes. As of December 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 2012 Successor Period, 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.

Please read Note 14—Income Taxes for further discussion.

Table of Contents

Income from Discontinued Operations, Net of Tax. During the year ended December 31, 2013, income from discontinued operations, net of tax was $3 million. Income from discontinued operations primarily consisted of a $7 million DNE pension curtailment gain due to the termination of a majority of the Danskammer employees and closing the Roseton sale, partially offset by a $2 million loss related to legacy capacity contracts executed with the Roseton facility which terminated upon the sale of the facility and $2 million in tax expense.

During the 2012 Successor Period, income from discontinued operations, net of tax was $6 million, which related to the release of a franchise tax liability related to our former midstream business on which the statute of limitations expired.

Please read Note 23—Dispositions and Discontinued Operations for further discussion.

Predecessor

Revenues. During the 2012 Predecessor Period, revenues were $981 million. Revenues for the period were primarily the result of $675 million in power revenues with contributions of $183 million and $492 million from the Coal and Gas segments, respectively. These revenues were associated with 7 million MWh and 17 million MWh of power generation during the period by the Coal and Gas segments, respectively. Also contributing to revenue was $166 million in capacity revenues primarily in the Gas segment, $117 million in mark-to-market gains in the Gas segment, partially offset by $14 million in Coal segment mark-to-market losses. Additionally, revenues include $100 million in natural gas revenue, $79 million in tolling revenues, and $34 million of ancillary and other revenue, each primarily generated by the Gas segment. These contributions were offset by negative financial settlements of $7 million for the Coal segment and $169 million for the Gas segment primarily due to legacy put options.

During the year ended December 31, 2011, revenues were $1,333 million. Revenues for the period were primarily the result of $1,000 million in power revenues with contributions of $512 million and $488 million from the Coal and Gas segments, respectively. These revenues were associated with 16 million MWh and 12 million MWh of power generation during the period by the Coal and Gas segments, respectively. Also contributing to the revenue total was $221 million in capacity revenue, $131 million in tolling revenue, $44 million in ancillary and other revenue, and $197 million in gas revenue, each primarily generated by the Gas segment. These contributions were offset by mark-to-market losses of $76 million, $67 million and $4 million from the Coal, Gas and Other segments, respectively, and $113 million in negative financial settlements, primarily related to the Gas segment.

Cost of Sales. During the 2012 Predecessor Period, cost of sales was $662 million. Cost of sales for the period primarily consisted of $501 million in Gas segment fuel costs which consist primarily of natural gas purchase and transportation costs and $161 million in Coal segment fuel costs which consist primarily of coal commodity and transportation costs. These costs were driven by power generation during the period discussed above.

During the year ended December 31, 2011, cost of sales was $866 million. Cost of sales for the period primarily consisted of $629 million in Gas segment fuel costs which consist primarily of natural gas purchase and transportation costs and $237 million in Coal segment fuel costs which consist primarily of coal commodity and transportation costs. These costs were driven by power generation during the period discussed above.

Operating and Maintenance Expense, Exclusive of Depreciation Shown Separately Below. During the 2012 Predecessor Period, operating and maintenance expense was $148 million. Operating and maintenance expense for the period primarily consisted of labor, direct operating and maintenance costs related to our facilities, outage costs related to planned and unplanned outages and other costs, which include fuel handling and environmental costs. Operating and maintenance expense for the period primarily consisted of $55 million in the Coal segment, $95 million in the Gas segment.

During the year ended December 31, 2011, operating and maintenance expense was $254 million. Operating and maintenance expense for the period primarily consisted of labor, direct operating and maintenance costs related to our facilities, outage costs related to planned and unplanned outages and other costs, which include fuel handling and environmental costs. Operating and maintenance expense for the period primarily consisted of $105 million in the Coal segment, $148 million in the Gas segment and $1 million in Other.

Depreciation Expense. During the 2012 Predecessor Period, depreciation expense was $110 million. Depreciation expense was $13 million for the Coal segment, $91 million for the Gas segment and $6 million for Other.

Depreciation expense for the period primarily consisted of the allocation of the historical costs of our assets over their useful lives and was partially offset by a reduction in our asset retirement obligations associated with the South Bay facility.

During the year ended December 31, 2011, depreciation expense was $295 million. Depreciation expense was $156 million for the Coal segment, $132 million for the Gas segment and $7 million for Other. Depreciation expense for the period primarily consisted of the allocation of the historical costs of our assets over their useful lives.

Other Charges. During the year ended December 31, 2011, other charges were $5 million, which primarily consisted of restructuring costs.
General and Administrative Expense. During the 2012 Predecessor Period, general and administrative expense was $56 million. General and administrative expense for the period primarily consisted of $50 million in labor and benefit costs and $6 million in legal and professional fees and other costs.
During the year ended December 31, 2011, general and administrative expense was $102 million. General and administrative expense for the period primarily consisted of $66 million in labor and benefit costs, $29 million in legal and professional fees and $7 million in office expenses and other costs.
Bankruptcy Reorganization Items, net. During the 2012 Predecessor Period, bankruptcy reorganization items, net were a gain of $1,037 million. Bankruptcy reorganization items, net consisted of a pre-tax gain of $1,197 million related to the settlement of liabilities subject to compromise as a result of emergence from bankruptcy, a reduction of $161 million and $10 million in the estimated allowable claims related to the subordinated debt and other items, respectively, and a $17 million change in the value of the Administrative Claim. The gains were offset by $299 million in fresh-start adjustments primarily due to the adjustment of assets and liabilities to fair value as a result of the application of fresh-start accounting and $49 million related to the write-off of deferred financing costs and debt discount related to our long-term debt.
During the year ended December 31, 2011, bankruptcy reorganization items, net were a loss of $52 million. Bankruptcy reorganization items, net primarily consisted of the write-off of deferred financing costs related to our unsecured notes and debentures and costs related to our bankruptcy advisors.
Please read Note 21—Emergence from Bankruptcy and Fresh-Start Accounting for further discussion.
Interest Expense. During the 2012 Predecessor Period, interest expense was $120 million. Interest expense primarily consisted of (i) $77 million and $19 million in interest on the DPC and DMG credit agreements, respectively, (ii) $23 million in mark-to-market gains on interest rate swaps, (iii) $4 million in amortization of financing costs and (iv) $2 million in commitment and other fees, offset by $5 million in capitalized interest related to the Coal segment Consent Decree.
During the year ended December 31, 2011, interest expense was $348 million, which primarily consisted of (i) $243 million in interest on our notes and debentures prior to the bankruptcy filing on November 7, 2011, (ii) $56 million and $4 million in interest on the DPC and DMG credit agreements, respectively, (iii) $23 million in interest on Letter of Credit and Revolving Facilities, (iv) $22 million in amortization of financing costs, (v) $7 million in mark-to-market gains on interest rate swaps and (vi) $5 million in commitment fees, offset by $12 million in capitalized interest related to the Coal segment Consent Decree.
Loss on Extinguishment of Debt. During the year ended December 31, 2011, loss on extinguishment of debt was $21 million, which was incurred in connection with the termination of the Sithe senior debt.
Impairment of Undertaking Receivable, affiliate. During the 2012 Predecessor Period, impairment of Undertaking receivable, affiliate was $832 million. 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. The Undertaking was settled upon execution of the Settlement Agreement.
Please read Note 3—Merger and Acquisitions—DMG Transfer and DMG Acquisition for further discussion.
Other Income and Expense, net. During the 2012 Predecessor Period, other income and expense, net was a gain of $31 million. Other income and expense, net primarily consisted of $24 million of interest income on the Undertaking receivable, affiliate, a $5 million distribution received related to our retained profits interest in Plum Point and $2 million in certain insurance proceeds.
During the year ended December 31, 2011, other income and expense, net was a gain of $35 million. Other income and expense, net primarily consisted of interest income on the Undertaking receivable, affiliate.
Income Tax Benefit. We reported an income tax benefit of $9 million for the 2012 Predecessor Period compared to an income tax benefit of $144 million for the year ended December 31, 2011. The effective tax rate for the 2012

Predecessor Period was seven percent compared to 25 percent for the year ended December 31, 2011.
For the 2012 Predecessor Period, the difference between the effective rates of seven 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.

Table of Contents

For the year ended December 31, 2011, the difference between the effective rate of 25 percent and the statutory rate of 35 percent is primarily due to the impact of state taxes partially offset by a change in our valuation allowance.
Loss from Discontinued Operations, Net of Tax. During the 2012 Predecessor Period, loss from discontinued operations, net of tax was $162 million. Loss from discontinued operations, net of tax primarily related to Bankruptcy reorganization items, net, which included a $395 million charge related to the estimated claim for the rejection of the DNE Facilities Lease and $5 million in other charges, partially offset by a gain of $217 million on the settlement of the DNE lease guaranty claim and a $43 million gain on the deconsolidation of the DNE Entities. Additionally the loss from discontinued operations consisted of $22 million related to the DNE operations.
For the year ended December 31, 2011, loss from discontinued operations, net of tax was $509 million, which primarily consisted of DNE operations.
Discussion of Adjusted EBITDA
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 certain assets, (ii) the impacts of mark-to-market changes on derivatives related to our generation portfolio, as well as interest rate swaps and warrants, (iii) the impact of impairment charges and certain other costs such as those associated with the acquisition of AER, internal reorganization and bankruptcy proceedings, (iv) income or loss associated with discontinued operations and (v) income or expense on up front premiums received or paid for financial options in periods other than the strike periods. Our Adjusted EBITDA for the year ended December 31, 2011 is based on our prior methodology which did not include (i) adjustments for up front premiums, (ii) mark-to-market adjustments for financial activity not related to our generation portfolio or (iii) the elimination of income or loss associated with discontinued operations. Adjusted EBITDA includes the Adjusted EBITDA for 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. Adjusted EBITDA is meant to reflect the operating performance of our entire power generation fleet for the period presented; consequently, it excludes the impact of mark-to-market accounting, impairment charges, gains and losses on sales of assets, and other items that could be considered "non-operating" or "non-core" in nature. Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers and evaluate overall financial performance, we believe they provide useful information for our investors. In addition, many analysts, fund managers, and other stakeholders that communicate with us typically request our financial results in an EBITDA and Adjusted EBITDA format.
As prescribed by the SEC, when 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).

Table of Contents

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the year ended December 31, 2013:

	Successor				
	Year Ended December 31, 2013				
(amounts in millions)	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$(356)
Income from discontinued operations, net of tax					(3)
Income tax benefit					(58)
Bankruptcy reorganization items, net					1
Interest expense					97
Loss on extinguishment of debt					11
Earnings from unconsolidated investments					(2)
Other items, net					(8)
Operating income (loss)	$(207)	$(17)	$7	$(101)	$(318)
Depreciation expense	50	3	160	3	216
Bankruptcy reorganization items, net	—	—	—	(1)	(1)
Amortization of intangible assets and liabilities	126	(2)	127	—	251
Earnings from unconsolidated investments	—	—	2	—	2
Other items, net	—	—	2	6	8
EBITDA	(31)	(16)	298	(93)	158
Bankruptcy reorganization items, net	—	—	—	1	1
Acquisition and integration costs	—	20	—	—	20
Mark-to-market loss, net	25	8	4	—	37
Change in fair value of common stock warrants	—	—	—	1	1
Restructuring costs and other expenses	—	—	—	8	8
Other	2	—	—	—	2
Adjusted EBITDA	$(4)	$12	$302	$(83)	$227

Table of Contents

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the year ended December 31, 2012, which includes the 2012 Successor and 2012 Predecessor periods:

	Combined (2) Year Ended December 31, 2012			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(139)
Loss from discontinued operations, net of tax				156
Income tax benefit				(9)
Impairment of Undertaking receivable, affiliate				832
Bankruptcy reorganization items, net				(1,034)
Interest expense				136
Earnings from unconsolidated investments				(2)
Other items, net				(39)
Operating income (loss)	$(112)	$97	$(84)	$(99)
Impairment of Undertaking receivable, affiliate	—	—	(832)	(832)
Bankruptcy reorganization items, net	—	—	1,034	1,034
Depreciation expense	21	127	7	155
Amortization of intangible assets and liabilities	78	61	—	139
Earnings from unconsolidated investments	—	2	—	2
Other items, net	5	2	32	39
EBITDA	(8)	289	157	438
Impairment of Undertaking receivable, affiliate	—	—	832	832
Bankruptcy reorganization items, net	—	—	(1,034)	(1,034)
Interest income on Undertaking receivable	—	—	(24)	(24)
Restructuring costs and other expense	—	—	3	3
Mark-to-market (gain) loss, net	7	(166)	—	(159)
Premium adjustment	1	(1)	—	—
Changes in fair value of common stock warrants	—	—	(8)	(8)
Adjusted EBITDA from Dynegy	—	122	(74)	48
Adjusted EBITDA from Legacy Dynegy (1)	20	—	(11)	9
Adjusted EBITDA	$20	$122	$(85)	$57

(1) Our 2012 consolidated results reflect the results of our accounting predecessor, DH. Therefore, the results of our Coal segment are not included in our consolidated results for the period from January 1, 2012 through June 5, 2012. However, we have included the Adjusted EBITDA related to the Coal segment for the period from January 1, 2012 through June 5, 2012 in this adjustment because it is part of our ongoing business and management uses Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

(2) For purposes of presenting Adjusted EBITDA for the year ended December 31, 2012, we combined the 2012 Successor Period and the 2012 Predecessor Period in order to reconcile our non-GAAP measure to its nearest comparable GAAP measure. The combined Successor and Predecessor periods are also non-GAAP due to fresh-start accounting. Therefore, the following table is provided to reconcile the combined amounts to the separate Successor and Predecessor periods.

