DYNEGY HOLDINGS INC
Form 10-K
February 26, 2009

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

FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

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

Entity	Commission File Number	State of Incorporation	I.R.S. Employer Identification No.
Dynegy Inc.	001-33443	Delaware	20-5653152
Dynegy Holdings Inc.	000-29311	Delaware	94-3248415

1000 Louisiana, Suite 5800 **Houston, Texas** **(Address of principal executive offices)**	**77002** **(Zip Code)**

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Dynegy s Class A common stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of each class	Name of each exchange on which registered
None	None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Dynegy Inc.	Yes þ No o
Dynegy Holdings Inc.	Yes o No þ

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.

Dynegy Inc.	Yes o No þ
Dynegy Holdings Inc.	Yes o No þ

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 the filing requirements for the past 90 days.

Dynegy Inc.	Yes þ No o
Dynegy Holdings Inc.	Yes þ No o

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.

Dynegy Inc.	o
Dynegy Holdings Inc.	þ

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 definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
Dynegy Inc.	þ	o	o	o
Dynegy Holdings Inc.	o	o	þ	o

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

Dynegy Inc.	Yes o No þ
Dynegy Holdings Inc.	Yes o No þ

As of June 30, 2008, the aggregate market value of the Dynegy Inc. common stock held by non-affiliates of the registrant was $4,298,466,775 based on the closing sale price as reported on the New York Stock Exchange.

Number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date: For Dynegy Inc., Class A common stock, $0.01 par value per share, 503,666,984 shares outstanding as of February 20, 2009; Class B common stock, $0.01 par value per share, 340,000,000 shares outstanding as of February 20, 2009. All of Dynegy Holdings Inc. s outstanding common stock is owned indirectly by Dynegy Inc.

This combined Form 10-K is separately filed by Dynegy Inc. and Dynegy Holdings Inc. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to a registrant other than itself.

DOCUMENTS INCORPORATED BY REFERENCE-Dynegy Inc. Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Notice and Proxy Statement for the registrant s 2009 Annual Meeting of Stockholders, which the registrant intends to file not later than 120 days after December 31, 2008.

REDUCED DISCLOSURE FORMAT-Dynegy Holdings Inc. Dynegy Holdings Inc. meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and therefore is filing this Form 10-K with the reduced disclosure format.

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PART IV

EXPLANATORY NOTE

This report includes the combined filing of Dynegy Inc. (Dynegy) and Dynegy Holdings Inc. (DHI). DHI is the principal subsidiary of Dynegy, providing approximately 100 percent of Dynegy s total consolidated revenue for the year ended December 31, 2008 and constituting approximately 100 percent of Dynegy s total consolidated asset base as of December 31, 2008 except for Dynegy s former 50 percent interest in DLS Power Holdings, LLC (DLS Power Holdings) and DLS Power Development Company, LLC (DLS Power Development).

Unless the context indicates otherwise, throughout this report, the terms the Company , we , us , our and ours are u refer to both Dynegy and DHI and their direct and indirect subsidiaries. Discussions or areas of this report that apply only to Dynegy or DHI are clearly noted in such discussions or areas.

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PART I

DEFINITIONS

As used in this Form 10-K, the abbreviations contained herein have the meanings set forth in the glossary, which can be found in the Notes to Consolidated Financial Statements.

Item 1. *Business*

THE COMPANY

We are holding companies 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 twenty-seven operating power plants in thirteen states totaling nearly 18,000 MW of generating capacity.

Dynegy began operations in 1985. DHI is a wholly owned subsidiary of Dynegy. Dynegy became incorporated in the State of Delaware in 2007 as a part of the LS Power transaction. Our principal executive office is located at 1000 Louisiana Street, Suite 5800, Houston, Texas 77002, and our telephone number at that office is (713) 507-6400.

We file annual, quarterly and current reports, proxy statements (for Dynegy Inc.) 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 web site at *www.sec.gov*. No information from such web site is incorporated by reference herein. Our SEC filings are also available free of charge on our web site 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.

We sell electric energy, capacity and ancillary services on a wholesale basis from our power generation facilities. Energy is the actual output of electricity and is measured in MWh. The capacity of a generation facility is its electricity production capability, measured in MW. 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 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. We sell these products individually or in combination to our customers under short-, medium- and long-term contractual agreements or tariffs.

Our customers include RTOs and ISOs, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, industrial customers, power marketers, financial participants such as banks and hedge funds, other power generators and commercial end-users. All of our products are sold on a wholesale basis for various lengths of time from hourly to multi-year transactions. 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.

