DYNEGY INC /IL/
Form 10-K
March 14, 2005
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# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K

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

**For the fiscal year ended December 31, 2004**

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

**For the transition period from to**

**Commission file number: 1-15659**

# DYNEGY INC.

**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Illinois** | **74-2928353** |
| **(State or other jurisdiction of incorporation or organization)** | **(I.R.S. Employer Identification No.)** |

**1000 Louisiana, Suite 5800**

**Houston, Texas 77002**

**(Address of principal executive offices)**

**(Zip Code)**

**(713) 507-6400**

**(Registrant s telephone number, including area code)**

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

| Title of each class | Name of each exchange on which registered |
|---|---|
| **Class A common stock, no 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** | |

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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. 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 an accelerated filer (as defined in Rule 12b-2 of the Act). Yes x No ¨

The aggregate market value of the voting and non-voting equity held by non-affiliates of the registrant as of June 30, 2004, computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date, was $1,191,578,385, using the definition of beneficial ownership contained in Rule 13d-3 under the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers.

Number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date: Class A common stock, no par value per share, 283,759,437 shares outstanding as of March 4, 2005; Class B common stock, no par value per share, 96,891,014 shares outstanding as of March 4, 2005.

**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 2005 Annual Meeting of Shareholders, which will be filed not later than 120 days after December 31, 2004.

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**DYNEGY INC. FORM 10-K**

**INTRODUCTORY NOTE**

This Form 10-K reflects the effect of the following items on our historical consolidated financial statements and related information, as reported in Amendment No. 2 to our Annual Report of Form 10-K for the year ended December 31, 2003, which was filed on January 18, 2005:

- An increase of $16 million to the after-tax asset impairment charge of $120 million originally recorded in the fourth quarter 2003, associated with the sale of Illinois Power and

- A $45 million increase to our deferred tax liability at December 31, 2003, as well as increases to income tax expense in periods prior to 2004, related to errors in our previously completed tax basis balance sheet review.

Although neither of these items were considered material to the periods to which they related, these items, in aggregate, are material to our 2004 results. We are required to restate prior periods in accordance with APB 20, Accounting Changes. The items are discussed in more detail in the Explanatory Note to the accompanying consolidated financial statements beginning on page F-10. The following Items of our Form 10-K for the year ended December 31, 2003, as amended by Amendment No. 2, are affected by these items:

**Item 6.** ***Selected Financial Data***

**Item 7.** ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

**Item 8.** ***Financial Statements and Supplementary Data***

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**DYNEGY INC.**

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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 beginning on page F-86. Additionally, the terms Dynegy, we, us and our refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

### Item 1. *Business*

## THE COMPANY

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily in two areas of the energy industry: power generation and natural gas liquids.

During 2004, we made substantial progress toward the completion of our efforts to restructure our company to align more closely our asset base with our business strategy. Our significant accomplishments during this period include the sale of Illinois Power to Ameren for $2.3 billion, which reduced debt and preferred stock obligations by $1.8 billion, the replacement of our $1.1 billion credit facility with a new $1.3 billion credit facility, the restructuring of our Independence and Kendall tolling arrangements, the termination of four long-term natural gas transportation agreements, sales of non-core GEN and NGL assets generating approximately $260 million in proceeds and the pre-payment of the ABG Gas Supply financing and the ChevronTexaco junior notes.

We also continued our exit from the customer risk management business. Collateral to support our CRM business declined 22% from $121 million at the end of 2003 to $94 million at the end of 2004, primarily due to termination of the ABG Gas Supply contract. Our remaining customer risk management business, which primarily consists of our three remaining power tolling arrangements (including the Gregory toll, which expires in July 2005, but excluding the Independence toll, which is now part of our GEN segment) as well as our gas transportation agreements and legacy power and gas trading positions, will continue to impact negatively our cash flows and operating results until the associated obligations have been terminated, restructured or satisfied.

With only a few significant legacy matters remaining to be addressed, more of our company s resources are available to continue our efforts to operate our energy businesses safely, reliably and efficiently, to manage the costs across our organization and to deliver value to our investors. We are also continuing to focus on identifying and evaluating strategic growth opportunities, particularly organic or bolt-on projects, such as the conversion of our Havana power generating facility to lower-cost and lower-emission PRB coal, to improve the operational performance and efficiency of certain assets, enabling us to realize costs savings and to capture even more of the benefit of increases in commodity prices.

Such opportunities may also include merger and acquisition activities, which we discuss and evaluate as part of our ongoing business strategy. For example, in January 2005 we completed the purchase from Exelon Corporation of all of the outstanding capital stock of ExRes SHC, Inc., the parent company of Sithe Energies, Inc., which we refer to as Sithe Energies, and Sithe/Independence Power Partners, L.P., which we refer to as Independence. The financial terms of the acquisition included our payment of $135 million, subject to certain specified purchase price adjustments, and our consolidation of $919 million in face value project debt. Through this acquisition, we acquired the 1,021 MW combined-cycle Independence power generation facility located near Scriba, NY, four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. Independence holds power tolling, financial swap and other contracts with other of our subsidiaries. As a result of the acquisition, these contracts have become intercompany agreements and their financial statement impact will be substantially eliminated. This transaction both furthered our restructuring goal of addressing our outstanding power tolling arrangements, as well as enabled us to expand our generation capacity in a market where we have an existing presence.

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Dynegy began operations in 1985 and became incorporated in the state of Illinois in 1999 in anticipation of our February 2000 acquisition of Illinova Corporation. 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 and other information with the SEC. You may read and copy any document we file at the SEC s Public Reference Room at 450 Fifth Street, N.W., 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 website, 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.

## SEGMENT DISCUSSION

Our current business operations are focused primarily in two areas of the energy industry: power generation and natural gas liquids. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. As described below, our former regulated energy delivery business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation on September 30, 2004. We also separately report the results of our customer risk management business, which primarily consists of our three remaining power tolling arrangements (including the Gregory toll, which expires in July 2005, but excluding the Independence toll, which is part of our GEN segment for 2005) as well as our gas transportation contracts and legacy gas and power trading positions. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and infrastructure depreciation and amortization, but because of their nature, these items are not reported as a separate segment.

### Power Generation

***General.*** Our power generation segment is engaged in the production and sale of electric power from our owned and leased facilities. We sell power and related products and services, including capacity, into real-time and day-ahead markets, as well as on a forward basis. We seek to optimize our power generating assets and to mitigate our exposure to commodity prices through financial instruments and other transactions, including hedges related to our generation capacity and power purchases related to our supply obligations. Additionally, to mitigate risk related to fuel requirements at our generation facilities, we are also party to long-term coal purchase and transportation agreements and to short-term natural gas and fuel oil agreements.

We sell our power products and services under short- and long-term agreements. Short-term sales usually occur through industry standard contracts. Conversely, long-term sales usually occur under negotiated arrangements. Long-term contractual arrangements that we may enter into include:

- Sales of capacity purchased by customers to meet regulatory reserve requirements. Under these types of contracts, the purchasers may also acquire the option to purchase energy at an index or other pre-arranged price.