Table of Contents

(amounts in millions)	Successor October 2 Through December 31, 2012	Predecessor January 1 Through October 1, 2012	Total
Net loss	$(107)	$(32)	$(139)
Loss from discontinued operations, net of tax	(6)	162	156
Income tax benefit	—	(9)	(9)
Impairment of Undertaking receivable, affiliate	—	832	832
Bankruptcy reorganization items, net	3	(1,037)	(1,034)
Interest expense	16	120	136
Earnings from unconsolidated investments	(2)	—	(2)
Other items, net	(8)	(31)	(39)
Operating income (loss)	(104)	5	(99)
Impairment of Undertaking receivable, affiliate	—	(832)	(832)
Bankruptcy reorganization items, net	(3)	1,037	1,034
Depreciation expense	45	110	155
Amortization of intangible assets and liabilities	60	79	139
Earnings from unconsolidated investments	2	—	2
Other items, net	8	31	39
EBITDA	$8	$430	$438

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the year ended December 31, 2011:

	Predecessor Year Ended December 31, 2011			
(amounts in millions)	Coal	Gas	Other	Total
Net loss				$(940)
Loss from discontinued operations, net of tax				509
Income tax benefit				(144)
Interest expense and debt extinguishment costs				369
Bankruptcy reorganization items, net				52
Other items, net				(35)
Operating loss	$(38)	$(37)	$(114)	$(189)
Bankruptcy reorganization items, net	—	—	(52)	(52)
Other items, net	2	2	31	35
Depreciation expense	156	132	7	295
EBITDA from continuing operations	120	97	(128)	89
Merger termination fee, restructuring costs and other expenses	(1)	7	25	31
Bankruptcy reorganization items, net	—	—	52	52
Mark-to-market loss, net	76	51	4	131
Adjusted EBITDA from Dynegy	195	155	(47)	303
Adjusted EBITDA from Legacy Dynegy (1)	48	—	(51)	(3)
Adjusted EBITDA from continuing operations	$243	$155	$(98)	$300
Adjusted EBITDA from discontinued operations				(19)
Adjusted EBITDA				$281

Table of Contents

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(1) Our 2011 consolidated results reflect the results of our accounting predecessor, DH. Therefore, the results of our Coal segment are not included in our consolidated results for the period from September 1, 2011 through December 31, 2011. However, we have included the Adjusted EBITDA related to the Coal segment for the period from September 1, 2011 through December 31, 2011 in this adjustment because it is part of our ongoing business and management uses Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

Adjusted EBITDA

Adjusted EBITDA increased by $170 million from $57 million for the year ended December 31, 2012 to $227 million for the year ended December 31, 2013. The increase was primarily related to an increase of $169 million in our Gas segment Adjusted EBITDA due to the absence of negative settlements associated with legacy commercial positions which adversely impacted 2012 results, $12 million of IPH Adjusted EBITDA for the month of December and $8 million of decreased operations and maintenance costs for our Coal and Gas segments. Offsetting these increases was a $19 million decrease in realized energy margin in our Coal segment due to lower realized prices on hedged generation.

Adjusted EBITDA decreased by $224 million from $281 million for the year ended December 31, 2011 to $57 million for the year ended December 31, 2012. The decrease is primarily due to lower overall market prices and an increase in basis differentials in our Coal segment, which resulted in a $183 million decrease in physical energy margin, $60 million in lower capacity and tolling revenues in our Gas segment due to a decrease in capacity pricing and the cancellation of the Morro Bay toll and Moss Landing resource adequacy contract and the settlement of legacy commercial positions, which resulted in $65 million in higher settlement expense in 2012 compared to 2011. Offsetting these decreases is a $39 million increase in energy margin in our Gas segment due to improved spark spreads and fewer outages and $57 million due to changes in methodology associated with amortization expense and no longer including DNE in Adjusted EBITDA in 2012 as a result of DNE being classified in discontinued operations. Adjusted EBITDA for 2011 includes amortization expense related to the Sithe acquisition and negative Adjusted EBITDA for DNE. These amounts were excluded in 2012.

Table of Contents

Discussion of Segment Adjusted EBITDA

Coal Segment. Both on-peak and off-peak power prices were higher in the year ended December 31, 2013 compared to the year ended December 31, 2012, resulting in higher gross margin. Both on-peak and off-peak power prices were lower in the year ended December 31, 2012 compared to the year ended December 31, 2011.

As a result of the DMG Acquisition, 2012 results only include the results of the Coal segment for the period June 6, 2012 through December 31, 2012. Additionally, as a result of the DMG Transfer, 2011 results only include the results of the Coal segment for the period January 1, 2011 through August 31, 2011. The following table provides summary financial data regarding our Coal segment results of operations for the year ended December 31, 2013, the 2012 Successor Period, the 2012 Predecessor Period and the year ended December 31, 2011, respectively.

(dollars in millions, except for price information)	Successor		Predecessor	
	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012	Year Ended December 31, 2011
Operating Revenues				
Energy	$519	$105	$184	$512
Mark-to-market gain (loss), net	(25)	7	(14)	(76)
Other (1)	(27)	(5)	(4)	24
Total operating revenues	467	107	166	460
Operating costs				
Cost of sales	(333)	(82)	(112)	(237)
Contract amortization	(126)	(28)	(49)	—
Total operating costs	(459)	(110)	(161)	(237)
Gross margin	8	(3)	5	223
Operating and maintenance expense	(167)	(38)	(55)	(105)
Depreciation expense	(50)	(8)	(13)	(156)
Gain on sale of assets, net	2	—	—	—
Operating loss	(207)	(49)	(63)	(38)
Depreciation expense	50	8	13	156
Amortization of intangible assets and liabilities	126	29	49	—
Other items, net	—	—	5	2
EBITDA	(31)	(12)	4	120
Mark-to-market (gain) loss, net	25	(6)	13	76
Other expenses	2	1	—	(1)
Adjusted EBITDA (2)	$(4)	$(17)	$17	$195
Million Megawatt Hours Generated (3)	20.4	4.7	6.6	15.6
In Market Availability for Coal Fired Facilities (4)	89%	86%	93%	92%
Average Quoted Market Power Prices ($/MWh) (5):				
On-Peak: Indiana (Indy Hub)	$38.04	$34.76	$39.72	$44.80
Off-Peak: Indiana (Indy Hub)	$27.50	$25.94	$23.88	$30.36

59

Table of Contents

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

(2) Legacy Dynegy's adjusted EBITDA was $20 million for the period January 1, 2012 through June 5, 2012 and $48 million for the period September 1, 2011 through December 31, 2011.

(3) Reflects production volumes in million MWh generated during the periods Coal was included in our consolidated results. Generation volumes were 19.9 million MWh and 22.2 million MWh for the full twelve months ended December 31, 2012 and 2011, respectively.

(4) Reflects the percentage of generation available during the period Coal was included in our consolidated results. In Market Availability for Coal Fired Facilities was 92 percent for the full twelve months ended December 31, 2012 and 2011.

(5) Reflects the average of day-ahead quoted prices for the periods Coal was included in our consolidated results and does not necessarily reflect prices we realized. The average of day-ahead quoted prices was $34.61 and $41.34 for the full twelve months ended December 31, 2012 and 2011, respectively.

(6) The market reference for 2011 was Cinergy (Cin Hub). At the end of 2011, the Cin Hub pricing point in MISO ceased to exist when the Ohio portion of the market point became part of PJM. Beginning in 2012, Indy Hub became MISO's major market point and is considered a direct correlation to the old Cin Hub and has been accepted as a replacement for Cin Hub in commercial contracts.

Operating loss for the year ended December 31, 2013 was $207 million, $49 million for the 2012 Successor Period, $63 million for the 2012 Predecessor Period and $38 million for the year ended December 31, 2011.

Adjusted EBITDA was a loss of $4 million for the year ended December 31, 2013, which was primarily comprised of $188 million in energy margin and $6 million in other items, offset by $31 million in settlement expense and $167 million in operating expense. Adjusted EBITDA was $20 million for the year ended December 31, 2012, which includes the 2012 Successor Period, the 2012 Predecessor Period and Legacy Dynegy, and was primarily comprised of $158 million in energy margin, $5 million in other items and $19 million in settlement revenue offset by $162 million in operating expenses.

Adjusted EBITDA was $243 million for the year ended December 31, 2011, which includes Legacy Dynegy, and was primarily comprised of $341 million in energy margin, $6 million in other items and $66 million in settlement revenue, offset by $170 million in operating expenses. The decrease in Adjusted EBITDA between 2013 and 2012 was primarily driven by lower realized prices on hedged positions while the decrease between 2012 and 2011 was primarily driven by lower overall realized prices.

Table of Contents

IPH Segment. The IPH segment includes the results of its wholesale and retail operations since the acquisition on December 2, 2013.

(dollars in millions, except for price information)	Successor Year Ended December 31, 2013
Operating Revenues	
Energy	$ 65
Mark-to-market loss, net	(8)
Contract amortization	(3)
Other (1)	13
Total operating revenues	67
Operating Costs	
Cost of sales	(51)
Contract amortization	5
Total operating costs	(46)
Gross margin	21
Operating and maintenance expense	(15)
Depreciation expense	(3)
Acquisition and integration costs	(20)
Operating loss	(17)
Depreciation expense	3
Amortization of intangible assets and liabilities	(2)
EBITDA	(16)
Mark-to-market loss, net	8
Acquisition and integration costs	20
Adjusted EBITDA	$ 12
Million Megawatt Hours Generated (2)	2.4
In Market Availability for Coal Fired Facilities (3)	90 %
Average Quoted Market Power Prices ($/MWh) (4):	
On-Peak: Indiana (Indy Hub)	$ 40.32
Off-Peak: Indiana (Indy Hub)	$ 30.82

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

(2) Reflects production volumes in million MWh generated during the period IPH was included in our consolidated results.

(3) Reflects the percentage of generation available during the period IPH was included in our consolidated results.

(4) Reflects the average of day-ahead quoted prices for the period IPH was included in our consolidated results and does not necessarily reflect prices we realized.

Operating loss for the year ended December 31, 2013 was $17 million. Adjusted EBITDA was income of $12 million for the year ended December 31, 2013, which consisted of energy margin and revenue from financial settlements, partially offset by operating expenses.

Gas Segment. Spark spreads were higher in the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily at our Moss Landing and Independence facilities. Spark spreads were also higher in the year ended December 31, 2012 compared to the year ended December 31, 2011 primarily at our Moss Landing, Independence and Kendall facilities.