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Our Strategy

Our business strategy is designed to leverage our diverse portfolio of generating assets, our operational and commercial skills and our flexible capital structure to create value for our investors. In general, we seek to maximize the value of our assets through:

- safe and cost-efficient plant operations, with a focus on having our plants available and in the market when it is economical to do so;
- a diverse commercial strategy that includes short-, medium- and long-term sales of electric energy, capacity and ancillary services, and seeks to strike a balance between contracting for near/intermediate term stability of earnings and cash flows while maintaining merchant length to capitalize on expected increases in commodity prices in the longer term; and
- pursuit of plant expansions and growth opportunities that enhance our portfolio with acceptable rates of return and are accretive to stockholder value.

Maintain a Diverse Portfolio to Capitalize on Market Opportunities and Mitigate Risk. We operate a portfolio of generation assets that is diversified in terms of dispatch profile, fuel type and geography. Baseload generation is low-cost and economically attractive to dispatch around the clock throughout the year. A baseload facility is usually expected to run between 80 percent and 90 percent of the hours in a given year. Intermediate generation is not as efficient and/or economical as baseload generation but is intended to be dispatched during higher load times such as during daylight hours and sometimes on weekends. Peaking generation is the least efficient and highest cost generation and is generally dispatched to serve load during the highest load times such as hot summer and cold winter days.

Although power prices have declined since the summer of 2008, primarily due to the oversupply of natural gas in the market and the impact of the current economic environment, we continue to believe that the market fundamentals support long-term increases in power demand and power pricing. As such, we believe our substantial coal-fired, baseload fleet should benefit from the impact of higher power prices in the Midwest and Northeast, allowing us to capture significantly higher and increasing margins over the long-term as power prices increase. We anticipate that our combined cycle units also should benefit from improved margins and cash flows as demand increases in all of our key markets. Our peaking units effectively give us an option to capture greater value for our investors as supply and demand come more into equilibrium over the longer term.

In addition, we believe that a diverse portfolio of assets helps to mitigate the risks inherent in our business. For example, weather patterns, regulatory regimes and commodity prices often differ by region. By maintaining fleet diversity, we lessen the impact of an individual risk in any one region and seek to improve the level and consistency of our earnings and cash flows. We also believe our diverse fleet of generating assets positions us well to meet growing U.S. power needs; however, in the current recessionary environment, U.S. power consumption may decrease in the short-term.

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Our current operating 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
Kendall	1,200	Gas	Intermediate	Minooka, IL	PJM
Ontelaunee	580	Gas	Intermediate	Ontelaunee Township, PA	PJM
Havana Units 1-5	228	Oil	Peaking	Havana, IL	MISO
Unit 6	441	Coal	Baseload	Havana, IL	MISO
Hennepin	293	Coal	Baseload	Hennepin, IL	MISO
Oglesby	63	Gas	Peaking	Oglesby, IL	MISO
Stallings	89	Gas	Peaking	Stallings, IL	MISO
Tilton	188	Gas	Peaking	Tilton, IL	MISO
Vermilion Units 1-2	164	Coal/Gas	Baseload	Oakwood, IL	MISO
Unit 3	12	Oil	Peaking	Oakwood, IL	MISO
Wood River Units 1-3	119	Gas	Peaking	Alton, IL	MISO
Units 4-5	446	Coal	Baseload	Alton, IL	MISO
Rocky Road (2)	330	Gas	Peaking	East Dundee, IL	PJM
Riverside/Foothills	960	Gas	Peaking	Louisa, KY	PJM
Renaissance	776	Gas	Peaking	Carson City, MI	MISO
Bluegrass	576	Gas	Peaking	Oldham County, KY	SERC
Total Midwest	*8,265*				
Moss Landing Units 1-2	1,020	Gas	Intermediate	Monterrey County, CA	CAISO
Units 6-7	1,509	Gas	Peaking	Monterrey County, CA	CAISO
Morro Bay (3)	650	Gas	Peaking	Morro Bay, CA	CAISO
South Bay	706	Gas/Oil	Peaking	Chula Vista, CA	CAISO
Oakland	165	Oil	Peaking	Oakland, CA	CAISO
Arlington Valley	585	Gas	Intermediate	Arlington, AZ	Southwest
Griffith	558	Gas	Intermediate	Golden Valley, AZ	WAPA
Heard County (4)	539	Gas	Peaking	Heard County, GA	SERC
Black Mountain (5)	43	Gas	Baseload	Las Vegas, NV	WECC
Total West	*5,775*				
Independence	1,064	Gas	Intermediate	Scriba, NY	NYISO
Roseton (6)	1,185	Gas/Oil	Peaking	Newburgh, NY	NYISO
Bridgeport	527	Gas	Intermediate	Bridgeport, CT	ISO-NE
Casco Bay	540	Gas	Intermediate	Veazie, ME	ISO-NE
Danskammer Units1-2	123	Gas/Oil	Peaking	Newburgh, NY	NYISO
Units 3-4 (6)	370	Coal/Gas	Baseload	Newburgh, NY	NYISO

Total Northeast	*3,809*
Total Fleet Capacity	*17,849*

(1) Unit capacity values are based on winter capacity.