Tolling agreements under which we receive fixed payments in return for the customer s ability to purchase fuel for one of our facilities and take title to the power generated. Some contracts may also include provisions for reimbursement of variable operating and maintenance costs.

Ancillary services agreements under which we sell load regulation, scheduling services, reserves and voltage support to purchasers for fixed prices.

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Our customers include independent system operators (ISOs), municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, industrial customers, power marketers, other power generators and commercial end-users.

Additionally, markets exist for the purchase and sale of emission credits. From time to time, we either purchase emission credits from third parties in quantities sufficient to operate our plants within the emission guidelines of the various air districts or pay mitigation fees to the applicable air district as required. We may also sell emission credits that we do not need to utilize with respect to emissions from our generating facilities. Please read Regulation Power Generation Regulation beginning on page 21 and Environmental and Other Matters beginning on page 24 for further discussion of the environmental and regulatory restrictions applicable to our business.

***U.S. Generation Facilities***. We own or lease electric power generation facilities with an aggregate net generating capacity of 11,699 MWs located in six regions of the United States. The following table describes our current generation facilities by name, region, location, net capacity, fuel and dispatch type.

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**REGIONAL SUMMARY OF OUR U.S. GENERATION FACILITIES[1]**

**(as of December 31, 2004)**

| Region/Facility | Location | Total Net Generating Capacity (MWs) | Primary Fuel Type | Dispatch Type |
|---|---|---|---|---|
| Midwest-MAIN | | | | |
| Baldwin | Baldwin, IL | 1,768 | Coal | Baseload |
| Havana: | | | | |
| Havana Units 1-5 | Havana, IL | 238 | Oil | Peaking |
| Havana Unit 6 | Havana, IL | 445 | Coal | Baseload |
| Hennepin | Hennepin, IL | 290 | Coal | Baseload |
| Oglesby | Oglesby, IL | 54 | Gas | Peaking |
| Stallings | Stallings, IL | 82 | Gas | Peaking |
| Tilton | Tilton, IL | 176 | Gas | Peaking |
| Vermilion | Oakwood, IL | 191 | Coal/Gas/Oil | Baseload/ Peaking |
| Wood River: | | | | |
| Wood River Units 1-3 | Alton, IL | 130 | Gas | Peaking |
| Wood River Units 4-5 | Alton, IL | 452 | Coal | Baseload |
| Rocky Road (2) | East Dundee, IL | 165 | Gas | Peaking |
| Total Midwest-MAIN | | 3,991 | | |
| Midwest-ECAR | | | | |
| Riverside (6) | Louisa, KY | 495 | Gas | Peaking |
| Rolling Hills | Wilkesville, OH | 825 | Gas | Peaking |
| Foothills | Louisa, KY | 330 | Gas | Peaking |
| Renaissance | Carson City, MI | 660 | Gas | Peaking |
| Bluegrass | Oldham Co., KY | 495 | Gas | Peaking |
| Total Midwest-ECAR | | 2,805 | | |
| Northeast-NPCC | | | | |
| Roseton (3) | Newburgh, NY | 1,210 | Gas/Oil | Intermediate |
| Danskammer: | | | | |
| Danskammer Units 1 2 | Newburgh, NY | 128 | Gas/Oil | Peaking |
| Danskammer Units 3-4 (3) | Newburgh, NY | 370 | Coal/Gas/Oil | Baseload |
| Total Northeast-NPCC | | 1,708 | | |
| Southeast-SERC | | | | |
| Calcasieu | Sulphur, LA | 320 | Gas | Peaking |
| Heard County | Heard Co., GA | 495 | Gas | Peaking |
| Rockingham | Rockingham, NC | 825 | Gas/Oil | Peaking |
| Total Southeast-SERC | | 1,640 | | |
| West-WECC | | | | |
| Cabrillo I Encina (4) | Carlsbad, CA | 480 | Gas | Intermediate |

| | | | | |
|---|---|---|---|---|
| Black Mountain (5) | Las Vegas, NV | 43 | Gas | Baseload |
| El Segundo (4) | El Segundo, CA | 335 | Gas | Intermediate |
| Cabrillo II (4) | San Diego, CA | 87 | Gas | Peaking |
| Total West-WECC | | 945 | | |
| Texas-ERCOT | | | | |
| CoGen Lyondell | Houston, TX | 610 | Gas | Baseload |
| TOTAL | | 11,699 | | |

(1) We own 100% of each unit listed except as otherwise indicated. For each unit in which we own less than a 100% interest, the Total Net Generating Capacity set forth in this table includes only our proportionate share of such unit s gross generating capacity.

(2) We own a 50% interest in this facility and the remaining 50% interest is held by NRG Energy, Inc.

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(3) 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 Off-Balance Sheet Arrangements DNE Leveraged Lease beginning on page 45.

(4) We own a 50% interest in each of these facilities through West Coast Power, L.L.C., a joint venture with NRG Energy. Our 50% interest in West Coast Power s Long Beach generation facility has not been included because this asset was retired effective January 1, 2005 as discussed further below.

(5) We own a 50% interest in this facility and the remaining 50% interest is held by ChevronTexaco.

(6) We lease this facility.

***Midwest region Mid-America Interconnected Network (MAIN).*** At December 31, 2004, we owned nine generating facilities with an aggregate net generating capacity of 3,991 MWs located within MAIN. The generating capacity of our MAIN facilities represents approximately 6% of the generating capacity within the MAIN region. The MAIN market includes all of Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota and Michigan.

Approximately 50% of the power generated by our MAIN facilities was sold pursuant to a former power purchase agreement between DMG and Illinois Power which expired at the end of 2004. This agreement, which was served through Illinois Power s former generation facilities now owned by DMG, provided Illinois Power with approximately 70% of its capacity requirements through December 2004. The contract provided for fixed capacity payments based on the capacity reserved, as well as variable energy payments for each MWh of energy delivered under the contract based on DMG s cost of generation. Under the former agreement, DMG served as the provider of last resort to Illinois Power, providing the resources through which Illinois Power fulfilled its load obligations; it also supplied all ancillary services required by Illinois Power. This power purchase agreement provided a substantial portion of the operating income from our power generation business in 2004.

In connection with our sale of Illinois Power to Ameren in the third quarter 2004, we entered into a new contract to sell to Illinois Power 2,800 MWs of capacity at $48 per KW-yr and up to 11.5 million MWh of energy at a fixed price of $30 per MWh to Illinois Power for two years beginning in January 2005. We also agreed to sell 300 MWs of capacity in 2005 and 150 MWs of capacity in 2006 to Illinois Power at a fixed price of $16 per KW-yr with an option to purchase energy at market-based prices. Under this arrangement, we no longer are the provider of last resort to Illinois Power. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations 2005 Outlook GEN Outlook beginning on page 67 for further discussion.