61

Table of Contents

The following table provides summary financial data regarding our Gas segment results of operations for the year ended December 31, 2013, the 2012 Successor Period, the 2012 Predecessor Period and the year ended December 31, 2011, respectively:

	Successor		Predecessor	
(dollars in millions, except for price information)	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012	Year Ended December 31, 2011
Operating Revenues				
Energy	$649	$118	$492	$489
Capacity	237	50	194	257
Mark-to-market gain (loss), net	(4)	39	117	(61)
Contract amortization	(135)	(34)	(32)	(43)
Other (1)	185	32	44	230
Total operating revenues	932	205	815	872
Operating Costs				
Cost of sales	(648)	(160)	(504)	(634)
Contract amortization	8	2	3	5
Total operating costs	(640)	(158)	(501)	(629)
Gross margin	292	47	314	243
Operating and maintenance expense	(125)	(42)	(95)	(148)
Depreciation expense	(160)	(36)	(91)	(132)
Operating income (loss)	7	(31)	128	(37)
Depreciation expense	160	36	91	132
Amortization of intangible assets and liabilities	127	32	29	—
Earnings from unconsolidated investments	2	2	—	—
Other items, net	2	—	2	2
EBITDA	298	39	250	97
Mark-to-market (gain) loss, net	4	(39)	(127)	51
Premium adjustment	—	(2)	1	—
Other expenses	—	—	—	7
Adjusted EBITDA	$302	$(2)	$124	$155
Million Megawatt Hours Generated (2)	16.2	3.5	16.9	12.3
In Market Availability for Combined Cycle Facilities (3)	97%	83%	98%	94%
Average Capacity Factor for Combined Cycle Facilities (4)	43%	36%	57%	21%
Average Market On-Peak Spark Spreads ($/MWh) (5)	$15.71	$13.05	$15.04	$12.74
Average Market Off-Peak Spark Spreads ($/MWh) (5)	$3.50	$3.15	$4.71	$0.62
Average natural gas price—Henry Hub ($/MMBtu) (6)	$3.72	$3.39	$2.53	$3.99

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

(2)

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

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

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

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

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

Operating income for the year ended December 31, 2013 was $7 million, a loss of $31 million for the 2012 Successor Period, income of $128 million for the 2012 Predecessor Period and a loss of $37 million for the year ended December 31, 2011.

Adjusted EBITDA totaled $302 million during the year ended December 31, 2013, which was primarily comprised of $334 million of capacity and tolling revenue, $90 million of physical energy margin and $42 million of ancillary services and other items, offset by $125 million of operating expense and $39 million in negative financial settlements. Adjusted EBITDA was $122 million for the year ended December 31, 2012, which includes the 2012 Successor Period, the 2012 Predecessor Period and Legacy Dynegy, and was primarily comprised of $328 million of capacity and tolling revenue, $93 million of physical energy margin and $48 million of ancillary services and other items, offset by $209 million in negative financial settlements and $138 million of operating expense.

Adjusted EBITDA was $155 million for the year ended December 31, 2011, which includes Legacy Dynegy, and was primarily comprised of $388 million of capacity and tolling revenue, $47 million of physical energy margin and $50 million of ancillary services and other items, offset by $148 million of operating expense, $144 million in negative financial settlements and $38 million in amortization expense which was included in 2011 Adjusted EBITDA.

Outlook

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

Coal. The Coal segment consists of four plants, all located in the MISO region, and totaling 2,980 MW.

As of February 21, 2014, our Coal expected generation volumes are 51 percent hedged volumetrically for 2014 and approximately 10 percent hedged volumetrically for 2015. We plan to continue our hedging program for Coal over a one- to three-year period using various instruments, which includes the sale of natural gas swaps as a cross-commodity correlated hedge for our power revenue. As a result of the offsetting risks of our Coal and Gas segments, we are able to reduce the costs associated with hedging by executing a portion of Coal’s hedges with an internal affiliate. The internal hedges are cross-commodity hedges and we intend to expand this in the future. Beyond 2014, the portfolio is largely open, positioning Coal to benefit from possible future power market pricing improvements.

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

As of February 21, 2014, our expected coal requirements are 93 percent contracted and priced in 2014. Our forecasted coal requirements for 2015 are 68 percent contracted and 14 percent priced. Our coal transportation requirements are fully contracted and priced for the next several years. We continue to explore various alternative contractual commitments and financial options, as well as facility modifications, to ensure stable and competitive fuel supplies and to mitigate further supply risks for near- and long-term coal supplies.

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

MISO's annual Loss of Load Expectation ("LOLE") study was published in early November 2013. The LOLE study is a critical input to the annual MISO Planning Resource Auction ("PRA"). The LOLE study employed meaningful changes for the planning year 2014-2015 to reflect the integration of Entergy into MISO and to reflect modeling enhancements required to stabilize the planning reserve margin and reliability requirements in MISO. The LOLE also utilizes a revised methodology to calculate import and export capabilities between Local Resource Zones ("LRZ") which may have an impact on intra-zonal balances. On February 6, 2014, MISO announced revisions to its November 2013 LOLE analysis. These revisions impacted LRZ 4 and 5

Table of Contents

(where our facilities are located). The planning year 2014-2015 MISO auction will take place in late March, with results expected to be released no later than April 15, 2014.

Based on analysis of historical constraints near our generating facilities, we have identified opportunities to invest in transmission facilities upgrades which will help to mitigate the impact of congestion around our Baldwin plant. We are working with the Transmission Owner to potentially implement these upgrades. We continue to assess grid constraints impacting our other facilities to identify other opportunities to reduce congestion and improve LMPs at our Coal and newly acquired IPH facilities.

IPH. The IPH segment consists of five plants, totaling 4,062 MW. The Coffeen, Edwards, Duck Creek and Newton facilities are located in the MISO region. Joppa is located within its own control area, known as EEI. Joppa sells all of its net power into three connected control areas: MISO, TVA and LGE.

As of February 21, 2014, our IPH expected generation volumes are 78 percent hedged volumetrically for 2014 and approximately 47 percent hedged volumetrically for 2015. The IPH hedging program will continue to use our retail business, Homefield Energy, to hedge a portion of the output from our IPH facilities. The retail hedges are well correlated to our facilities due to the close proximity of the hedge and through participation in FTR markets. We also plan to use other instruments to hedge the power revenue. Future new business and recontracting of existing business will impact IPH's hedge levels in the future.

As of February 21, 2014, our expected coal requirements for IPH are 95 percent contracted and 84 percent priced for 2014. Our forecasted coal requirements for 2015 are 44 percent contracted and 22 percent priced. Our coal transportation requirements are fully contracted and priced for the next several years. We continue to explore various alternative contractual commitments and financial options to ensure stable and competitive fuel supplies and to mitigate further supply risks for near- and long-term coal supplies.

Gas. The Gas segment consists of seven plants, geographically diverse in five markets, totaling 6,121 MW.

Approximately 70 percent of our power plant capacity in the CAISO market is contracted through 2014 under tolling agreements with LSEs and a RMR agreement. A significant portion of the remaining capacity is sold as a resource adequacy product in the CAISO market.

The CAISO capacity market is bilateral in nature. The LSEs are required to procure sufficient resources for their peak load plus a fifteen percent reserve margin. The CAISO footprint currently has a capacity surplus due to a weak economy and increased participation from renewable resources. The CAISO faces challenges to ensure system reliability as well as adequate ancillary services in the future with the mandate to have 33 percent renewable resources by 2020. The combination of bilateral markets, one-off utility procurements and short-term requirements make this a larger concern than in other markets where multi-year forward requirements and more transparent markets are in place. The CAISO and CPUC recently released a joint proposal for a multi-year forward capacity market called the Joint Reliability Framework. This proposal would fill the gap between the Resource Adequacy (one-year requirement) and the LTPP (ten-year plan) to establish a multi-year forward resource adequacy requirement on LSEs, provide a CAISO administered multi-year forward capacity market, and a market-based backstop mechanism to procure reliability services (both capacity and flexibility). A flexible capacity requirement has been imposed on CPUC jurisdictional load-serving entities via the Resource Adequacy proceeding and will be mandatory for 2015. The CAISO is currently working on the rules for how the flexible capacity will be counted and how it must be offered into the CAISO markets. The CPUC and CAISO have updated their proposals and appear to have abandoned any potential solution that results in a multi-year forward centrally-administered capacity market. There is little chance that a CAISO administered multi-year forward capacity market will be considered again until 2016.

The estimated useful lives of our generation facilities consider environmental regulations currently in place. With respect to Units 6 and 7 at our Moss Landing facility, we are continuing to review the potential impact of the California Water Intake Policy. We are currently depreciating these units through 2024; however, depending on (i) a final determination of the compliance term and requirements of the California Water Intake Policy and (ii) our ability to secure energy and/or capacity contracts in the future, we could decide to reduce operations or cease to operate the units prior to 2024. The Morro Bay facility was retired on February 5, 2014; we are currently evaluating alternatives for the site including developing renewable energy shaping technologies as well as preferred renewable resources, as defined by California laws and regulations.

In New England, eight forward capacity auctions have been held since the ISO-NE transitioned to a forward capacity market in June 2010. The highest clearing price of $15/kW-month occurred in the most recent auction for the 2017-2018 market period. However, the “insufficient competition” clause in the ISO-NE tariff was triggered, resulting in existing generation receiving an administrative cap price of $2.95 per kW-month was seen for the 2013-2014 market period. Due to oversupply conditions, the seven prior annual auctions cleared at the designated floor. Changes made to the forward capacity market design removed the auction floor price and implemented a minimum offer price rule that set a floor price for new entrants based on technology type. For the eighth auction, the floor price was removed. However, the auction cleared at the high mark, with existing generation receiving the administrative cap due to significant capacity retirements in the region. ISO-NE is developing additional changes to the forward capacity market including performance incentives and a sloped demand curve which are expected to be in place f

Table of Contents

or the ninth forward capacity auction in 2015.

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

Capacity pricing for the NYISO seems to be recovering from the low point in 2011. The most recent summer and winter auctions have cleared higher than the previous auctions with summer 2013 at $4.20 per kW-month and winter 2013-2014 at $2.58 per kW-month for the rest of state market. We attribute the rebound in part 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 February 21, 2014, our Gas portfolio is 58 percent hedged volumetrically through 2014 and approximately 15 percent hedged volumetrically for 2015. As a result of the offsetting risks of our Gas and Coal segments, we are able to reduce the costs associated with hedging by executing a portion of our natural gas hedges with an internal affiliate. As discussed above, we intend to expand this in the future. We continue to manage our remaining commodity price exposure to changing fuel and power prices in accordance with our risk management policy.

SEASONALITY

Our revenues and operating income are subject to fluctuations during the year, primarily due to the impact seasonal factors have on sales volumes and the prices of power and natural gas. Power marketing operations and generating facilities have higher volatility and demand, respectively, in the summer cooling months. This trend may change over time as demand for natural gas increases in the summer months as a result of increased natural gas-fired electricity generation. Further, to the extent that climate change may affect weather patterns, this could result in more extreme weather patterns which could impact demand for our products.

CRITICAL ACCOUNTING POLICIES

Our Accounting Department is responsible for the development and application of accounting policy and control procedures. This department conducts these activities independent of any active management of our risk exposures, is independent of our business segments and reports to the Chief Financial Officer.

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments. It is possible that materially different amounts could be recorded if these estimates and judgments change or if actual results differ from these estimates and judgments. We have identified the following critical accounting policies that require a significant amount of estimation and judgment and are considered important to the portrayal of our financial position and results of operations:

- Revenue Recognition and Derivative Instruments;
- Fair Value Measurements;
- Accounting for Income Taxes; and
- Business Combinations and Fresh-Start Accounting.

Revenue Recognition and Derivative Instruments

We earn revenue from our facilities in three primary ways: (i) the sale of energy, including fuel, through both physical and financial transactions; (ii) sale of capacity; and (iii) sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load and provide emergency reserves for major changes to the balance of generation and load. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative. Please read “Derivative Instruments—Generation” below for further discussion of the accounting for these types of transactions.