(2) Does not include 28 MW of capacity for unit 3, which is not available during cold weather because of winterization requirements.

(3) Represents units 3 and 4 generating capacity. Units 1 and 2, with a combined net generating capacity of 352 MW, are currently in lay-up status and out of operation.

(4) On February 25, 2009, we entered into an agreement to sell our interest in the Heard County power generation facility to Oglethorpe Power Corporation. Subject to regulatory approval, the transaction is expected to close in early 2009. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Heard County for further discussion.

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

(6) We lease the Roseton facility and units 3 and 4

of the Danskammer facility pursuant to a leveraged lease arrangement that is further described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Disclosure of Contractual Obligations and Contingent Financial Commitments Off-Balance Sheet Arrangements DNE Leveraged Lease.

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Operate our Assets Safely and Cost-Efficiently to Maximize Revenue Opportunities and Operating Margins. We have a history of strong plant operations and are committed to operating our facilities in a safe, reliable and environmentally compliant manner. By maintaining and operating our assets in an effort to ensure plant availability, high dispatch and capacity factors and an appropriate level of operating and capital costs, we believe we are positioned to capture opportunities in the market place effectively and to maximize our operating margins.

With respect to cost controls, a key aspect of profitability is our cost to produce electricity. The main variable component of that cost is fuel. Our coal-fired generation facilities are our lowest variable cost facilities. Due to their low-cost nature, most of our coal-fired generation facilities run the majority of any given day throughout the year unless a particular unit is unavailable due to either planned or unplanned maintenance activity. In today s environment, our natural gas and fuel oil-fired power generation facilities are more expensive to operate than our coal-fired facilities. As a result, these plants only run on those days, or parts of days, when market demand and price are sufficient to economically justify dispatch of these higher cost units.

Our power generation facilities are managed to require a relatively predictable level of maintenance capital expenditures without compromising operational integrity. Our capital expenditures are for the maintenance of our facilities to ensure their continued reliability and for investment in new equipment for either environmental compliance or increasing profitability. We seek to operate and maintain our generation fleet efficiently and safely, with an eye toward future maintenance and improvements, resulting in increased reliability and environmental stewardship. This increased reliability impacts our results to the extent that our generation units are available during times that it is economically sound to run. For units that are subject to contracts for capacity, our ability to secure availability payments from customers is dependent on plant availability. We believe these ongoing efforts to focus on reliability should allow us to maintain focus on being a low-cost producer of power.

Employ a Flexible Commercial Strategy to Maintain Long-Term Market Upside Potential While Protecting Against Downside Risks. We expect to see tightening reserve margins through time in the regions in which our assets are located. As these reserve margins tighten, we expect to see the value of the generating assets themselves increase due to improvements in cash flow and earnings. When prices that equate to market recovery are transactable, longer-term contracts are advisable. However, given current market pricing and conditions, we do not see attractive long-term commercial arrangements.

We plan to sell the output from our facilities with the goal of achieving an efficient balance of risk and reward. Keeping the portfolio completely open and selling in the day-ahead market, for instance, would force us to take weather and general economic-related risks, as well as price risk of correlated commodities. These risks can cause significant swings in financial performance in any one year and are not related to our core strategy of realizing the benefit of long-term market recovery on fundamental generating asset values.

With a goal of protecting cash flow in the near/intermediate term while maintaining the ability to capture value longer term as markets tighten, we expect that a majority of our sales will be achieved by selling energy and capacity through a combination of spot market sales and near-term contracts over a rolling 12 36 month time frame in time periods that we describe as Current , Current +1 , and Current +2 . The Current period refers to the balance of the current calenda year. The Current+1 period refers to the next calendar year. Current +2 refers to the next calendar year after the Current +1 period. At any given point in time, we will seek to balance predictability of earnings and cash flow with achieving the highest level of earnings and cash flow possible over the Current, Current +1 and Current +2 periods. In these periods, short-term market volatility can negatively impact our profitability and we will seek to reduce those negative impacts through the disciplined use of near- and intermediate-term forward sales. We expect to make fewer forward sales beyond the Current+2 period in order to realize the anticipated benefit of improved market prices over time as the supply and demand balance tightens.