Approximately 9% of our total capacity in this region which is not committed under the Illinois Power power purchase agreement will be sold under capacity contracts in 2005, including 165 MWs related to our interest in Rocky Road through 2009. The remainder of the capacity and energy is sold primarily into wholesale markets in MAIN, the neighboring East Central Reliability, or ECAR, and the Pennsylvania-New Jersey-Maryland market, or PJM.

All of our MAIN facilities (except Rocky Road, which is located in PJM) are located in a market to be administered by the Midwest ISO Regional Transmission Organization, or MISO. Formation of MISO was approved by the FERC in 2001, and MISO currently administers transmission operations. MISO has received FERC approval to begin operating energy markets on April 1, 2005. MISO has indicated that it plans to use locational-pricing for energy, as well as financial transmission rights to allow market participants to manage transmission risks. MISO has proposed implementation of a capacity market by June 1, 2006, but has not yet committed to a specific market design. The impact on our results of operations, financial condition and cash flows of MISO capacity market structures, should they be implemented, cannot currently be estimated.

The MAIN region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2004 reserve margin of 30%. MISO proposals to implement

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reserve requirements and capacity markets are currently under development, but we expect reserve margin targets will generally be consistent with the 15% target reserve margin of Pennsylvania-New Jersey-Maryland Interconnection, LLC, or PJM. Overcapacity in the MAIN region has depressed energy and capacity prices and likely will continue to do so absent peak demand growth and/or plant retirements. Based on current expectations of future demand growth and retirements, we believe that reserve margins are likely to return to target levels within the next 3-5 years.

***Midwest region East Central Area Reliability Council (ECAR).*** We own or lease interests in five generating facilities with an aggregate net generating capacity of 2,805 MWs located within ECAR. The majority of the power generated by our ECAR facilities is sold to wholesale customers in the ECAR market, which includes all or portions of the states of Indiana, Ohio, Michigan, Virginia, West Virginia, Tennessee, Kentucky, Maryland and Pennsylvania.

At the end of 2003, we entered into a contract for 495 MWs of our Renaissance facility s generating capacity, which expired in September 2004. In July 2004, we entered into an agreement with a term from June 2005 through May 2006 to sell 500 MWs of capacity from our peaking facilities in the ECAR region. In August 2004, we entered into an additional agreement with a term from May 2005 through September 2005 to sell 330 MWs of our Renaissance facility s net generating capacity. The generating capacity of our ECAR facilities represents approximately 2% of the generating capacity within the region.

Our Renaissance and Bluegrass facilities are located in the MISO. Our Riverside, Rolling Hills, and Foothills facilities are located within PJM. PJM s geographic area has significantly expanded in the past two years, including the addition of the AEP service area in which the Riverside, Rolling Hills, and Foothills facilities are located. The boards of PJM and MISO have committed to establish a joint and common market across their respective regions; however, there can be no assurance that efforts to integrate the two market structures will be successful.

PJM currently administers markets for wholesale electricity and provides transmission planning for the region. PJM operates day-ahead and real time markets into which generators can bid to provide electricity and ancillary services. To account for transmission congestion and losses, PJM calculates prices using a locational-based pricing model that is also used to determine generation unit dispatch. Wholesale electricity prices in PJM are currently capped at $1,000 per MWh. PJM also administers markets for installed capacity, which are an important potential revenue source for peaking facilities. PJM has proposed changes to its capacity markets, including establishing longer-term markets for capacity to improve market signals for new generation, although there are no assurances that such proposals will be implemented. The future economic impact, if any, of PJM and MISO policies and proposals on our ECAR facilities cannot currently be estimated.

The ECAR region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2004 reserve margin of 27%. MISO has indicated that it will enforce the current reserve requirement in each Reliability Region (i.e., MAIN, ECAR and MAPP) until such time that a capacity market is implemented. The reserve requirement to apply during the period following establishment of such capacity market has not been determined. This overcapacity has depressed energy and capacity values in this region and likely will continue to do so absent peak demand growth and/or plant retirements. Based on current expectations of future demand growth and retirements, we believe that reserve margins are likely to return to target levels within the next 3-5 years.

***Northeast region Northeast Power Coordinating Council (NPCC).*** We lease two generating facilities in New York, which we refer to as the DNE facilities, with an aggregate net generating capacity of 1,708 MWs. Our DNE facilities sites are adjacent and share common resources such as fuel handling, a docking terminal, personnel and systems. The generating capacity of these facilities represents approximately 5% of the generating capacity in the state of New York.

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On January 31, 2005, we acquired from Exelon Corporation the 1,021 MW Independence power generating facility in New York. Prior to this acquisition, we were entitled to 955 MW of the power generated by this facility under the Independence tolling arrangement. The toll remained in effect and was transformed into an intercompany obligation under our GEN segment. Additionally, we acquired four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. Approximately 72% of the Independence facility s capacity is obligated under a capacity sales agreement, which runs through 2014. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion of this acquisition.

The New York Independent System Operator, or NYISO, administers the statewide transmission system and spot markets for electricity and, like PJM, calculates electricity prices and dispatches generation using a locational-based pricing model. NYISO also administers markets for installed capacity, operating reserves and regulation service. NYISO employs an AMP in its day-ahead electricity market that caps energy bids when certain bid screen criteria are exceeded. In 2003, NYISO implemented a Demand Curve mechanism for calculating pricing for installed capacity for three locational zones: New York City, Long Island, and the rest of the State of New York. Our facilities operate outside of New York City and Long Island. Capacity pricing is calculated as a function of NYISO s 18% target reserve margin, estimated cost of new entrant generation, estimated peak demand, and the actual amount of capacity bid into the market. 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 target levels.

Due to transmission constraints, prices vary across the state 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 of 21% are somewhat above the NYISO s target reserve margin of 18%. We believe that reserve margins are likely to return to target levels within the next 3-5 years.

***Southeast region Southeastern Electric Reliability Council (SERC).*** We own interests in three generating facilities with an aggregate net generating capacity of 1,640 MWs located within SERC. SERC includes all or portions of the states of Missouri, Kentucky, Arkansas, Tennessee, West Virginia, Virginia, North Carolina, South Carolina, Louisiana, Mississippi, Alabama and Georgia. The generating capacity of these facilities represents approximately 1% of the generating capacity in SERC. Of our 1,640 MWs of net generating capacity in SERC, 665 MWs, or 40%, is sold under contract. A contract for our Calcasieu facility s 320 MWs of capacity expired in December 2004. In January and February 2004, we signed two agreements to sell an aggregate 215 MWs of our Rockingham facility s net generation capacity, with terms beginning in 2006 and expiring in 2010. We also signed an agreement in January 2004 covering an additional 165 MWs of our Rockingham facility s net generating capacity, which expired in September 2004.

Our SERC assets are located within the control areas of vertically integrated utilities and municipalities. All power sales and purchases are consummated between individual parties and are physically delivered either within or across the control areas of the transmission owners. The present market framework in SERC is not a centralized market, and the timing of any transition to centralized competitive markets for energy and capacity is currently unknown.