Derivative Instruments—Generation. We enter into commodity contracts that meet the definition of a derivative. These contracts are often entered into to mitigate or eliminate market and financial risks associated with our generation business. These contracts include forward contracts, which commit us to sell commodities in the future; futures contracts, which are generally broker-cleared standard commitments to purchase or sell a commodity; option contracts, which convey the right to buy or sell a commodity; and swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined quantity. There are three different ways to account for these types of contracts: (i) as an accrual contract, if the criteria for the "normal purchase, normal sale" exception are met and documented; (ii) as a cash flow or fair value hedge, if the criteria are met and documented; or (iii) as a mark-to-market contract with changes in fair value recognized in current period earnings. All derivative commodity contracts that do not qualify for the "normal purchase, normal sale" exception are recorded at fair value in risk management assets and liabilities on the consolidated balance sheets with the associated changes in fair value recorded currently in earnings. Dynegy does not elect hedge accounting for any of its derivative instruments. Entities may choose whether or not to offset related assets and liabilities and report the net amounts on their consolidated balance sheet if the right of offset exists. We elect to offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement and we elected to offset the fair value of amounts recognized for the Daily Cash Settlements paid or received against the fair value of amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. As a result, our consolidated balance sheets present derivative assets and liabilities, as well as the related cash collateral paid or received, on a net basis.

Derivative Instruments—Financing Activities. We are exposed to changes in interest rate risk through our variable rate debt. In order to manage our interest rate risk, we enter into interest rate swap agreements that meet the definition of a derivative. All derivative instruments are recorded at their fair value on the consolidated balance sheet with the changes in fair value recorded to interest expense. Our interest-based derivative instruments are not designated as hedges of our variable debt.

Fair Value Measurements

Fair Value Measurements. Accounting standards define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. In estimating fair value, we use discounted cash-flow projections, recent comparable market transactions, if available, or quoted prices. We consider assumptions that third parties would make in estimating fair value, including the highest and best use of the asset. There is a significant amount of judgment involved in cash-flow estimates, including assumptions regarding market convergence, discount rates and capacity prices. The assumptions used by another party could differ significantly from our assumptions.

Our estimate of fair value reflects the impact of credit risk. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs are classified as readily observable, market corroborated or generally unobservable. 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 classify fair value balances based on the classification of the inputs used to calculate the fair value of a transaction. The inputs used to measure fair value have been placed in a hierarchy based on priority. The hierarchy gives the highest priority to unadjusted, readily observable quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are classified as follows:

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as listed equities.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using industry-standard models or other valuation methodologies, in which substantially all assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over the counter forwards, options, and swaps.
- Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to our needs. At each balance sheet date, we perform an analysis of all instruments and include in Level 3 all of those whose fair value is based on significant unobservable inputs.

Fair Value Measurements—Risk Management Activities. The determination of the fair value for each derivative contract incorporates various factors. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities. Valuation adjustments are generally based on capital market implied ratings evidence when assessing the credit standing of our counterparties and when applicable, adjusted based on management's estimates of assumptions market participants would use in determining fair value.

Assets and liabilities from risk management activities may include exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivatives, as discussed above, are generally classified as Level 1; however, some exchange-traded derivatives are valued using broker or dealer quotations or market transactions in either the listed or OTC markets. In such cases, these exchange-traded derivatives are classified within Level 2. OTC derivative trading instruments include swaps, forwards and options. In certain instances, these instruments may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Other OTC derivatives trade in less active markets with a lower availability of pricing information. In addition, complex or structured transactions, such as heat-rate call options, can introduce the need for internally-developed model inputs that might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

Table of Contents

Accounting for Income Taxes
We file a consolidated U.S. federal income tax return. We use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant differences.
As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing tax and accounting treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our consolidated balance sheet. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.
Because we operate and sell power in many different states, our effective annual state income tax rate may vary from period to period because of changes in our sales profile by state, as well as jurisdictional and legislative changes by state. As a result, changes in our estimated effective annual state income tax rate can have a significant impact on our measurement of temporary differences. We project the rates at which state tax temporary differences will reverse based upon estimates of revenues and operations in the respective jurisdictions in which we conduct business.
The guidance related to accounting for income taxes requires that a valuation allowance be established when it is more-likely-than-not that all or a portion of a deferred tax asset will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income of the appropriate character during the periods in which those temporary differences are deductible. In making this determination, management considers all available positive and negative evidence affecting specific deferred tax assets, including our past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.
We do not believe we will produce sufficient future taxable income, nor are there tax planning strategies available to realize the tax benefits from, net deferred tax assets not otherwise realized by reversing temporary differences. Therefore, a valuation allowance was placed against our net deferred tax assets as of December 31, 2013 and 2012. Any change in the valuation allowance would impact our income tax benefit (expense) and net income (loss) in the period in which the change occurs.
Accounting for uncertainty in income taxes requires that we determine whether it is more-likely-than-not that a tax position we have taken will be sustained upon examination. If we determine that it is more likely than not that the position will be sustained, we recognize the largest amount of the benefit that is greater than 50 percent likely of being realized upon settlement. There is a significant amount of judgment involved in assessing the likelihood that a tax position will be sustained upon examination and in determining the amount of the benefit that will ultimately be realized.
We recognize accrued interest expense and penalties related to unrecognized tax benefits as income tax expense. Please read Note 14—Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions and changes in our valuation allowance.
Business Combinations and Fresh-Start Accounting
U.S. GAAP requires that the purchase price for an acquisition, such as our AER Acquisition, be assigned and allocated to the individual assets and liabilities based upon their fair value (or in the case of fresh-start accounting, the reorganization value as approved by the Bankruptcy Court). Generally, the amount recorded in the financial statements for an acquisition is the purchase price (value of the consideration paid), but a purchase price that exceeds the fair value of the assets acquired will result in the recognition of goodwill. In addition to the potential for the recognition of goodwill, differing fair values will impact the allocation of the purchase price to the individual assets and liabilities and can impact the gross amount and classification of assets and liabilities recorded on our consolidated balance sheets and can impact the timing and the amount of depreciation and amortization expense recorded in any given period. We utilize our best effort to make our determinations and review all information available including estimated future cash flows and prices of similar assets when making our best estimate. We also may hire independent appraisers to help us make this determination as we deem appropriate under the circumstances.

There is a significant amount of judgment in determining the fair value of the acquisitions and in allocating value to individual assets and liabilities. Had different assumptions been used, our investment value in the entities acquired could have been significantly higher or lower with a corresponding increase or reduction in our asset and liability values. Refer to Note 3—Merger and Acquisitions for further discussion of the AER Acquisition.

On the Plan Effective Date, we applied fresh-start accounting in accordance with guidance under the applicable reorganization accounting rules. These rules require that we allocate the reorganization value of the Successor to its assets and

Table of Contents

liabilities based upon their estimated fair values determined in conformity with the guidance for the acquisition method of accounting for business combinations.

We recorded the fair value of some assets and liabilities at cost, which was an appropriate measure of fair value (i.e. cash, restricted cash, accounts payable). Other assets and liabilities were adjusted to fair value based on then-current market prices (i.e. inventory). The fair value of our outstanding long-term debt was fair valued based upon the trading price of the debt on the Plan Effective Date.

There is a significant amount of judgment in determining the reorganization value and in allocating value to individual assets and liabilities. Had different assumptions been used, our reorganization value could have been significantly higher or lower, which could have resulted in goodwill or a reduction in our asset values. Refer to Note 21—Emergence from Bankruptcy and Fresh-Start Accounting—Accounting Impact of Emergence for further discussion.

RECENT ACCOUNTING PRONOUNCEMENTS

Please read Note 2—Summary of Significant Accounting Policies for further discussion of accounting principles adopted and accounting principles not yet adopted.

RISK MANAGEMENT DISCLOSURES

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

(amounts in millions)	
Fair value of portfolio at December 31, 2012	$(50)
Risk management losses recognized through the statement of operations in the period, net	(46)
Contracts realized or otherwise settled during the period	8
AER Acquisition	30
Change in collateral/margin netting	(4)
Fair value of portfolio at December 31, 2013	$(62)

The net risk management liability of $62 million is the aggregate of the following line items on our 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 December 31, 2013, based on our valuation methodology:

Net Fair Value of Risk Management Portfolio

(amounts in millions)	Total	2014	2015	2016	2017	2018	Thereafter
Market quotations (1) (2)	$(76)	$(47)	$(17)	$(11)	$(6)	$1	$4
Prices based on models (2)	10	2	6	2	—	—	—
Total (3)	$(66)	$(45)	$(11)	$(9)	$(6)	$1	$4

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

(2) The market quotations category represents our transactions classified as Level 1 and Level 2. The prices based on models category represents transactions classified as Level 3. Please read Note 4—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

(3) Excludes $4 million of broker margin that has been netted against Risk management liabilities on our consolidated balance sheet. Please read Note 4—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

Table of Contents

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to commodity price variability related to our power generation business. In order to manage these commodity price risks, we routinely utilize various fixed-price forward purchase and sales contracts, futures and option contracts traded on the New York Mercantile Exchange or the Intercontinental Exchange and swaps and options traded in the OTC financial markets to:

- manage and hedge our fixed-price purchase and sales commitments;
- reduce our exposure to the volatility of cash market prices; and
- hedge our fuel requirements for our generating facilities.

The potential for changes in the market value of our commodity and interest rate portfolios is referred to as "market risk." A description of each market risk category is set forth below:

- commodity price risks result from exposures to changes in spot prices, forward prices and volatilities in commodities, such as electricity, natural gas, coal, fuel oil, emissions and other similar products; and
- interest rate risks primarily result from exposures to changes in the level, slope and curvature of the yield curve and the volatility of interest rates.

In the past, we have attempted to manage these market risks through diversification, controlling position sizes and executing hedging strategies. The ability to manage an exposure may, however, be limited by adverse changes in market liquidity, our credit capacity or other factors.

VaR. The modeling of the risk characteristics of our mark-to-market portfolio involves a number of assumptions and approximations. We estimate VaR using a Monte Carlo simulation-based methodology. Inputs for the VaR calculation are prices, positions, instrument valuations and the variance-covariance matrix. VaR does not account for liquidity risk or the potential that adverse market conditions may prevent liquidation of existing market positions in a timely fashion. While management believes that these assumptions and approximations are reasonable, there is no uniform industry methodology for estimating VaR, and different assumptions and/or approximations could produce materially different VaR estimates.

We use historical data to estimate our VaR and, to reflect current asset and liability volatilities better, this historical data is weighted to give greater importance to more recent observations. Given our reliance on historical data, VaR is effective in estimating risk exposures in markets in which there are not sudden fundamental changes or abnormal shifts in market conditions. An inherent limitation of VaR is that past changes in market risk factors, even when weighted toward more recent observations, may not produce accurate predictions of future market risk. VaR should be evaluated in light of this and the methodology's other limitations.

VaR represents the potential loss in value of our mark-to-market portfolio due to adverse market movements over a defined time horizon within a specified confidence level. For the VaR numbers reported below, a one-day time horizon and a 95 percent confidence level were used. This means that there is a one in 20 chance that the daily portfolio value will drop in value by an amount larger than the reported VaR. Thus, an adverse change in portfolio value greater than the expected change in portfolio value on a single trading day would be anticipated to occur, on average, about once a month. Gains or losses on a single day can exceed reported VaR by significant amounts. Gains or losses can also accumulate over a longer time horizon such as a number of consecutive trading days.

In addition, we have provided our VaR using a one-day time horizon with a 99 percent confidence level. The purpose of this disclosure is to provide an indication of earnings volatility using a higher confidence level. Under this presentation, there is a one in 100 statistical chance that the daily portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR. We have also disclosed a two-year comparison of daily VaR in order to provide context for the one-day amounts.

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.

The increase in the December 31, 2013 one day VaR was primarily due to increased spread volatility on gas asset hedges compared to December 31, 2012.