Beginning in January 2009, we have set specific limits for gross margin at risk for the entire portfolio and require power hedging up to minimum levels, while seeking to ensure that corresponding fuel supplies also are appropriately hedged, as we progress through time. We will also specifically manage basis risk to hubs that are not the natural sales hub for a facility and implement other changes that sharpen our focus on optimizing the commercial factors that we can control and mitigating commodity risk where appropriate.

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Maintain a Simple, Flexible Capital Structure that is Integrated with our Operating Strategy. We believe that the power industry is a commodity cyclical business with significant commodity price volatility and considerable capital investment requirements. Thus, maximizing economic returns in this market environment requires a capital structure that can withstand fuel and power price volatility as well as a commercial strategy that captures the value associated with both mid- and long-term price trends. We believe we have a capital structure that is suitable for our commercial strategy and the commodity cyclical market in which we operate. Maintaining appropriate debt levels and covenants, maturities and overall liquidity are key elements of this capital structure. This structure allows us to be opportunistic as we regularly evaluate potential combinations or asset acquisitions. We will also seek to harvest value through the opportunistic sale of existing assets where we believe we can capture greater value through a sale than we can by continuing to own or operate such assets.

SEGMENT DISCUSSION

Our business operations are focused primarily on the wholesale power generation sector of the energy industry. We report the results of our power generation business, based on geographical location and how we allocate resources, as three separate segments in our consolidated financial statements: (i) GEN-MW, (ii) GEN-WE and (iii) GEN-NE. The results of our former CRM segment are included in Other, as it did not meet the criteria required to be an operating segment as of January 1, 2008. Accordingly, we have restated the corresponding items of segment information for prior periods. Our consolidated financial results also reflect corporate-level expenses such as general and administrative and interest. Please read Note 22 Segment Information for further information regarding the financial results of our business segments.

NERC Regions, RTOs and ISOs. In discussing our business, we often refer to NERC regions. The NERC and its eight regional reliability councils (as of December 31, 2008) were formed to ensure the reliability and security of the electricity system. The regional reliability councils set standards for reliable operation and maintenance of power generation facilities and transmission systems. For example, each NERC region establishes a minimum 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 each region.

Separately, RTOs and ISOs administer the transmission infrastructure and markets across a regional footprint in some 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 reserve through monthly, semi-annual, annual and multi-year capacity markets. The RTOs and ISOs that oversee most of the wholesale power markets 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 power in these markets. NERC regions and RTOs/ISOs often have different geographic footprints and while there may be physical 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, and zonal clearing structures (e.g. the ERCOT Region in Texas), 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 megawatt hour 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 losses and congestion). For example, a less-efficient (i.e., more expensive) 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 (although the price paid at other zones or locations may vary because of congestion and losses), 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 pricing clearing structures (e.g. PJM, NYISO, and ISO-NE), generators receive the location-based marginal price for their output. In regions that are outside the footprint of RTOs/ISOs, prices are determined on a bilateral basis between buyers and sellers.

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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, Dynegy Power Marketing Inc. and Dynegy Marketing and Trade LLC. The Dynegy EWG facilities include all of our facilities except our investments in Nevada Cogeneration Associates #2 (Black Mountain), Allegheny Hydro Partners, Ltd., Allegheny No. 6 Hydro Partners, Ltd, Allegheny Hydro No. 8 Ltd. and Allegheny Hydro No. 9, Ltd. These facilities are known as QFs, and have various exemptions from federal regulation and sell electricity directly to purchasers under negotiated and previously approved power purchase agreements. Our market-based rate authority is predicated on a finding by FERC that our entities with market-based rates do not have market power, and a market power analysis is generally conducted once every three years for each region on a rolling basis (known as the triennial market power review). The triennial market power review for our Northeast and PJM assets was filed at FERC on August 29, 2008. FERC issued an order accepting this filing on December 12, 2008. The triennial market power review for our Southeast assets was filed with FERC on December 24, 2008. The triennial market power reviews for our West and MISO assets will be filed pursuant to a FERC established schedule.

Power Generation Midwest Segment

Our Midwest fleet is comprised of 14 facilities located in Illinois (10), Michigan (1), Pennsylvania (1) and Kentucky (2), with a total generating capacity of 8,265 MW. With the exception of our Bluegrass peaking facility in the Louisville Gas and Electric control area, our Midwest fleet as of December 31, 2008 operates entirely within either the MISO or the PJM.