The SERC region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2004 reserve margin of 51%, which significantly exceeds SERC s estimated target reserve margin of approximately 17%. This overcapacity has depressed energy and capacity values in this region and likely will continue to do so absent peak demand growth and/or plant retirements. Overcapacity is concentrated in the Entergy and Southern sub-regions of SERC, and these regions are unlikely to see reserve margins near target levels within the next ten years. Overcapacity is less severe in the VACAR sub-region of SERC, where we believe market conditions may require new capacity additions within the next 4-6 years.

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***West region Western Electricity Coordinating Council (WECC).*** We own interests in four generating facilities with an aggregate net generating capacity of 945 MWs within WECC. The WECC regional market includes all or parts of the states of Arizona, California, Oregon, Nevada, New Mexico, Colorado, Wyoming, Idaho, Montana, Nebraska, Texas, South Dakota, Utah and Washington. Our generating capacity in the WECC represents less than 1% of the overall generating capacity in this region.

Of our 945 MWs of net generating capacity in the WECC, 902 MWs consists of our 50% share of the 1,804 MWs of facilities owned by West Coast Power. All of the West Coast Power facilities are located in southern California, and the generation output of the facilities was substantially covered by a contract, which we refer to as the CDWR contract, between one of our marketing subsidiaries, as agent for the facility owners, and the CDWR. This contract expired in December 2004.

Since the expiration of the CDWR contract, all of our West Coast Power assets have been operating under Reliability Must Run (RMR) Condition II contracts with the Cal ISO, except for the Long Beach facility, which is discussed below. Under the terms of these RMR contracts, Cal ISO reimburses West Coast Power for 100% of approved costs plus a rate of return specified in the contracts. When the facilities are instructed to provide power by the Cal ISO, they are reimbursed for their variable production costs. Under RMR Condition II, the facilities are 100% committed to the Cal ISO and, therefore, do not experience changes in market conditions through bilateral energy or capacity sales to third parties that might otherwise be consummated. The RMR contracts are effective for calendar year 2005. The Cal ISO may renew or terminate the RMR contracts at its sole option on an annual basis as of the first of the following year. In addition West Coast Power, through one of our marketing subsidiaries, as agent for the facility owner, has entered into a power sales agreement with a major California utility for the sale of 100% of the capacity and associated energy from the El Segundo facility from May through December 2005. During the term of this agreement, the purchaser will be entitled to primary energy dispatch rights for the facility s generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO s ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary.

In California s current energy market, the West Coast Power generating facilities are significantly less profitable under RMR contracts or as merchant facilities, and we may consider other alternatives if necessary, including shutting down units if we no longer consider them commercially viable. Based on our ongoing evaluation of strategic alternatives for our West Coast Power assets, we determined that it was not economically feasible to continue to operate our Long Beach generation facility beyond the expiration of the CDWR contract. Therefore, we retired the asset as of January 1, 2005.

Our West Coast Power facilities are located in the Cal ISO control area, which includes facilities serving approximately 75% of California s demand. The Cal ISO schedules transmission transactions, arranges for ancillary services, and administers a real time balancing energy market. Day ahead purchases and sales are executed bilaterally and scheduled for physical delivery by the Cal ISO. There is currently no capacity market in the Cal ISO. The Cal ISO is continuing its plan to move toward a market design similar to PJM and NYISO, although the timing and final structure of any such market design cannot currently be predicted.

For a discussion of litigation and other legal proceedings related to energy market restructuring in California, the impact of current regulations on our WECC facilities and related uncertainty associated with the California wholesale market, please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings California Market Litigation beginning on page F-58.

***Texas region Electric Reliability Council of Texas (ERCOT).*** We own a generating facility with a generating capacity of 610 MWs located in ERCOT. This facility represents less than 1% of the generating capacity in the ERCOT region. The ERCOT market is comprised of the majority of the state of Texas.

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Approximately 13% of our capacity in this region, consisting of 80 MWs of capacity at our CoGen Lyondell facility, is sold under a capacity agreement which expires in December 2006.

Our Texas facility participates in a market administered by the ERCOT ISO, which oversees competitive wholesale and retail markets. ERCOT s operations are overseen by the PUCT. ERCOT operates as the single control area within its region, and operates capacity and energy markets for market participants. Price mitigation measures in ERCOT include a $1,000 per MWh offer cap. ERCOT is considering wholesale market design changes including locational-based pricing similar to markets in NYISO and PJM in response to a PUCT rule; however, there can be no assurances that such design changes will be implemented.

By most measures, the ERCOT region currently has excess generation capacity as a result of recent development projects. This overcapacity is evidenced by the NERC s estimated 2004 reserve margin of 26%, which is significantly in excess of the ERCOT s target minimum reserve margin of 12.5%. This overcapacity has depressed energy and capacity values in this region and will likely continue to do so absent peak demand growth and/or plant retirements. However, recently released reports from ERCOT indicate that reserve margins may fall below the 12.5% level within the next 1 2 years due to recently announced generating retirements and mothballed units.

***International.*** In addition to our U.S. generating assets, as of December 31, 2004, we owned a 50% interest in a generating facility located in Panama. Upon expiration of a capacity contract in January 2005, this facility is operating on a merchant basis. We are continuing to pursue opportunities to sell our interest in this facility Panama project, as we do not consider it core to our power generation business. Our 18% interest in a 74 MW generation asset in Jamaica was sold in January 2004 for $5.5 million.

***Retail Supply Business.*** We selectively enter into short- and long-term contracts with individual commercial and industrial customers to serve their load requirements in markets where we have a generation presence and where the regulatory environment supports these efforts. Our current sales and retail operations are directed toward Texas, Illinois and New York. In early 2005, we made the decision to formally exit the Retail Supply Business.

**Natural Gas Liquids**

***General***. Our natural gas liquids segment consists of our midstream asset operations, located principally in Texas, Louisiana and New Mexico, and our North American natural gas liquids marketing business. This segment has both upstream and downstream components. The upstream components include natural gas gathering and processing; while the downstream components include fractionating, storing, terminalling, transporting, distributing and marketing natural gas liquids.

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The following graphic depicts the revenue opportunities that exist throughout our upstream and downstream operations.

***Upstream Business***

Our upstream business includes the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting natural gas liquids and removing impurities. We own interests in 17 gas processing plants, including 11 plants we operate. We also operate over 9,385 miles of natural gas gathering pipeline systems associated with the 11 operated facilities and two stand-alone natural gas gathering pipeline systems where gas is treated and/or processed at third-party plants. Our upstream assets are located in the growing oil and gas exploration and production areas of North Texas and Louisiana, and the mature Permian Basin of West Texas and Southeast New Mexico. During 2004, we processed an average of 1.6 Bcf/d of natural gas and produced an average of 82,120 barrels per day of natural gas liquids, in each case, net to our ownership interests. We are also party to natural gas processing agreements with five third-party plants.

Our upstream business is significantly impacted by the types of contracts under which we process gas. There are four primary types of gas processing contracts where natural gas liquids are extracted: percent of proceeds, percent of liquids, keep-whole and wellhead purchase.