Table of Contents

Daily and Average VaR for Risk-Management Portfolios

(amounts in millions)	December 31, 2013	December 31, 2012
One day VaR—95 percent confidence level	$7	$2
One day VaR—99 percent confidence level	$10	$3
Average VaR for the year-to-date period—95 percent confidence level	$4	$4

Credit Risk. Credit risk represents the loss that we would incur if a counterparty fails to perform pursuant to the terms of its contractual obligations. To reduce our credit exposure, we execute agreements that permit us to offset receivables, payables and mark-to-market exposure. We attempt to reduce credit risk further with certain counterparties by obtaining third-party guarantees or collateral as well as the right of termination in the event of default.

Our Credit Department, based on guidelines approved by the Board of Directors, establishes our counterparty credit limits. Our industry typically operates under negotiated credit lines for physical delivery and financial contracts. Our credit risk system provides current credit exposure of wholesale counterparties on a daily basis and outstanding receivable size and aging information of retail customers on a weekly basis.

The following table represents our credit exposure at December 31, 2013 associated with the wholesale 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	$8	$—	$8
Oil and gas producers	1	—	1
Utility and power generators	20	—	20
Commercial/industrial/end users	1	—	1
Other	—	—	—
Total	$30	$—	$30

Interest Rate Risk

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

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

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

(1) The calculation period for $250 million of the interest rate swaps began June 30, 2013, and the calculation period for the remaining $546 million began October 31, 2013.

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

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and financial statement schedules are set forth at pages F-1 through F-72 inclusive, found at the end of this annual report, and are incorporated herein by reference.

Table of Contents

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. 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 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 (the "Exchange Act")). 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 December 31, 2013.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of our company are being made only in accordance with authorizations of our management and directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2013. In making this assessment, we used the criteria set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based on the results of this assessment and on those criteria, we concluded that our internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

Changes in Internal Controls Over Financial Reporting

There were no changes in our internal controls over financial reporting that materially affected or are reasonably likely to materially affect our internal controls over financial reporting during the quarter ended December 31, 2013.

Item 9B. Other Information

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers. We intend to include the information with respect to our executive officers required by this Item 10 in our definitive proxy statement for our 2014 annual meeting of stockholders under the heading "Executive Officers," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2013. However, if such proxy statement is not filed within such 120-day period, information with respect to Executive Officers will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Code of Ethics. We have adopted a Code of Ethics within the meaning of Item 406(b) of Regulation S-K. This Code of Ethics applies to our Chief Executive Officer, Chief Financial Officer, Controller and other persons performing similar functions designated by the Chief Financial Officer, and is filed as an exhibit to this Form 10-K.

Other Information. We intend to include the other information required by this Item 10 in our definitive proxy statement for our 2014 annual meeting of stockholders under the headings "Proposal 1—Election of Directors" and "Compliance with Section 16(a) of the Exchange Act," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2013. However, if such proxy statement is not filed within such 120-day period, information with respect to Other Information will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 11. Executive Compensation

We intend to include information with respect to executive compensation in our definitive proxy statement for our 2014 annual meeting of stockholders under the heading "Executive Compensation," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2013. However, if such proxy statement is not filed within such 120-day period, information with respect to executive compensation will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

We intend to include information regarding ownership of our outstanding securities in our definitive proxy statement for our 2014 annual meeting of stockholders under the heading "Security Ownership of Certain Beneficial Owners and Management" and "Securities Authorized for Issuance Under Equity Compensation Plan," respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2013. However, if such proxy statement is not filed within such 120-day period, information with respect to beneficial ownership will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth certain information as of December 31, 2013 as it relates to our equity compensation plans for our common stock.

Plan Category	Number of securities to be issued upon exercise of outstanding options and rights (a)	Weighted-average exercise price of outstanding options and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders (1)	1,868,728	$21.29	4,013,008
Equity compensation plans not approved by security holders	—	—	—
Total	1,868,728	$21.29	4,013,008

(1) The plan that is approved by our security holders is the 2012 Long Term Incentive Plan. Please read Note 17—Capital Stock—Stock Award Plans for further discussion.

Item 13. Certain Relationships and Related Transactions, and Director Independence

We intend to include the information regarding related party transactions and Director independence in our definitive proxy statement for our 2014 annual meeting of stockholders under the headings “Transactions with Related Persons, Promoters and Certain Control Persons,” and “Corporate Governance,” respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2013. However, if such proxy statement is not filed within such 120-day period, information with respect to certain relationships will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

Item 14. Principal Accountant Fees and Services

We intend to include information regarding principal accountant fees and services in our definitive proxy statement for our 2014 annual meeting of stockholders under the heading “Independent Registered Public Auditors—Principal Accountant Fees and Services,” which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2013. However, if such proxy statement is not filed within such 120-day period, information with respect to the principal accountant fees and services will be filed as part of an amendment to this Form 10-K not later than the end of the 120-day period.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents, which we have filed with the SEC pursuant to the Securities Exchange Act of 1934, as amended, are by this reference incorporated in and made a part of this report:

1. Financial Statements—Our consolidated financial statements are incorporated under Item 8. of this report.
2. Financial Statement Schedules—Financial Statement Schedules are incorporated under Item 8. of this report.
3. Exhibits—The following instruments and documents are included as exhibits to this report.

Exhibit Number	Description
2.1	Confirmation Order for Dynegy Inc. and Dynegy Holdings, LLC, as entered by the Bankruptcy Court on September 10, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. and Dynegy Holdings, LLC filed on September 13, 2012, File No. 001-33443).
2.2	Agreement and Plan of Merger between Dynegy Inc. and Dynegy Holdings, LLC, dated September 28, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 2, 2012, File No. 001-33443).
*2.3	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).
*2.4	Letter Agreement, dated December 2, 2013, between Ameren Corporation and Illinois Power Holdings, LLC, amending the Transaction Agreement, dated as of March 14, 2013 (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K of Dynegy Inc. filed on December 4, 2013 File No. 001-33443).
2.5	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).
3.1	Dynegy Inc. Third Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
3.2	Dynegy Inc. Fifth Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 27, 2014, File No. 001-33443).
4.1	Registration Rights Agreement, dated October 1, 2012, by and among the Company and the investors party thereto (Common Stock) (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
4.2	Indenture, dated May 20, 2013, among Dynegy Inc., the Guarantors and Wilmington Trust, National Association as Trustee (5.875% Senior Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 21, 2013 File No. 001-33443).
***4.3	First Supplemental Indenture dated as of December 5, 2013 to the Indenture, dated May 20, 2013, among Dynegy Inc., the Guarantors and Wilmington Trust, National Association as Trustee.
4.4	Registration Rights Agreement, dated May 20, 2013, among Dynegy Inc., the Guarantors, Morgan Stanley and Credit Suisse (related to 5.875% Senior Notes) (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on May 21, 2013 File No. 001-33443).
4.5	Indenture dated as of November 1, 2000, from Ameren Energy Generating Company to The Bank of New York Mellon Trust Company, N.A., as successor trustee (Genco Indenture)

	(incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-4 Filed March 6, 2001, File No. 333-56594).
4.6	Third Supplemental Indenture dated as of June 1, 2002, to Genco Indenture, relating to Genco's 7.95% Senior Notes, Series E due 2032 (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 333-56594).
4.7	Fourth Supplemental Indenture dated as of January 15, 2003, to Genco Indenture, relating to Genco 7.95% Senior Notes, Series F due 2032 (incorporated by reference to Exhibit 4.5 to the Annual Report on Form 10-K for the ended December 31, 2002, File No. 333-56594

4.8	Fifth Supplemental Indenture dated as of April 1, 2008, to Genco Indenture, relating to Genco 7.00% Senior Notes, Series G due 2018 (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Ameren Energy Generating Company filed on April 9, 2008 File No. 333-56594
4.9	Sixth Supplemental Indenture, dated as of July 7, 2008, to Genco Indenture, relating to Genco 7.00% Senior Notes, Series H due 2018 (incorporated by reference to Exhibit 4.55 to the Registration Statement on Form S-3 Filed November 17, 2008, File No. 333-56594).
4.10	Seventh Supplemental Indenture, dated as of November 1, 2009, to Genco Indenture, relating to Genco 6.30% Senior Notes, Series I due 2020 (incorporated by reference to Exhibit 4.8 to the Current Report on Form 8-K of Ameren Energy Generating Company filed on November 17, 2009 File No. 333-56594).
4.11	Registration Rights Agreement, dated June 6, 2002 among Ameren Energy Generating Company and the Initial Purchasers relating to the Ameren Energy Generating Company’s 7.95% Senior Notes, Series E due 2032 (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 333-56594).
4.12	Registration Rights Agreement, dated April 9, 2008 among Ameren Energy Generating Company and the Initial Purchasers relating to the Ameren Energy Generating Company’s 7.00% Senior Notes, Series G due 2018 (incorporated by reference to Exhibit 4.8 to the Registration Statement on Form S-4 Filed May 19, 2008, File No. 333-56594).
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	Dynegy Inc. Executive Severance Pay Plan, as amended and restated effective as of January 1, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 4, 2008, File No. 001-33443).††
10.3	First Amendment to the Dynegy Inc. Executive Severance Pay Plan effective as of January 1, 2010 (incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2009 of Dynegy Inc, File No. 1-15659).††
10.4	Second Amendment to the Dynegy Inc. Executive Severance Pay Plan, dated as of September 20, 2010. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2010 of Dynegy Inc, File No. 1-15659).††
10.5	Third Amendment to the Dynegy Inc. Executive Severance Pay Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 22, 2011, File No. 1-33443).††
10.6	Fourth Amendment to the Dynegy Inc. Executive Severance Pay Plan, dated as of August 8, 2011(incorporated by reference to Exhibit 10. 1 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.7	Dynegy Inc. Executive Change in Control Severance Pay Plan effective April 3, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 8, 2008, File No. 001-33443).††
10.8	First Amendment to the Dynegy Inc. Executive Change In Control Severance Pay Plan, dated as of September 22, 2010 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2010 of Dynegy Inc, File No. 1-15659).††
10.9	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). ††
10.10	Dynegy Inc. Restoration 401(k) Savings Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).††

10.11	First Amendment to the Dynegy Inc. Restoration 401(k) Savings Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).††
10.12	Second Amendment to Dynegy Inc. Restoration 401(k) Savings Plan, effective January 1, 2012 (incorporated by reference to Exhibit 10.23 to the Annual Report on Form 10-K of Dynegy Inc. for the year ended December 31, 2011, File No. 1-33443).††
10.13	Dynegy Inc. Restoration Pension Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).††

10.14	First Amendment to the Dynegy Inc. Restoration Pension Plan, effective June 1, 2008 (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q of Dynegy Inc. filed on August 7, 2008, File No. 001-33443).††
10.15	Second Amendment to the Dynegy Inc. Restoration Pension Plan, executed on July 2, 2010 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Dynegy Inc. and Dynegy Holdings Inc. filed on August 6, 2010, File No. 000-29311).††
10.16	Third Amendment to Dynegy Inc. Restoration Pension Plan, effective January 1, 2012 (incorporated by reference to Exhibit 10.27 to the Annual Report on Form 10-K of Dynegy Inc. for the year ended December 31, 2011, File No. 1-33443).††
10.17	Dynegy Inc. 2009 Phantom Stock Plan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 10, 2009, File No. 001-33443).††
10.18	First Amendment to the Dynegy Inc. 2009 Phantom Stock Plan, dated as of July 8, 2011(incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.19	Dynegy Inc. Deferred Compensation Plan for Certain Directors, as amended and restated, effective January 1, 2008 (incorporated by reference to Exhibit 10.55 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443).††
10.20	Trust under Dynegy Inc. Deferred Compensation Plan for Certain Directors, effective January 1, 2009 (incorporated by reference to Exhibit 10.56 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2009, filed on February 26, 2009, File No. 001-33443).††
10.21	Dynegy Inc. Incentive Compensation Plan, as amended and restated effective May 21, 2010 (incorporated by reference to Exhibit 10.34 to the Annual Report on Form 10-K for the Fiscal Year ended December 31, 2010, File No. 001-33443)††
10.22	2012 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).††
10.23	Assignment Agreement by and between Dynegy Inc. and Dynegy Operating Company, dated July 5, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. on July 10, 2012, File No. 001-33443).††
10.24	Employment Agreement between Dynegy Inc. and Robert Flexon dated June 22, 2011(incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.25	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). ††
10.26	Employment Agreement between Dynegy Inc. and Clint C. Freeland dated June 23, 2011(incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.27	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). ††
10.28	Employment Agreement between Dynegy Inc. and Carolyn J. Burke dated July 5, 2011(incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.29	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). ††