RTO/ISO Discussion

MISO. The MISO market includes all of Wisconsin and Michigan and portions of Ohio, Kentucky, Indiana, Illinois, Nebraska, Kansas, Missouri, Iowa, Minnesota, North Dakota, Montana and Manitoba, Canada. As of December 31, 2008, we owned nine power generating facilities located in Illinois (8) and Michigan (1), with an aggregate net generating capacity of 4,619 MW within MISO.

MISO is designed to ensure that every electric industry participant has access to the grid and that no entity has the ability to deny access to a competitor. MISO also manages the use of transmission lines to make sure that they do not become overloaded. MISO operates physical and financial energy markets using a system known as LMP, which calculates a price for every generator and load point within the MISO area. This system is price-transparent , allowing generators and load serving entities to see real-time price effects of transmission constraints and impacts of generation and load changes to prices at each point. MISO operates day-ahead and real-time markets into which generators can offer to provide energy. 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 plans to implement an enforceable Planning Reserve Margin for the 2009-2010 planning year. 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. An independent market monitor is responsible for ensuring that MISO markets are operating competitively and without exercise of market power.

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. As of December 31, 2008, we owned four generating facilities located in Illinois (2), Pennsylvania (1) and Kentucky (1) with an aggregate net generating capacity of 3,070 MW within PJM. The majority of power generated by these facilities is sold to wholesale customers in the PJM market.

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 electricity and ancillary services. PJM also administers markets for capacity. An independent market monitor continually monitors PJM markets for any exercise of market power or improper behavior by any entity. PJM implemented a forward capacity auction, the RPM, which established long-term markets for capacity in 2007. The RPM has provided locational price and multi-year dimensions to the capacity market, but has also led to some controversy. In December 2008, FERC responded to complaints about the new RPM rules by establishing a settlement proceeding to create a forum for capacity buyers and capacity suppliers to find common ground. The settlement discussions were not successful and have been terminated. On December 12, 2008, PJM filed tariff revisions with FERC to make important enhancements to the RPM rules in time for the May 2009 forward auction. PJM has requested an effective date of March 27, 2009 for its proposed tariff revisions.

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 costly supplier offers or bids to create reliable and least-cost dispatch. The ISO-sponsored 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) existing $1,000/MWh energy market price caps that are in place.

Contracted Capacity and Energy

MISO. Power prices are a significant driver of our financial performance due to the fact that a significant portion of our power generating capacity in the MISO is attributable to coal-fired baseload units. In MISO, we have entered into a mix of bilateral contracts and physical and financial over-the-counter energy sales for 2009 and 2010 with limited forward sales beyond 2010.

PJM. Our generation assets in PJM are either intermediate dispatch or peaking facilities. We commercialize these assets through a combination of bilateral sales and sales into the RPM auction. Additionally, approximately 280 MW of capacity at our Kendall facility is contracted under a tolling agreement through 2017.

Regulatory Considerations

In January 2006, the ICC approved a reverse power procurement auction as the process by which utilities would procure power beginning in 2007. The initial auction occurred in September 2006, and we subsequently entered into two supplier forward contracts with subsidiaries of Ameren to provide capacity, energy and related services. The Illinois legislature passed legislation in 2007 as part of the Illinois rate relief package that significantly altered the power procurement process in Illinois; but the contracts with the Ameren subsidiaries remain in effect.

In July 2007, legislative leaders in the State of Illinois announced a comprehensive transitional rate relief package for electric consumers. This program will provide approximately $1 billion to help provide assistance to utility customers in Illinois and fund a new power procurement agency. As part of this rate relief package, we will make payments of up to $25 million over a 29-month period. These payments will be contingent on certain conditions related to the absence of future electric rate and tax legislation in Illinois. We made payments of $7.5 million in 2007 and $9 million in 2008 and anticipate making a final payment of $8.5 million in 2009.

Construction Project

Plum Point. We own an approximate 37 percent interest in PPEA Holding Company LLC (PPEA), which, through its wholly owned subsidiary, owns an approximate 57 percent undivided interest in the Plum Point Energy Station (Plum Point), a 665 MW coal-fired power generation facility under construction in Mississippi County, Arkansas. Plum Point is currently expected to commence commercial operations by August 2010. All of PPEA s 378 MW have been contracted for an initial 30-year period. The PPAs provide for a pass-through of commodity, fuel, transportation and emissions expenses. The joint owners of Plum Point initially selected us as the construction manager of the project. However, on December 31, 2008, we gave notice of our intention to terminate an agreement under which we are acting as operator of Plum Point. It is anticipated that this agreement will be terminated effective on or before April 30, 2009. We have previously indicated that we consider Plum Point a non-core asset and intend to pursue alternatives regarding our remaining ownership interest.