Under percent of proceeds, or POP, contracts, a producer delivers to us a percentage of the natural gas liquids and a percentage of the natural gas as payment for our services and retains the value of the remaining natural gas liquids and natural gas at the processing plant tailgate. The producer retains this value by either taking its share of the natural gas liquids and natural gas in kind or by receiving its share of the proceeds from our sale of their share of the commodities.

Under percent of liquids, or POL, contracts, a producer delivers to us a percentage of the natural gas liquids as payment for our services and retains the value of the remaining natural gas liquids and all of the natural gas at the processing plant tailgate. Similar to POP contracts, the producer will either take their share of the natural gas liquids in kind or take the proceeds from our sale of their share of the natural gas liquids.

Under keep-whole, or KW, contracts, we extract natural gas liquids and return to the producer volumes of merchantable natural gas containing the same Btu content as the unprocessed natural gas that was delivered to us. We retain the natural gas liquids as our payment for processing. We must purchase and return to the producer sufficient volumes of merchantable natural gas to replace the Btus that were removed as natural gas liquids through processing so that the producer is kept whole on a Btu basis. This contract type is fully exposed to the frac spread, which is the relative difference in value between natural gas liquids and natural gas on a Btu basis.

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Under wellhead purchase, or WHP, contracts, we purchase unprocessed natural gas from a producer at the wellhead at a discount to the market value of the gas. This discount, together with any value increase for natural gas liquids extracted from the natural gas, is our margin for gathering and processing.

Factors influencing the contract mix at a particular facility include, among other things, the Btu content of the gas, which determines if natural gas liquids must be extracted from the natural gas to meet natural gas pipeline quality specifications; the investment in extensive gathering systems to bring gas to a particular plant; the term of the gas supply contracts behind a processing plant; and the prevailing competitive factors when contracts are negotiated.

We characterize our natural gas processing plants in two categories  field plants and straddle plants. The processing contract mix varies significantly between the two categories.

***Field Plants.*** Field plants connect volumes of unprocessed gas from multiple onshore producing wells. Through extensive gathering systems, these volumes are aggregated into sufficient volumes to be economically processed to extract natural gas liquids and to remove water vapor, solids and other contaminants to provide marketable natural gas, commonly referred to in the industry as  residue gas.  The following map depicts our field plant assets, including our capacity, 2004 natural gas throughput and natural gas liquids production levels for the assets as of year end 2004. Our field plants are located in the mature and prolific Permian Basin of West Texas and Southeast New Mexico, and in North Texas, where we are ideally situated to benefit from the high volume growth Barnett Shale production development.

In our field plants we process natural gas primarily under POP contracts. In 2004, approximately 99% of the volumes processed were under POP settlement terms and the remainder was processed under KW or WHP contracts. We expect a similar contract mix in 2005. This is particularly important because the natural gas processed by all of these facilities contains natural gas liquids in sufficient quantities to require that the natural gas be processed to extract enough of the natural gas liquids to meet gas pipeline and market quality specifications. Having essentially all POP contracts removes the significant price spread risk associated with KW and WHP contracts and makes the key economic drivers for our field plants natural gas and natural gas liquids volumes and the absolute price of both residue gas and natural gas liquids.

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Our field plants recovered an average of 4.28 gallons of natural gas liquids per Mcf of raw gas processed in 2004. The component split of mixed natural gas liquids produced by our field plants in 2004 was as follows:

We are also impacted by producer drilling activity, which is sensitive to commodity prices. Additionally, safe, low-cost and reliable operation of our facilities, together with highly efficient plant operation, improves our competitiveness in attracting new gas volumes to replace intrinsic declines in natural gas well production at the same or better contractual terms.

***Straddle Plants.*** Straddle plants generally are situated on mainline natural gas pipelines. Our straddle plants are located on pipelines transporting natural gas from the Gulf of Mexico to key Midwest and East Coast natural gas markets. The following map depicts our straddle plant assets as of year end 2004, including our capacity, 2004 natural gas throughput and natural gas liquids production levels.

We process natural gas in our straddle plants under POL and KW contracts as well as hybrid contracts that contain different settlement terms. Under hybrid contracts, the settlement outcome can be either POL, KW or a fee and is usually triggered by market conditions, most often automatically, or, in some cases, by the election of one or both of the parties. When it is economical to extract natural gas liquids, these hybrid contracts typically settle under POL terms.

When it is not profitable to extract natural gas liquids (i.e., when the value of the natural gas liquids is less than the value of natural gas on an equivalent Btu basis), most of the volumes processed under these hybrid

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contracts automatically convert to a fee-based processing arrangement. This fee is generally paid in the form of cash and/or a nominal percentage of the natural gas liquids processed. For some of these volumes, the producer and/or the processor have contract settlement election options. The producer can elect to either process or not process, generally on a POL basis. If the producer elects to not process, we often have the option to process on a KW basis. If we elect to not process, either we can cause the gas to bypass the plant, where such capabilities exist, or the producer pays us a per-unit fee to process the gas.

The charts below show the current and expected contract mix for our straddle plants. On the left, the current mix does not reflect an expected FERC approval of hydrocarbon dew point specifications on natural gas pipelines along the Gulf of Mexico. Assuming FERC approves hydrocarbon dew point specifications, significant production historically processed under KW contracts will be generally settled under fee or hybrid contracts. The chart on the right shows our anticipated contract mix following enforcement of hydrocarbon dew point specifications on pipelines in the Gulf area and reflects our expectation of a significant decline in our frac spread exposure.

The results of our straddle plant operations are heavily dependent on the absolute price of natural gas liquids. This is particularly true when processing economics are favorable, as the hybrid contracts settle under POL terms. When processing economics are less favorable, we do have some KW exposure to the frac spread. Our view is that strong natural gas prices will generally continue to depress the frac spread for the foreseeable future. However, our frac spread exposure is limited because most of the hybrid contracts in this price environment settle on fee terms.

As with our field plants, our straddle plants are impacted by producer drilling activity, which is sensitive to commodity prices, as well as our ability to operate safely, reliably and efficiently.

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The straddle plants recovered an average of 1.13 gallons of natural gas liquids per Mcf of raw gas processed in 2004. The component split of mixed natural gas liquids produced by our straddle plants in 2004 was as follows:

Major customers of our upstream business include ChevronTexaco and many other large and small producers. We have a contractual right to process substantially all of ChevronTexaco s gas in North America. Generally, with respect to gas they produce from all areas other than the Gulf of Mexico, we process the gas at field plants owned by us or by third parties. The ChevronTexaco gas processed in our field plants is processed on a POP basis and is based on ChevronTexaco s commitment of such production for the life of the lease from which the production is obtained.