10.30	Employment Agreement between Dynegy Inc. and Catherine Callaway dated September 16, 2011 (incorporated by reference to Exhibit 10. 2 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2011 of Dynegy Inc., File No. 1- 33443).††
10.31	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). ††
10.32	Employment Agreement by and among Dynegy Operating Company, Dynegy Inc. and Henry D. Jones (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 12, 2013, File No. 001-33443). ††
10.33	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). ††

10.34	Form Award Agreement for 2012 Long Term Incentive Program Award-Cash (CEO) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on January 9, 2012 File No. 001-33443).††
10.35	Form Award Agreement for 2012 Long Term Incentive Program Award-Cash (EVP) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on January 9, 2012 File No. 001-33443).††
10.36	Form of Non-Qualified Stock Option Award Agreement (2012 Awards) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443). ††
10.37	Form of Non-Qualified Stock Option Award Agreement (2013 Awards) (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). ††
10.38	Form of Stock Unit Award Agreement - Officers (2012 Awards) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443). ††
10.39	Form of Stock Unit Award Agreement - Officers (2013 Awards) (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). ††
10.40	Form of Stock Unit Award Agreement - Directors (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. on November 2, 2012, File No. 001-33443). ††
10.41	Form of Performance Award Agreement (2013 Awards) (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). ††
10.42	Form of Phantom Stock Unit Award Agreement - MD & Above Version (2012 LTIP Awards) (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2012 of Dynegy Inc., File No. 1- 33443). ††
10.43	Form of Phantom Stock Unit Award Agreement - MD & Above Version (2012 Replacement Shares) (incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2012 of Dynegy Inc., File No. 1- 33443). ††
10.44	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).
10.45	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).
10.46	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).
10.47	

	Purchase Agreement, dated May 15, 2013, among Dynegy Inc., the Guarantors, Morgan Stanley and Credit Suisse (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 21, 2013 File No. 001-33443).
10.48	Revolving Promissory Note by and between Dynegy Inc., as Lender, and Illinois Power Resources, LLC (formerly New Ameren Energy Resources, LLC), as Borrower (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on December 4, 2013 File No. 001-33443).
10.49	Guaranty by Ameren Energy Generating Company in favor of Ameren Corporation, dated December 2, 2013 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Illinois Power Generating Company filed on December 5, 2013 File No. 333-56594).
****10.50	Warrant Agreement, dated October 1, 2012, by and among Dynegy Inc., Computershare Inc. and Computershare Trust Company, N.A., as warrant agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 4, 2012, File No. 001-33443).
10.51	Letter of Credit and Reimbursement Agreement, dated as of January 29, 2014 between Illinois Power Marketing Company and Union Bank, N.A.(incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. and Illinois Power Generating Company filed on February 4, 2014, File No. 001-33443).
***12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
***14.1	Dynegy Inc. Code of Ethics for Senior Financial Professionals, as amended on July 23, 2013.

77

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

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

** XBRL information is furnished and not filed for purposes of Section 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934, and is not subject to liability under those sections, is not part of any registration statement or prospectus to which it relates and is not incorporated or deemed to be incorporated by reference into any registration statement, prospectus or other document.

*** Filed herewith.

**** Pursuant to a request for confidential treatment, portions of this Exhibit have been redacted and filed separately with the SEC as required by Rule 24b-2 under the Securities Exchange Act of 1934, as amended.

† 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.

†† Management contract or compensation plan.

SIGNATURES

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, the thereunto duly authorized.

		DYNEGY INC.	
			/s/ ROBERT C. FLEXON
Date:	February 27, 2014	By:	Robert C. Flexon
			President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

/s/ ROBERT C. FLEXON Robert C. Flexon	President and Chief Executive Officer & Director (Principal Executive Officer)	February 27, 2014
/s/ CLINT C. FREELAND Clint C. Freeland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2014
/s/ J. CLINTON WALDEN J. Clinton Walden	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2014
/s/ PAT WOOD III Pat Wood III	Chairman of the Board	February 27, 2014
/s/ HILARY E. ACKERMANN Hilary E. Ackermann	Director	February 27, 2014
/s/ PAUL M. BARBAS Paul M. Barbas	Director	February 27, 2014
/s/ RICHARD LEE KUERSTEINER Richard Lee Kuersteiner	Director	February 27, 2014
/s/ JEFFREY S. STEIN Jeffrey S. Stein	Director	February 27, 2014
/s/ JOHN R. SULT John R. Sult	Director	February 27, 2014

DYNEGY INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.:

We have audited Dynegy Inc.’s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission “(1992 framework)” (the COSO criteria). Dynegy Inc.’s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Dynegy Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2013 consolidated financial statements of Dynegy Inc. and our report dated February 27, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2014

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Dynegy Inc.:

We have audited the accompanying consolidated balance sheets of Dynegy Inc. (the Company) as of December 31, 2013 and 2012 (Successor), and the related consolidated statements of operations, comprehensive loss, changes in equity and cash flows for the year ended December 31, 2013 (Successor), the period from October 2, 2012 through December 31, 2012 (Successor), the period from January 1, 2012 through October 1, 2012 (Predecessor), and for the year ended December 31, 2011 (Predecessor). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Dynegy Inc. at December 31, 2013 and 2012 (Successor), and the consolidated results of its operations and its cash flows for the year ended December 31, 2013 (Successor), the period from October 2, 2012 through December 31, 2012 (Successor), the period from January 1, 2012 through October 1, 2012 (Predecessor), and for the year ended December 31, 2011 (Predecessor), in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 2 and 21 to the consolidated financial statements, on September 10, 2012, the Bankruptcy Court entered an order confirming the Joint Chapter 11 Plan of Reorganization, which became effective on October, 1, 2012. Accordingly, the accompanying consolidated financial statements as of and for the period from October 2, 2012 through December 31, 2012 have been prepared in conformity with Accounting Standards Codification 852-10, Reorganizations, applying fresh-start accounting and thus assets, liabilities and a capital structure having carrying amounts not comparable with prior periods as described in Notes 2 and 21.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Dynegy Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission "(1992 framework)" and our report dated February 27, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 27, 2014

F-3

Item 1—FINANCIAL STATEMENTS

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

	December 31, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	$843	$348
Restricted cash	—	98
Accounts receivable, net	420	109
Inventory	181	101
Assets from risk management activities	25	17
Intangible assets	108	271
Prepayments and other current assets	108	99
Total Current Assets	1,685	1,043
Property, Plant and Equipment	3,527	3,064
Accumulated depreciation	(212)	(42)
Property, Plant and Equipment, Net	3,315	3,022
Other Assets		
Restricted cash	—	237
Assets from risk management activities	11	—
Intangible assets	68	71
Deferred income taxes	100	95
Deferred financing costs	28	—
Other long-term assets	84	67
Total Assets	$5,291	$4,535

See the notes to consolidated financial statements.

Table of Contents

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

	December 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$329	$113
Accrued interest	13	—
Deferred income taxes	100	95
Intangible liabilities	62	17
Accrued liabilities and other current liabilities	139	68
Liabilities from risk management activities	65	25
Current portion of long-term debt	13	29
Total Current Liabilities	721	347
Long-term debt	1,979	1,386
Other Liabilities		
Liabilities from risk management activities	33	42
Asset retirement obligations	173	75
Other long-term liabilities	178	182
Total Liabilities	3,084	2,032
Commitments and Contingencies (Note 16)		
Stockholders' Equity		
Common stock, $0.01 par value, 420,000,000 shares authorized at December 31, 2013 and 2012; 100,202,036 shares and 99,999,196 shares issued and outstanding at December 31, 2013 and 2012	1	1
Additional paid-in capital	2,614	2,598
Accumulated other comprehensive income, net of tax	58	11
Accumulated deficit	(463)	(107)
Total Dynegy Stockholders' Equity	2,210	2,503
Noncontrolling interest	(3)	—
Total Equity	2,207	2,503
Total Liabilities and Equity	$5,291	$4,535

See the notes to consolidated financial statements.

Table of Contents

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

	Successor		Predecessor	
	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012	Year Ended December 31, 2011
Revenues	$1,466	$312	$981	$1,333
Cost of sales	(1,145)	(268)	(662)	(866)
Gross margin, exclusive of depreciation shown separately below	321	44	319	467
Operating and maintenance expense, exclusive of depreciation shown separately below	(308)	(81)	(148)	(254)
Depreciation expense	(216)	(45)	(110)	(295)
Other charges	—	—	—	(5)
Gain on sale of assets, net	2	—	—	—
General and administrative expense	(97)	(22)	(56)	(102)
Acquisition and integration costs	(20)	—	—	—
Operating income (loss)	(318)	(104)	5	(189)
Bankruptcy reorganization items, net	(1)	(3)	1,037	(52)
Earnings from unconsolidated investments	2	2	—	—
Interest expense	(97)	(16)	(120)	(348)
Loss on extinguishment of debt	(11)	—	—	(21)
Impairment of Undertaking receivable, affiliate	—	—	(832)	—
Other income and expense, net	8	8	31	35
Income (loss) from continuing operations before income taxes	(417)	(113)	121	(575)
Income tax benefit (Note 14)	58	—	9	144
Income (loss) from continuing operations	(359)	(113)	130	(431)
Income (loss) from discontinued operations, net of tax (Note 23)	3	6	(162)	(509)
Net loss	(356)	(107)	(32)	(940)
Less: Net income (loss) attributable to noncontrolling interests	—	—	—	—
Net loss attributable to Dynegy Inc.	$(356)	$(107)	$(32)	$(940)
Loss Per Share (Note 15):				
Basic loss per share attributable to Dynegy Inc.:				
Loss from continuing operations	$(3.59)	$(1.13)	N/A	N/A
Income from discontinued operations	0.03	0.06	N/A	N/A
Basic loss per share attributable to Dynegy Inc.	$(3.56)	$(1.07)	N/A	N/A
Diluted loss per share attributable to Dynegy Inc.:				
Loss from continuing operations	$(3.59)	$(1.13)	N/A	N/A
Income from discontinued operations	0.03	0.06	N/A	N/A
Diluted loss per share attributable to Dynegy Inc.	$(3.56)	$(1.07)	N/A	N/A

Basic shares outstanding	100	100	N/A	N/A
Diluted shares outstanding	100	100	N/A	N/A

See the notes to consolidated financial statements.

Table of Contents

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

	Successor		Predecessor	
	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012	Year Ended December 31, 2011
Net loss	$(356)	$(107)	$(32)	$(940)
Other comprehensive income (loss) before reclassifications:				
Actuarial gain and plan amendments (net of tax expense of $31, zero, zero and zero, respectively)	57	11	—	—
Amounts reclassified from accumulated other comprehensive income (loss):				
Reclassification of mark-to-market gains to earnings on interest rate swaps designated as cash flow hedges, net (net of tax benefit of zero, zero, zero and $3, respectively)	—	—	—	(2)
Reclassification of curtailment gain included in net loss, net of tax	(7)	—	—	—
Amortization of unrecognized prior service cost and actuarial gain (loss) (net of tax expense of zero, zero, zero and $(2), respectively)	(2)	—	(1)	4
Other comprehensive income (loss), net of tax	48	11	(1)	2
Comprehensive loss	(308)	(96)	(33)	(938)
Less: Comprehensive income (loss) attributable to noncontrolling interests	1	—	—	—
Total comprehensive loss attributable to Dynegy Inc.	$(309)	$(96)	$(33)	$(938)

See the notes to consolidated financial statements.