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Power Generation West Segment

Our West fleet is comprised of seven predominantly natural gas-fired power generation facilities, located in California (3), Arizona (2), Georgia (1) and Nevada (1), and one fuel oil-fired power generation facility, located in California, totaling 5,775 MW of electric generating capacity.

RTO/ISO Discussion

CAISO. CAISO covers approximately 90 percent of the state of California. At December 31, 2008, we owned four generating facilities in California with an aggregate net generating capacity of 4,050 MW within CAISO. The South Bay and Oakland facilities are designated as RMR units by the CAISO.

Southwest Region. The Southwest region covers Arizona, Nevada, Colorado, Utah and portions of New Mexico but is not formally structured as an RTO/ISO. At December 31, 2008, we owned two combined cycle generating facilities located in Arizona with an aggregate net generating capacity of 1,143 MW located within the Southwest region. Griffith is subject to WAPA control area requirements, while Arlington Valley is in a generation-only control area operated by Constellation Energy (Constellation).

SERC. The SERC Reliability Corporation is the regional entity covering a majority of the southeast states. At December 31, 2008, we owned one natural gas-fired peaking generation facility in Georgia with an aggregate net generating capacity of 539 MW located in the SERC area. SERC is the regional entity with delegated authority from NERC and is responsible for promoting, coordinating and ensuring the reliability and adequacy of the bulk power supply systems in the southeast region. On February 25, 2009, we entered into an agreement to sell our interest in the Heard County power generation facility to Oglethorpe Power Corporation. Subject to regulatory approval, the transaction is expected to close in the first half of 2009. Please read Note 4 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Heard County for further discussion.

Contracted Capacity and Energy

CAISO. In the CAISO region, where our assets include intermediate dispatch and peaking facilities, we seek to mitigate spark spread variability through RMR and tolling arrangements, as well as heat rate call options. To that end, all of the capacity of our Moss Landing units 6 and 7 and Morro Bay facility are contracted under tolling arrangements through 2010 and 2013, respectively. Our Oakland facility operates under an RMR contract from year to year. Our South Bay facility will also likely operate under an RMR contract upon completion of its current tolling arrangement at the end of 2009. With respect to Moss Landing units 1 and 2, we seek to mitigate our exposure to changes in the market price of energy through a financially-settled heat rate call-option on 750 MW through September 2010.

Southwest Region. In the Southwest region, we operate two intermediate dispatch facilities. Volumes generated by these facilities can vary significantly depending on changes in spark spreads. Therefore, we seek to manage this risk by entering into tolling arrangements. The full capacity of our Griffith facility is contracted under a summer tolling agreement from June through September through 2017. Additionally, we have entered into a summer tolling agreement for our Arlington Valley facility, which will be in place for June through September 2010 and 2011 and from May through October of 2012 through 2019.

Regulatory Considerations

CAISO. CAISO s proposal to implement MRTU has experienced numerous delays and is now expected to launch on March 31, 2009. MRTU is intended to improve management of California s transmission grid, provide clear rules for wholesale buyers and sellers and allow market prices to reflect actual costs.

On the state level, there are numerous other ongoing market initiatives that impact wholesale generation, principally the development of resource adequacy rules and capacity markets.

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Equity Investment and Construction Project

Black Mountain. We have a 50 percent indirect ownership interest in the Black Mountain plant, 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 runs to 2023.

Sandy Creek. SCH has a 50 percent ownership interest in SCEA, which owns an approximate 64 percent undivided interest in the Sandy Creek Energy Station, an 898 MW coal-fired power generation facility under construction in McLennan County, Texas. We anticipate commercial operations will begin in 2012. Of the expected plant output associated with SCEA s 64 percent undivided interest, 250 MW have been contracted for an initial 30-year period. The PPAs provide for a pass-through of commodity, fuel, transportation and emissions expenses. Similar contracts for additional output will be sought as plant construction proceeds. SCEA s share of the construction cost is being financed through project debt and equity. We have previously indicated that we consider Sandy Creek a non-core asset and intend to pursue alternatives regarding our remaining ownership interest.

Power Generation Northeast Segment

Our Northeast fleet is comprised of five facilities located in New York (3), Connecticut (1) and Maine (1), with a total capacity of 3,809 MW. We own and operate the Independence, Bridgeport, Casco Bay and Danskammer Units 1 and 2 power generating facilities, and we operate the Roseton and Danskammer Units 3 and 4 power generating facilities under long-term lease arrangements. Our Roseton and Danskammer facility sites are adjacent and share common resources such as fuel handling, a docking terminal, personnel and systems.