With respect to the gas produced from the Gulf of Mexico area, ChevronTexaco s gas is processed in both straddle plants in which we own an interest and in plants owned by third parties. We operate five of the plants in which we own an interest. ChevronTexaco gas produced from the Gulf of Mexico area is processed on a POL basis when processing is economical or is processed on a fee basis if natural gas liquids extraction is not profitable. The leases, or portions thereof, committed under this agreement are committed for the life of the leases dedicated to us for processing. Until September 1, 2006, ChevronTexaco has agreed to dedicate to us for processing any gas attributable to new production obtained from oil, gas and/or mineral leases not previously dedicated to us for processing as of March 1, 2002. These dedications made by ChevronTexaco may be limited to certain productive horizons and/or may only be partially committed as to acreage.

Both types of processing agreements with ChevronTexaco allow either party to initiate renegotiation of the commercial terms for processing previously dedicated natural gas production effective in September 2006 and on each successive 10-year anniversary thereafter for ChevronTexaco gas processed in field plants; and, five years thereafter, for gas produced from the Gulf of Mexico and processed in Louisiana straddle plants. During 2004 and 2003, respectively, ChevronTexaco gas accounted for 32% and 46% of the total volume of gas we processed.

***Hedging Strategy.*** As a result of our POP and POL contracts, we take ownership of natural gas and natural gas liquids as payment for our services. We have a comprehensive hedging strategy and related control procedures to manage price risk on these equity volumes. We limit volume considered for hedging and forward selling to Dynegy-owned volumes received at our field processing facilities that must operate for gas to meet natural gas pipeline quality specifications. The portion of equity natural gas and natural gas liquids that we hedge is monitored closely against our field processing plant operations to ensure we hedge no more than the volume we own. We seek to mitigate correlation risk by hedging each natural gas liquid product against our physical production of that product. Realized loss on hedged volumes was $10 million below the average realized price for unhedged volumes for 2004 as compared to $7 million below the average realized price for unhedged volumes for 2003.

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***Downstream Business***

In our downstream business, we use our integrated assets to fractionate, store, terminal, transport, distribute and market natural gas liquids. Our downstream assets are generally connected to and supplied, in part, by our upstream assets and are located in Mont Belvieu, Texas, the hub of the U.S. natural gas liquids business, and West Louisiana. The following map depicts our downstream assets, including our capacity and throughput capabilities.

***Fractionation***. When pipeline-quality natural gas is separated from natural gas liquids at processing plants, the natural gas liquids are generally in the form of a commingled stream of light liquid hydrocarbons, which is referred to as mixed or raw natural gas liquids. The mixed natural gas liquids are separated at fractionation facilities through a distillation process into the following component products:

- Ethane, or a mixture of ethane and propane known as EP mix;
- Propane;
- Normal butane;
- Isobutane; and
- Natural gasoline.

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The percentages of these products produced at our fractionators in 2004 were as follows:

We fractionate volumes for customers, from both our own upstream operations and third parties, under contracts that typically include a base fee per gallon plus other fee components that are subject to adjustment for variable costs such as energy consumed in fractionation. We have ownership interests in three stand-alone fractionation facilities that are strategically located on the Texas and Louisiana Gulf Coast. We operate two of the facilities, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. During 2004, these facilities fractionated an aggregate average of 183,000 gross barrels per day (net to Dynegy s ownership interests). We also have an equity investment in a third fractionator located in Mont Belvieu, which is subject to a 1996 consent decree with the FTC that prevents us from participating in commercial decisions regarding rates paid by third parties for fractionation services.

The results of our fractionation operations are significantly impacted by the following factors: our ability to attract term volumes of raw natural gas liquids at profitable margins; the impact of frac spreads on the supply of natural gas liquids available for fractionation; the composition of the liquids received; energy costs; and operational efficiencies.

***Storage & Terminalling.*** Our natural gas liquids storage facilities have extensive pipeline connections to third-party pipelines, third-party facilities and to our own fractionation and terminalling facilities. In addition, some of these storage facilities are connected to marine, rail and truck loading and unloading facilities that provide service and products to our customers. We provide long- and short-term storage services and throughput capability to affiliates and third-party domestic customers for a fee.

We own and/or operate a total of 41 storage wells with an aggregate capacity of 108 MMBbls, the usage of which may be limited by brine handling capacity. Brine is utilized to displace natural gas liquids from storage. When large volumes of natural gas liquids are stored, we store the displaced brine in our brine storage ponds adjacent to our storage facilities and, depending on the volume, may inject excess brine in our brine disposal wells. When reduced volumes of natural gas liquids are stored, we utilize the brine from our brine storage ponds to displace the volumes of natural gas liquids removed and, if necessary, can produce additional brine from wells dedicated for that purpose through a process known as brine leaching.

The results of our storage operations are significantly impacted by the following factors: the petrochemical industry s level of capacity utilization and their specific feedstock requirements; our ability to utilize our integrated asset base flexibly to meet changing customer and market demands; and safe, low-cost, efficient operations.

***Transportation and Logistics.*** Our natural gas liquids transportation and logistics infrastructure comprises a wide range of transportation and distribution assets supporting both third-party customers and the delivery requirements of our distribution and marketing business. We provide a fee-based transportation service to refineries and petrochemical companies throughout the Gulf Coast area. These assets are also deployed to serve our wholesale distribution terminals, fractionation facilities, underground storage facilities, pipeline injection terminals and many of the nation s crude oil refineries and petrochemical facilities. Our marine terminals are

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located in Texas, Florida, Louisiana and Mississippi. We also have wholesale propane terminals located in Tennessee, Texas, Mississippi, Kentucky and Florida, and lease capacity at third-party storage facilities throughout North America. These distribution assets provide a variety of ways to transport and deliver products to our customers. Our transportation assets include:

- More than 2,000 railcars owned or leased by ChevronTexaco that we manage pursuant to a services agreement with ChevronTexaco;
- 78 transport tractors and 114 tank trailers;
- More than 550 miles of gas liquids pipelines, primarily in the Gulf Coast area; and
- 21 natural gas liquids pressurized barges with more than 320,000 barrels of capacity.

***Distribution and Marketing Services***. Our distribution and marketing services include: (1) Refinery services; (2) Wholesale propane marketing; and (3) Purchasing mixed natural gas liquids and natural gas liquids products from natural gas liquids producers and other sources and selling the natural gas liquids products to petrochemical manufacturers, refineries and other marketing and retail companies.

- ***Refinery Services.*** In our refinery services business, we provide LPG balancing services, purchasing natural gas liquids products from refinery customers and selling natural gas liquids products to various customers. We also use our storage, transportation, distribution and marketing assets to assist refinery customers in managing their natural gas liquids product demand and production schedules. This includes both feedstocks consumed in refinery processes and the excess LPG produced by those same refining processes. Under our netback contracts, we generally retain a portion of the resale price of natural gas liquids sold or receive a fixed minimum fee per gallon on products sold. Also under netback contracts, fees are obtained for locating and supplying natural gas liquids feedstocks to the refineries either based on a percentage of the cost to obtain such supply or through a minimum fee per gallon. In 2004, we sold an average of 38,000 barrels of LPG per day through our refinery services business.