Table of Contents

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

	Successor		Predecessor	
	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012	Year Ended December 31, 2011
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net loss	$(356)	$(107)	$(32)	$(940)
Adjustments to reconcile net loss to net cash flows from operating activities:				
Depreciation expense	216	45	110	288
Loss on extinguishment of debt	11	—	—	21
Non-cash interest expense (benefit)	2	(19)	8	20
Amortization of intangibles	251	60	79	39
Bankruptcy reorganization items, net	—	—	(947)	663
Impairment and other charges	—	—	832	2
Risk-management activities	38	(46)	(82)	199
Gain on sale of assets, net	(2)	—	—	(1)
Deferred income taxes	(56)	—	(9)	(315)
Change in value of common stock warrants	1	(8)	—	—
Other	14	(3)	(10)	7
Changes in working capital:				
Accounts receivable, net	(75)	—	9	81
Inventory	24	1	7	12
Prepayments and other current assets	48	49	(43)	(48)
Accounts payable and accrued liabilities	71	(3)	38	130
Affiliate transactions	—	—	19	(73)
Changes in non-current assets	(12)	(10)	(16)	(87)
Changes in non-current liabilities	—	(3)	—	1
Net cash provided by (used in) operating activities	175	(44)	(37)	(1)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Capital expenditures	(98)	(46)	(63)	(196)
Proceeds from asset sales, net	3	—	—	—
Maturities of short-term investments	—	—	—	419
Purchases of short-term investments	—	—	—	(244)
Decrease in restricted cash	335	311	88	222
Acquisitions, net of cash acquired/divestitures	234	—	256	(441)
Deconsolidation of DNE Debtor Entities	—	—	(22)	—
Payments received for Undertaking, receivable affiliate	—	—	16	—
Other investing	—	—	3	11
Net cash provided by (used in) investing activities	474	265	278	(229)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Payment to unsecured creditors	—	—	(200)	—
Proceeds from long-term borrowings, net of financing costs	1,768	—	—	2,022
	(1,917)	(328)	(11)	(1,647)

Repayments of borrowings, including debt extinguishment costs				
Interest rate swap settlement payments	(5)	—	—	—
Recapitalization of Legacy Dynegy	—	—	27	—
Net cash provided by (used in) financing activities	(154)	(328)	(184)	375
Net increase (decrease) in cash and cash equivalents	495	(107)	57	145
Cash and cash equivalents, beginning of period	348	455	398	253
Cash and cash equivalents, end of period	$843	$348	$455	$398

See the notes to consolidated financial statements.

Table of Contents

DYNEGY INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(in millions)

	Common Stock	Additional Paid-In Capital	Member's Contribution	Affiliate Receivable	AOCI (Loss)	Accumulated Deficit	Total Controlling Interests	Noncontrolling Interests	Total
December 31, 2010 (Predecessor)	$—	$—	$ 5,135	$ (814)	$ (53)	$ (1,549)	$ 2,719	$ —	$ 2,719
Net loss	—	—	—	—	—	(940)	(940)	—	(940)
Other comprehensive income, net of tax	—	—	—	—	2	—	2	—	2
Affiliate activity (Note 13)	—	—	—	20	—	—	20	—	20
DMG Transfer	—	—	—	(52)	52	(1,769)	(1,769)	—	(1,769)
December 31, 2011 (Predecessor)	—	—	5,135	(846)	1	(4,258)	32	—	32
Net loss	—	—	—	—	—	(32)	(32)	—	(32)
Other comprehensive loss, net of tax	—	—	—	—	(1)	—	(1)	—	(1)
Affiliate activity (Note 13)	—	—	—	846	—	(846)	—	—	—
DMG Acquisition	—	—	—	—	(24)	—	(24)	—	(24)
Merger	1	5,166	(5,135)	—	—	—	32	—	32
October 1, 2012 (Predecessor)	1	5,166	—	—	(24)	(5,136)	7	—	7
Fresh-start adjustments:									
Elimination of Predecessor equity	(1)	(5,166)	—	—	24	5,136	(7)	—	(7)
Issuance of new equity interests	1	2,597	—	—	—	—	2,598	—	2,598
October 2, 2012 (Successor)	1	2,597	—	—	—	—	2,598	—	2,598
Net loss	—	—	—	—	—	(107)	(107)	—	(107)
Share-based compensation	—	1	—	—	—	—	1	—	1

expense									
Other comprehensive income, net of tax	—	—	—	—	11	—	11	—	11
December 31, 2012 (Successor)	1	2,598	—	—	11	(107)	2,503	—	2,503
Net loss	—	—	—	—	—	(356)	(356)	—	(356)
Other comprehensive income, net of tax	—	—	—	—	47	—	47	1	48

F-9

Table of Contents

Share-based compensation expense	—	14	—	—	—	—		14	—		14
Options exercised	—	2	—	—	—	—		2	—		2
AER Acquisition	—	—	—	—	—	—		—	(4	)	(4)
December 31, 2013 (Successor)	$1	$2,614	$—	$—	$58	$(463	)	$2,210	$(3	)	$2,207

See the notes to consolidated financial statements.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Operations

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. Unless the context indicates otherwise, throughout this report, the terms "Dynegy," "the Company," "we," "us," "our" and "ours" are used 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. We report the results of our power generation business as three segments in our consolidated financial statements: (i) the Coal segment ("Coal"), (ii) the IPH segment ("IPH") and (iii) the Gas segment ("Gas"). Our consolidated financial results also reflect corporate-level expenses such as general and administrative expense, interest expense and income tax benefit (expense).

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

Note 2—Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation. Between November 7, 2011 and September 30, 2012, we operated as a debtor-in-possession under the supervision of the Bankruptcy Court. For financial reporting purposes, close of business on October 1, 2012, represents the date of our emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

"Predecessor"	The Company, pre-emergence from bankruptcy
"2012 Predecessor Period"	The Company's operations, January 1, 2012 — October 1, 2012
"Successor"	The Company, post-emergence from bankruptcy
"2012 Successor Period"	The Company's operations, October 2, 2012 — December 31, 2012

The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries. Intercompany accounts and transactions have been eliminated. Accounting policies for all of our operations are in accordance with accounting principles generally accepted in the United States of America.

Unconsolidated Investments. We use the equity method of accounting for investments in affiliates over which we exercise significant influence. We use the cost method of accounting where we do not exercise significant influence. Our share of net income (loss) from these affiliates is reflected in the consolidated statements of operations as Earnings from unconsolidated investments. All investments in unconsolidated affiliates are periodically assessed for other-than-temporary declines in value, with write-downs recognized in Earnings from unconsolidated investments in the consolidated statements of operations.

Please read Note 23—Dispositions and Discontinued Operations for a discussion of discontinued operations related to the deconsolidation of DNE.

Noncontrolling Interest. Noncontrolling interest is comprised of the 20 percent of Electric Energy, Inc. ("EEI") which we do not own. This noncontrolling interest is classified as a component of equity separate from our equity in the consolidated balance sheets. Please refer to Note 3—Merger and Acquisitions for further details.

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. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements.

Estimates and judgments are used in, among other things, (i) developing fair value assumptions, including estimates of future cash flows and discount rates, (ii) analyzing tangible and intangible assets for possible impairment, (iii) estimating the useful lives of our assets and AROs, (iv) assessing future tax exposure and the realization of deferred tax assets, (v) determining amounts to accrue for contingencies, guarantees and, indemnifications and (vi) estimating

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

various factors used to value our pension assets and liabilities. Actual results could differ materially from our estimates. In the opinion of management, all adjustments considered necessary for a fair presentation have been included.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid short-term investments with original maturities of three months or less.

Restricted Cash. Restricted cash represents cash that is not readily available for general purpose cash needs. Restricted cash is classified as a current or long-term asset based on the timing and nature of when or how the cash is expected to be used or when the restrictions are expected to lapse. We include all changes in restricted cash in investing cash flows on the consolidated statements of cash flows. Please read Note 12—Debt—Restricted Cash for further discussion.

Accounts Receivable and Allowance for Doubtful Accounts. We record accounts receivable at the net realizable value when the product or service is delivered to the customer. We establish provisions for losses on accounts receivable if it becomes probable that we will not collect all or part of outstanding balances. We review collectability and establish or adjust our allowance as necessary using the specific identification method. Our allowance for doubtful accounts was decreased to zero in connection with the application of fresh-start accounting on the Plan Effective Date. Accounts receivable includes accounts receivable from affiliates of zero and $1 million as of December 31, 2013 and 2012, respectively. Accounts payable includes accounts payable to affiliates of zero and $1 million as of December 31, 2013 and 2012, respectively.

Inventory. Our commodity and materials and supplies inventories are carried at the lower of weighted average cost or market.

Property, Plant and Equipment. Property, plant and equipment, which consist principally of power generating facilities, including capitalized interest, is generally recorded at historical cost. Expenditures for major installations, replacements, and improvements or betterments are capitalized and depreciated over the expected life cycle. Expenditures for maintenance, repairs and minor renewals to maintain the operating condition of our assets are expensed. Depreciation is provided using the straight-line method over the estimated economic service lives of the assets, ranging from one to 36 years.

The estimated economic service lives of our asset groups are as follows:

Asset Group	Range of Years
Power generation facilities	1 to 30
Environmental upgrades	10 to 30
Buildings and improvements	7 to 36
Office and other equipment	2 to 15

Gains and losses on sales of individual assets or asset groups are reflected in Gain on sale of assets, net in the consolidated statements of operations. We assess the carrying value of our property, plant and equipment to determine if an impairment is indicated when a triggering event occurs. If an impairment is indicated, the amount of the impairment loss recognized would be determined by the amount by which the carrying value exceeds the estimated fair value of the assets. The estimated fair value may include estimates based upon discounted cash-flow projections, recent comparable market transactions or quoted prices to determine if an impairment loss is required. For assets classified as held for sale, the book value is compared to the estimated sales price less costs to sell to determine if an impairment is required.

Intangible Assets. We initially record and measure intangible assets based on the fair value of those rights transferred in the transaction in which the asset was acquired. Additionally, we recorded intangible assets in connection with the application of fresh-start accounting. The intangible assets are based on quoted market prices for the asset, if available, or measurement techniques based on the best information available such as a present value of future cash flows. We amortize our definite-lived intangible assets based on the useful life of the respective asset as measured by the life of the underlying contract or contracts. Intangible assets that are not subject to amortization are subjected to impairment testing on an annual basis or when a triggering event occurs, and an impairment loss is recognized if the carrying amount of an intangible asset exceeds its fair value. We do not currently have any intangible assets that are not subject to amortization.

Asset Retirement Obligations. We record the present value of our legal obligations to retire tangible, long-lived assets on our balance sheets as liabilities when the liability is incurred. Our AROs relate to activities such as ash pond and landfill capping, dismantlement of power generation facilities, future removal of asbestos containing material from certain power generation facilities, closure and post-closure costs, environmental testing, remediation, monitoring and land obligations. Accretion expense

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

is included in Operating and maintenance expense on our consolidated statements of operations. A summary of changes in our AROs is as follows:

	Successor		Predecessor	
(amounts in millions)	Year Ended December 31, 2013	October 2 Through December 31, 2012	January 1 Through October 1, 2012	Year Ended December 31, 2011
Beginning of period	$ 83	$ 83	$ 50	$ 120
Accretion expense	6	1	3	6
Divestiture of assets	—	—	—	1
Revision of previous estimate (1)	36	—	(16)	(24)
AER Acquisition (2)	59	—	—	—
DMG Transfer (3)	—	—	—	(53)
DMG Acquisition (3)	—	—	53	—
Fresh-start adjustments	—	—	5	—
Deconsolidation of DNE (4)	—	—	(11)	—
Expenditures	(3)	(1)	(1)	—
End of period	$ 181	$ 83	$ 83	$ 50

(1) During 2013, we revised our ARO upward by $36 million based on observed trends in Illinois primarily related to ash pond closures and groundwater monitoring. During the 2012 Predecessor Period, we revised the South Bay ARO downward by $16 million based on revised cost estimates related to the plant demolition. During 2011, we revised our ARO downward by $24 million based on revised cost estimates related to remediation of asbestos, plant demolition and ash ponds.

(2) As a result of the AER Acquisition on December 2, 2013, the AROs associated with the IPH segment were assumed.