RTO/ISO Discussion

The Northeast region is characterized by two interconnected and actively traded competitive markets: the NYISO (an ISO) and the ISO-NE (an RTO). In the Northeast markets, load-serving entities generally lack their own generation capacity, with much of the generation base aging and the current ownership of the generation spread among several unaffiliated operators. Thus, commodity prices are more volatile on an as-delivered basis than in other regions due to the distance and occasional physical constraints that impact the delivery of fuel into the region.

Although both Northeast RTOs/ISOs and their respective energy markets are functionally, administratively and operationally independent, they follow, to a certain extent, similar market designs. Both the NYISO and the ISO-NE dispatch power plants to meet system energy and reliability needs and settle physical power deliveries at LMPs as discussed above. The energy markets in both the NYISO and ISO-NE also have defined, but different, mitigation protocols for bidding.

In addition to energy delivery, the NYISO and ISO-NE administer markets for installed capacity, ancillary services and FTRs.

NYISO. The NYISO market includes virtually the entire state of New York. At December 31, 2008, we operated three facilities in New York with an aggregate net generating capacity of 2,742 MW within NYISO. In 2003, NYISO implemented a Demand Curve mechanism for calculating the price and quantity of installed capacity to be procured statewide, with capacity prices determined for the two locational zones (New York City and Long Island), and for the New York Control Area at large. Our facilities operate outside of the New York City and Long Island locational zones.

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 has enough revenue to maintain operations when capacity revenues are coupled with energy and ancillary service revenues. Additionally, the Demand Curve mechanism is intended to attract new investment in generation in the locations in which it is needed most when that new capacity is needed.

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Due to transmission constraints, energy prices vary across New York and are generally higher in the Eastern part of New York, where our Roseton and Danskammer facilities are located, and in New York City. Our Independence facility is located in the Northwest part of the state. Current reserve margins are somewhat above the NYISO s current required reserve margin of 15 percent. The New York State Reliability Council has filed a request with FERC to increase the required reserve margin for the May 1, 2009 to April 30, 2010 Capability Year to 16.5 percent.

ISO-NE. The ISO-NE market includes Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. As of December 31, 2008, we owned and operated two power generating facilities within the ISO-NE footprint one in Connecticut and one in Maine, with an aggregate net generating capacity of 1,067 MW within ISO-NE. ISO-NE is in the process of implementing a FCM.

Contracted Capacity and Energy

NYISO. We commercialize the majority of our assets by entering into a mix of bilateral contracts and both physical and financial over-the-counter energy sales for 2009 and 2010.

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 price of power at Pleasant Valley 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.

For the uncommitted portion of our NYISO fleet, 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 our remaining capacity into the market each month. This provides relatively stable capacity revenues at market prices from our facilities both in the short-term and for the foreseeable future.

ISO-NE. We receive monthly fixed transitional capacity payments for all of our 1,067 MW of ISO-NE generating capacity in accordance with the terms of the FCM settlement described below.

Regulatory Considerations

The ISO-NE is in the process of completing its implementation of FCM with capacity delivery under FCM starting in June 2010. The transitional payments for capacity commenced in December 2006 and run through May 31, 2010. The prices start at $3.05/KW-month and increase at defined intervals (discussed below) leading to an ending price of $4.10/KW-month. On June 1, 2010, capacity compensation will be determined through the FCM market. The first auction for the 2010/2011 Capacity Commitment Period (June 1, 2010 through May 31, 2011) was held in February 2008 and resulted in excess capacity remaining at the auction floor price of $4.50/kW-month. The second auction for the 2011/2012 Capacity Commitment Period (June 1, 2011 through May 31, 2012) was held in December 2008 and resulted in excess capacity remaining at the auction floor price of $3.60/kW-month. The third auction for the 2012/2013 Capacity Commitment Period (June 1, 2012 through May 31, 2012) will be held in October 2009. During the transition from the pre-existing capacity markets in ISO-NE to the FCM, all listed ICAP resources can receive monthly capacity payments at the relevant transition period rate up to its audited rating. Both of Dynegy s facilities in ISO-NE (i.e., Bridgeport and Casco Bay) are eligible to receive the transition payments and sell and be paid for their capacity under the FCM.

In 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.

Other

Corporate governance roles and functions, which are managed on a consolidated basis, and specialized support functions such as finance, accounting, risk control, tax, legal, human resources, administration and information technology, are included in Other in our segment reporting. Corporate general and administrative expenses, income taxes and interest expenses are also included, as are corporate-related other income and expense items. Results for our former CRM segment, which primarily consists of a minimal number of power and natural gas trading positions, are also included in this segment in prior periods where appropriate.