We have refinery services contracts with each of ChevronTexaco s refineries situated in El Segundo, California; Pascagoula, Mississippi; Richmond, California; Salt Lake City, Utah; and Barbers Point, Hawaii. All of these contracts allow us to market excess LPG produced during the refining process. With respect to all of the ChevronTexaco refineries, except Hawaii, these agreements also require us to supply to ChevronTexaco natural gas liquids utilized in their refining process as required by the refinery. The agreements require us to obtain, on behalf of the refineries, natural gas liquids feedstocks that each refinery requires on a daily basis. These agreements extend through August 2006. Approximately 47% and 44% of the business natural gas liquids volumes purchased in 2004 and 2003, respectively, were from ChevronTexaco.

Key factors impacting the results of our refinery services business include propane and butane prices, our ability to perform receipt, delivery and transportation services and refinery demand.

- ***Wholesale Propane Marketing.*** Our wholesale propane marketing operations include the sale of propane and related logistics services to major multi-state retailers, independent retailers and other end users. Our propane supply primarily originates from both our refinery/gas supply contracts and our other owned and/or managed distribution and marketing assets. We generally sell propane at a fixed or posted price at the time of delivery. In 2004, we sold an average of 44,500 barrels of propane per day.

Our wholesale propane marketing business is significantly impacted by weather-driven demand, particularly in the winter, the price of propane in the markets we serve and our ability to deliver propane to customers to satisfy peak winter demand.

***Distribution and Marketing Services.*** We market our own natural gas liquids production and also purchase natural gas liquid products from other natural gas liquids producers and marketers for resale. In 2004, our distribution and marketing services business sold an average of 200,000 barrels per day of natural gas liquids in North America. We generally purchase mixed natural gas liquids from producers

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at a monthly pricing index less applicable fractionation, transportation and marketing fees and resell these products to petrochemical manufacturers, refineries and other marketing and retail companies. This is primarily a physical business in which we earn margins from purchasing and selling natural gas liquid products from producers under contract. We also earn margins by purchasing and reselling natural gas liquids products in the spot and forward physical markets.

We also have the right to purchase or market substantially all of ChevronTexaco s natural gas liquids pursuant to a Master Natural Gas Liquids Purchase Agreement that extends through August 31, 2006.

This business is impacted by a number of factors, including our ability to prudently manage inventories during periods of market price movements and meeting our delivery obligations under term contracts.

In 2004 and 2003, approximately 35% and 32%, respectively, of our specification natural gas liquids sales were made to ChevronTexaco or one of its affiliates pursuant to the refinery agreements discussed above and pursuant to an agreement we have with Chevron Phillips Chemical Company. In the latter agreement, we supply a significant portion of Chevron Phillips Chemical s natural gas liquids feedstock needs in the Mont Belvieu area and collect a cents-per-barrel fee for storage and product delivery.

**Regulated Energy Delivery**

***General.*** Our regulated energy delivery segment consisted of our former Illinois Power Company subsidiary, which we sold in September 2004. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23 for further discussion. Illinois Power is a regulated public utility based in Decatur, Illinois, and is engaged in the transmission, distribution and sale of electric energy and the distribution, transportation and sale of natural gas in the state of Illinois. Illinois Power provides retail electric and natural gas service to residential, commercial and industrial consumers in substantial portions of northern, central and southern Illinois. Illinois Power also currently supplies electric transmission service to electric cooperatives, municipalities and power marketing entities in the state of Illinois.

From February 1, 2002 through July 31, 2002, this segment also included the results of Northern Natural. We acquired Northern Natural from Enron Corp. in connection with our terminated merger and subsequently sold Northern Natural to MidAmerican Energy Holdings Company in August 2002. Northern Natural is accounted for as a discontinued operation in the accompanying financial statements. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Northern Natural beginning on page F-27 for further discussion.

**Customer Risk Management**

Our CRM segment is comprised largely of our three remaining power tolling arrangements (including the Gregory toll, which expires in July 2005, but excluding the Independence toll). Upon the closing of our Sithe Energies acquisition in January 2005, the Independence tolling arrangement was transformed into an intercompany obligation under our GEN segment, which now includes the Independence facility. In addition, we have mitigated the effect of our Kendall tolling arrangement through November 2008 by entering into a back-to-back power purchase agreement with a subsidiary of Constellation Energy, whereby we will receive payments which offset our obligations to LSP-Kendall.

Pursuant to these power tolling arrangements, we are obligated to make aggregate payments of approximately $1.3 billion to our counterparties in exchange for access to power generated by their facilities, resulting in a total obligation of $1.2 billion, net of $161 million to be received from Constellation. In addition to these tolling arrangements, our CRM segment includes gas transportation contracts and our remaining gas and power trading positions. We are actively pursuing opportunities to terminate, assign or renegotiate the terms of our contractual obligations related to our remaining obligations under these agreements.

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The following table contains a listing of our power tolling arrangements, including the name and location of each related project, the term of each arrangement, the project capacity and our annual capacity payments, as well as other CRM fixed obligations.

**CRM Obligations**

| Project | Location | Expiration Date | MWs | Annual Capacity Payments 2005 | 2006 | 2007 | 2008 2017 |
|---|---|---|---|---|---|---|---|
| | | | | | (in millions) | | |
| Sterlington/Quachita | Louisiana | 9/2017(1) | 835 | $ 59 | $ 61 | $ 63 | $ 627 |
| Gregory | Texas | 7/2005 | 335 | 13 | | | |
| Kendall | Illinois | 3/2017(1)(2) | 578 | 39 | 41 | 42 | 374 |
| Independence | New York | 11/2014(3) | 955 | 4 | | | |
| Total annual capacity payments | | | | 115 | 102 | 105 | 1,001 |
| Other fixed obligations | | | | 8 | 2 | 2 | |
| Less: Payments to be received from Constellation (2) | | | | (39) | (41) | (42) | (39) |
| Net cash commitments | | | | $ 84 | $ 63 | $ 65 | $ 962 |

(1) Includes a five-year extension option pursuant to which either party can elect to continue the arrangement depending on the market price for power at the expiration of the initial contract term.
(2) We have entered into an offsetting agreement with a subsidiary of Constellation Energy through November 2008, under which we will receive payments equal to those owed under our Kendall tolling arrangement.
(3) On January 31, 2005, we completed the Sithe Energies acquisition, which resulted in the transformation of our obligations under the Independence tolling arrangement and related derivative instrument into intercompany obligations under our GEN segment.

Regarding our legacy gas and power trading positions, we have substantially reduced the size of our mark-to-market portfolio since October 2002, when we initiated our efforts to exit the CRM business. As of December 31, 2004, we have exited approximately 90% of our physical and financial gas business. We expect to have effectively exited this business by the end of 2007, with the exception of a minimal number of physical gas transactions that expire between 2010 and 2017. Additionally, we have forward obligations to deliver emissions allowances. Currently, we own adequate allowances to satisfy the forward obligations. Our remaining CRM power business, exclusive of our power tolling arrangements, will be effectively exited by the end of 2005; with the exception of a minimum number of positions that will remain until 2010. We will continue our efforts to exit the remaining transactions as allowed by market liquidity and credit requirements.