(3) As a result of the DMG Transfer (as defined in Note 3—Merger and Acquisitions—DMG Transfer and DMG Acquisition) on September 1, 2011, the AROs associated with the Coal segment (including DMG) were transferred from DH to Legacy Dynegy and subsequently, as a result of the DMG Acquisition (as defined in Note 3—Merger and Acquisitions—DMG Transfer and DMG Acquisition), the AROs were reacquired on June 5, 2012.

(4) As a result of the deconsolidation of the DNE Debtor Entities, the related AROs are no longer reflected as liabilities on our consolidated balance sheets.

Contingencies, Commitments, Guarantees and Indemnifications. We are involved in numerous lawsuits, claims, proceedings and tax-related audits in the normal course of our operations. We record a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review our loss contingencies on an ongoing basis to ensure that we have appropriate reserves recorded on our consolidated balance sheets. These reserves are based on estimates and judgments made by management with respect to the likely outcome of these matters, including any applicable insurance coverage for litigation matters, and are adjusted as circumstances warrant.

Liabilities for environmental contingencies are recorded when an environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based, in part, on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability.

We disclose and account for various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification is entered into, an estimated fair value of the underlying guarantee or indemnification is recorded. Some guarantees and indemnifications could have significant financial impact under certain circumstances; however, management also considers the probability of such circumstances occurring when estimating the fair value.

Revenue Recognition. We earn revenue from our facilities in three primary ways: (i) the sale of both fuel and energy through both physical and financial transactions to optimize the financial performance of our generating facilities; (ii) the sale of capacity; and (iii) the sale of ancillary services, which are the products of a generation facility that support the transmission grid operation, allow generation to follow real-time changes in load, and provide emergency reserves for major changes to the balance of generation and load. We recognize revenue from these transactions when the product or service is delivered to a customer, unless they meet the definition of a derivative. Please read directly below “Derivative Instruments—Generation” for further discussion of the accounting for these types of transactions.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivative Instruments—Generation. We enter into commodity contracts that meet the definition of a derivative. These contracts are often entered into to mitigate or eliminate market and financial risks associated with our generation business. These contracts include forward contracts, which commit us to sell commodities in the future; futures contracts, which are generally broker-cleared standard commitments to purchase or sell a commodity; option contracts, which convey the right to buy or sell a commodity; and swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined quantity. All derivative commodity contracts that do not qualify for the "normal purchase, normal sale" exception are recorded at fair value in risk management assets and liabilities on the consolidated balance sheets. We elect not to apply hedge accounting to our derivative commodity contracts; therefore, changes in fair value are recorded currently in earnings. As a result, these mark-to-market gains and losses are not reflected in the consolidated statements of operations in the same period as the underlying activity for which the derivative instruments serve as economic hedges. Derivative instruments and related cash collateral or margin that are executed with the same counterparty under a master netting agreement are reflected on a net basis in the consolidated balance sheets.

Cash inflows and cash outflows associated with the settlement of risk management activities are recognized in net cash provided by (used in) operating activities on the consolidated statements of cash flows.

Derivative Instruments—Financing Activities. We are exposed to changes in interest rates through our variable rate debt. In order to manage our interest rate risk, we enter into interest rate swap and cap agreements. We elect not to apply hedge accounting to our interest rate derivative contracts; therefore, changes in fair value are recorded currently in earnings through interest expense.

Fair Value Measurements. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Our estimate of fair value reflects the impact of credit risk. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs are classified as readily observable, market corroborated or generally unobservable. 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 classify fair value balances based on the classification of the inputs used to calculate the fair value of a transaction. The inputs used to measure fair value have been placed in a hierarchy based on priority.

The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using industry-standards models or other valuation methodologies, in which substantially all assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over the counter forwards, options and swaps.
- Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to our needs. At each balance sheet date, we perform an analysis of all instruments and include in Level 3 all of those whose fair value is based on significant unobservable inputs.

The determination of the fair values incorporates various factors. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities. Valuation adjustments are generally based on capital market implied ratings evidence when assessing the credit standing of our counterparties and when applicable, adjusted based on management’s estimates of assumptions market participants would use in determining fair value.

Income Taxes. We file a consolidated U.S. federal income tax return. Illinois Power Holdings, LLC, and its subsidiaries entered into a tax sharing agreement with Dynegy effective December 2, 2013. We use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant differences.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves estimating our actual current tax payable and related tax
expense together with assessing temporary differences resulting from differing tax and accounting treatment of certain items,
such as depreciation for tax and accounting purposes. These differences can result in deferred tax assets and liabilities which
are included within our consolidated balance sheets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Because we operate and sell power in many different states, our effective annual state income tax rate may vary from period to period because of changes in our sales profile by state, as well as jurisdictional and legislative changes by state. As a result, changes in our estimated effective annual state income tax rate can have a significant impact on our measurement of temporary differences. We project the rates at which state tax temporary differences will reverse based upon estimates of revenues and operations in the respective jurisdictions in which we conduct business.

The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. In making this determination, we consider all available positive and negative evidence affecting specific deferred tax assets, including our past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

Accounting for uncertainty in income taxes requires that we determine whether it is more likely than not that a tax position we have taken will be sustained upon examination. If we determine that it is more likely than not that the position will be sustained, we recognize the largest amount of the benefit that is greater than 50 percent likely of being realized upon settlement. We recognize accrued interest expense and penalties related to unrecognized tax benefits as income tax expense.

Please read Note 14—Income Taxes for further discussion of our accounting for income taxes, uncertain tax positions and changes in our valuation allowance.

Earnings (Loss) Per Share. Basic earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period. Diluted earnings per share amounts include the effect of issuing shares of common stock for outstanding stock options, restricted stock units, warrants and performance based stock awards under the treasury stock method if including such potential common shares is dilutive.

Business Combinations Accounting and Fresh-Start Accounting. The Company accounts for its business combinations in accordance with ASC 805, Business Combinations, or ASC 805. ASC 805 requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also requires an acquirer to measure any goodwill acquired and determine what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are expensed as incurred.

Certain companies qualify for fresh-start accounting in connection with their emergence from bankruptcy. Fresh-start accounting is appropriate on the emergence from bankruptcy if the reorganization value of the assets of the emerging entity immediately before the date of confirmation is less than the total of all postpetition liabilities and allowed claims, and if the holders of existing voting shares immediately before confirmation receive less than 50 percent of the voting shares of the emerging entity. We met these requirements on the Plan Effective Date (as defined below) and adopted fresh-start accounting resulting in the creation of a new reporting entity designated as the Successor.

The bankruptcy court issued a confirmation order approving our Plan of reorganization on September 10, 2012 and we met the requirements of the Joint Chapter 11 Plan (the “Plan”) on October 1, 2012 (the “Plan Effective Date”). Under the requirements of fresh-start accounting, we have adjusted our assets and liabilities to their estimated fair values as of October 1, 2012 in conformity with the guidance for the acquisition method of accounting for business combinations.

The net effect of all fresh-start adjustments, including the effects of implementing the plan, resulted in a gain of approximately $1.2 billion, which is reflected in the 2012 Predecessor Period. The application of the fresh-start provisions created a new reporting entity having no retained earnings nor accumulated deficit.

Our fresh-start adjustments consist primarily of (i) estimates of the fair value of our existing fixed assets and liabilities and (ii) recognition of the fair value of certain sales, coal purchase and transportation contracts, with terms that were not at current market value, as either intangible assets or liabilities. These intangible assets and liabilities will be amortized into income over the respective terms of each contract. A description of the adjustments and amounts is provided in Note 21—Emergence from Bankruptcy and Fresh-Start Accounting.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Due to the application of the fresh-start accounting upon our emergence from bankruptcy, the Successor's consolidated financial statements have not been prepared on a consistent basis with the Predecessor's financial statements and are therefore not comparable.

Accounting Standards Adopted

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 6—Accumulated Other Comprehensive Income (Loss) for further discussion.

Disclosures about Offsetting Assets and Liabilities. In December 2011, the FASB issued ASU 2011-11-Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. The FASB added clarification to this guidance in ASU 2013-01-Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. This new guidance requires entities to disclose both gross and net information about instruments and transactions eligible for offsetting in the statement of financial position, as well as instruments and transactions subject to an agreement similar to a master netting arrangement. ASU 2011-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. Please read Note 4—Risk Management Activities, Derivatives and Financial Instruments for further discussion.

Accounting Standards Not Yet Adopted

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

Joint and Several Liability Arrangements. In February 2013, the FASB issued ASU 2013-04-Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date. The provisions of the rule require an entity to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, as the sum of (i) the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and (ii) any additional amount the reporting entity expects to pay on behalf of its co-obligors. The guidance in this update also requires an entity to disclose the nature and amount of the obligation as well as other information about those obligations. ASU 2013-04 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. We are currently assessing the future impact of this update, but we do not anticipate a material impact on our financial condition, results of operations or cash flows.

Note 3—Merger and Acquisitions

AER Transaction Agreement

On December 2, 2013, pursuant to the terms of the definitive agreement dated as of March 14, 2013 (the "AER Transaction Agreement") by and between Illinois Power Holdings, LLC ("IPH"), an indirect wholly-owned subsidiary of Dynegy, and Ameren Corporation ("Ameren"), IPH completed its acquisition from Ameren of 100 percent of the equity interests of New Ameren Energy Resources, LLC (“AER”) and its subsidiaries (the “AER Acquisition”). Pursuant to the AER Transaction Agreement, IPH indirectly acquired AER’s subsidiaries, including (i) Ameren Energy Generating Company (“AEGC”), including its 80 percent ownership interest in EEI, (ii) New AERG, LLC (“AERG”), (iii) Ameren Energy Fuels and Services Company and (iv) Ameren Energy Marketing Company (“AEM”). Dynegy has provided a limited guaranty of certain obligations of IPH up to $25 million (the “Limited Guaranty”) as further described in Note 16—Commitments and Contingencies—Guarantees. We acquired AER and its subsidiaries through IPH which will maintain corporate separateness from our legal entities outside of IPH.

DYNEGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The acquisition added 4,062 MW of generation in Illinois and also included the Homefield Energy retail business. There was no cash consideration or stock issued as part of the purchase price.

In connection with the AER Acquisition, the following legal name changes occurred: (i) AER changed to Illinois Power Resources, LLC (“IPR”), (ii) AEGC changed to Illinois Power Generating Company (“IPGC” or AEGC, “Genco”), (iii) AERG changed to Illinois Power Resources Generating, LLC (“IPRG”), (iv) Ameren Energy Fuels and Services Company changed to Illinois Power Fuels and Services Company and (v) AEM changed to Illinois Power Marketing Company (“IPM”).

On December 2, 2013, prior to the completion of the AER Acquisition, IPH and Ameren entered into an amendment to the AER Transaction Agreement, in the form of a letter agreement (the “Letter Agreement”). The Letter Agreement, among other things, (i) identified additional post-closing credit support Ameren is to provide to IPH pursuant to the terms therein, (ii) provided that Ameren will be obligated to pay an additional amount of between $25 million and $35 million with respect to certain disputed wholesale customer contracts, (iii) provided that Ameren would cause an additional approximately $4 million of cash, in aggregate, to be retained at IPM, (iv) provided that Ameren will be contingently liable up to approximately $4 million with respect to certain railroad lease termination fees, (v) requires Ameren to maintain and continue certain guarantees in connection with certain existing contractual obligations, pursuant to the terms therein and (vi) requires Ameren to provide post-closing litigation support to IPH in connection with certain disputes under specified contracts.

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

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

Additionally, effective December 2, 2013, immediately upon completion of the AER Acquisition, we entered into a revolving promissory note as lender (the “Note”) with IPR. The Note is in the principal amount of $25 million or such lesser amount as will equal the aggregate unpaid principal amount of all loans (“Loans”). IPR is to repay the Loans plus 7.75 percent interest by December 2, 2015 unless extended in Dynegy’s sole discretion (the “Maturity Date”), to the extent such principal amount and interest has not been repaid by the Maturity Date. After the date any principal amount of any Loan is du