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ENVIRONMENTAL MATTERS

Our business is subject to extensive federal, state and local laws and regulations governing discharge of materials into the environment. We are committed to operating within these 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 require unprofitable or unfavorable operating conditions or significant capital and operating expenditures. Failure to acquire or maintain permits or to otherwise comply with applicable rules and regulations may result in fines and penalties or negatively impact our ability to advance projects in a timely manner or at all. Interpretations of existing regulations may change, subjecting historical maintenance, repair and replacement activities at our facilities to claims of noncompliance.

Our aggregate expenditures (both capital and operating) for compliance with laws and regulations related to the protection of the environment were approximately $245 million in 2008 compared to approximately $108 million in 2007 and approximately $60 million in 2006. The 2008 expenditures include approximately $215 million for projects related to our Consent Decree (which is discussed below) compared to $71 million for Consent Decree projects in 2007. We estimate that total environmental expenditures in 2009 will be approximately $300 million, including approximately $280 million in capital expenditures and approximately $20 million in operating expenditures. Changes in environmental regulations or outcomes of litigation and administrative proceedings could result in additional requirements that would necessitate increased future spending and potentially adverse operating conditions. Please read Item 1. Business Environmental Matters and Note 19 Commitments and Contingencies for further discussion of this matter.

Climate Change

For the last several years, there has been an ongoing public debate about climate change, or global warming, and the need to reduce emissions of greenhouse gases (GHG), primarily CO_2 and methane emissions. While no federal legislation has been enacted to control GHG emissions, several state regulatory initiatives are being developed or implemented to reduce GHG emissions, as discussed below. Our position is that since climate change is a global issue, any regulation of GHG emission sources in the United States should be undertaken by the federal government in coordination with developed and developing countries around the world. We believe that the focus of any federal program addressing climate change should include three critical, interrelated elements: the environment, the economy and energy security.

Power generating facilities are a major source of CO_2 emissions in 2008, the facilities in our Midwest, West and Northeast segments emitted approximately 24.9 million, 5.2 million and 5.2 million tons of CO_2, respectively. The amounts of CO_2 emissions from our facilities during any time period will depend upon their dispatch rates during the period.

Recent court decisions and interpretations of the CAA by the U.S. EPA have added complexity to the national debate over the appropriate regulatory mechanisms for controlling and reducing CO_2 emissions. In April 2007, the U.S. Supreme Court issued its decision in *Massachusetts v. EPA*, involving the regulation of GHG emissions of motor vehicles. The Court ruled that GHGs meet the definition of a pollutant under the CAA and that regulation of GHG emissions is authorized by the CAA. The Court ruled that the U.S. EPA has a duty to determine whether or not GHG emissions may reasonably be anticipated to endanger public health or welfare within the meaning of the CAA. If the agency concludes that GHG emissions from new motor vehicles cause or contribute to a condition of air pollution that may reasonably be anticipated to endanger public health or welfare, then the agency would be required to set motor vehicle standards for GHG emissions. Regulation of GHG emissions from motor vehicles by the U.S. EPA following such a determination would likely lead to regulation of GHG emissions from stationary sources, such as power generating facilities, under other sections of the CAA. In response to the *Massachusetts v. EPA* decision, the U.S. EPA issued an ANPR in July 2008 discussing potential regulation of GHG emissions under the CAA. The ANPR discusses each section of the CAA that applies to stationary sources, such as power generating facilities, and the complexities associated with regulating GHG emissions under these existing statutory provisions, which were designed to address more localized environmental matters. The agency expressed the view that it is not desirable to regulate GHG emissions using a law designed for very different environmental challenges, and solicited comments from the public on whether or not well-designed legislation for establishing a GHG regulatory framework would be more appropriate than regulation under the CAA. The comment period on the ANPR closed in November 2008; no endangerment finding has yet been made by the U.S. EPA.

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On December 2, 2008, EAB issued its opinion in *In re: Deseret Power Electric Cooperative*, an appeal from the grant of a construction permit under the PSD program. The EAB held that the CAA does not dictate whether U.S. EPA must apply BACT for the control of CO_2 emissions in PSD permits. Moreover, the EAB ruled that U.S. EPA has discretion to interpret the CAA on this point, and it remanded the case to the U.S. EPA for reconsideration. On December 18, 2008, the U.S. EPA Administrator Johnson sent a memorandum (the Johnson Memorandum) to the agency s regional administrators setting forth the agency s interpretation that pollutants subject to PSD requirements exclude those pollutants for which EPA regulations only require monitoring and reporting of emissions, but include those pollutants subject to either a provision of the CAA or a regulation promulgated by the U.S. EPA under the CAA