**Other**

Our Other results include 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 technology. Corporate general and administrative expenses, income taxes and corporate interest expenses, which we previously allocated among our operating divisions, are included in our other reported results, as are corporate-related other income and expense items. Interest expense associated with borrowings incurred by our operating divisions, such as our power generation facility financings, will continue to be reflected in the appropriate business segment s results. Other results for the periods presented also include our discontinued global communications business.

The communications business was established during the fourth quarter 2000 and included an optically switched, mesh fiber-optic network with more than 16,000 route miles that reached 44 cities in the United States. During the first quarter 2003, we sold our European communications business, which operated a high-capacity, broadband network with access points in 32 cities throughout Western Europe. During the second quarter 2003, we sold our U.S. communications business. Since we have substantially completed our exit from the global communications business, we do not expect that this business will be included in our Other results for future periods.

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## COMPETITION

***Power Generation***. Demand for power may be met by generation capacity based on several competing technologies, such as gas-fired, coal-fired or nuclear generation and power generating facilities fueled by alternative energy sources, including hydro power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Our power generation business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities and other energy service companies in the development and operation of energy-producing projects. We believe that our ability to compete effectively in this 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 to provide reliable service to our customers. We believe our primary competitors in this business consist of approximately 19 companies.

***Natural Gas Liquids.*** Our natural gas liquids businesses face significant and varied competitors, including major integrated oil companies, major pipeline companies and their marketing affiliates and national and local gas gatherers, processors, fractionators, brokers, marketers and distributors of varying sizes and experience. The principal areas of competition include obtaining gas supplies for gathering and processing operations, obtaining supplies of raw product for fractionation, purchase and marketing of natural gas liquids, residue gas, condensate and sulfur, and transportation of natural gas and natural gas liquids and storage of natural gas liquids. Competition typically is based on location and operating efficiency of facilities, reliability of services, delivery capabilities and price. We believe our primary competitors in this business consist of approximately 21 companies.

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**REGULATION**

We are subject to regulation by various federal, state, local and foreign agencies, including the regulations described below.

Please read Environmental and Other Matters beginning on page 24 for a discussion of environmental regulations affecting our business.

***Power Generation Regulation***. The FERC has exclusive ratemaking jurisdiction over wholesale power sales in interstate commerce. Our power generation operations are subject to FERC regulation with respect to rates, the procurement and provision of certain services and operating standards. All of our current QF projects are qualifying facilities and, as such, are exempt from the ratemaking and other provisions of the FPA. Our EWGs, which are not QFs, have been granted market-based rate authority and comply with the FPA requirements governing approval of wholesale rates and subsequent transfers of project ownership interests. We are subject to the jurisdiction of the PUCT with respect to our operations in ERCOT.

In certain markets where we own power generation facilities, specifically California and New York, the FERC has, from time to time, approved temporary price caps on wholesale power sales or other market mitigation measures. In New York, the FERC approved and extended indefinitely an Automated Mitigation Procedure, or AMP, that caps bid prices based on the cost characteristics of power generating facilities, such as our DNE facilities and the Independence facility we acquired in January 2005. In January 2005, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating and remanding the FERC s orders approving the AMP in the day-ahead market outside of New York City, where our DNE facilities and Independence facility are located. At this time it is not known whether the NYISO and others have sought reconsideration of this decision; consequently, the AMP currently remains in effect.

In February 2004, the FERC accepted, subject to certain modifications, the NYISO s proposed real-time scheduling software, but rejected the NYISO s proposal to extend the real-time AMP to areas outside New York City. On rehearing in August 2004, the FERC granted rehearing and allowed the NYISO to apply the real-time AMP in the area outside New York City.

As a consequence of the California energy crisis, which arose in 2000, generation within the Cal ISO is subject to mitigation consisting primarily of a $250/MWh offer cap and an AMP that under certain conditions limits the pricing of the electricity we generate in California. All power generating facilities in California fueled by fossil fuels, including all of our California facilities, are still obligated to offer all available output subject to these restrictions.

The energy crisis also precipitated a number of other FERC actions related to the California energy market, and the Western market generally, in addition to price caps and market mitigation measures. These actions included investigations concerning alleged manipulation of energy prices in the West, including claims of false reporting of trading data to publications that publish energy indices, and complaints requesting the FERC to reform or void various long-term power sales contracts. The FERC investigation with respect to us regarding false reporting to trade publications concluded in July 2003. Additionally, in October 2004, the FERC approved an agreement providing for the settlement of certain FERC claims relating to western energy market transactions that occurred from January 2000 through June 2001. Finally, we are awaiting the outcome of an appeal to the Ninth Circuit Court of Appeals regarding the validity of our CDWR contract, which expired in December 2004. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings FERC and Related Regulatory Investigations Requests for Refunds beginning on page F-59 for further discussion of the settlement.

We are also subject to the FERC s market behavior rules, which emerged from its consideration of market manipulation in the Western markets. The rules apply to sales in organized and bilateral markets and spot

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markets, as well as long-term sales. The remedies for violating the rules could include disgorgement of unjust profits, suspension or revocation of the authority to sell at market-based rates and penalties. The extent to which the rules will affect the costs or other aspects of our operations is uncertain. However, we believe that our entities subject to the FERC s market behavior rules, which consists of our entities with market-based rates for wholesale power sales and our entity with blanket natural gas sales certificate authority, are in compliance with these rules.

The FERC s market-based rate authority allows the sale of power at negotiated rates through the bilateral market or within an organized energy market, conditioned on periodic re-review. In April 2004, the FERC issued an order concerning the ability of companies to sell electricity at market-based rates. In this order, the FERC adopted two new tests for assessing generation market power. If an applicant for market-based rate authority is found to possess generation market power under these tests and is unsuccessful in challenging that finding, the applicant may either propose mitigation measures or adopt cost-based rates. If the FERC finds that the proposed mitigation measures fail to eliminate the ability to exercise market power, the applicant s market-based rate authority will be revoked and the applicant will be subject to cost-based default rates, or other cost-based rates proposed by the applicant and approved by the FERC. The FERC issued a follow up order in May 2004 which (i) addressed the implementation process for pending and new market-based rate applications and (ii) established a timeline for entities with FERC market-based rate authority to provide the FERC with their market power assessment. Despite challenges from numerous industry participants, in July 2004 the FERC upheld the April 2004 order. These orders require entities that were previously granted market-based rate authority by the FERC, including entities with pending applications for re-review, to resubmit their applications in accordance with the new directive. Consequently, Dynegy entities with applications pending since February 2002 timely resubmitted their applications to the FERC on February 7, 2005, as required. The entities we acquired in January 2005 in connection with the Sithe Energies acquisition previously submitted updated market-based rate applications in September 2004.

In December 2004, the FERC ruled that once the MISO becomes a single market and performs functions such as single central commitment and dispatch with FERC-approved market monitoring and mitigation (currently scheduled for April 1, 2005), MISO would be considered to have a single geographic market for purposes of assessing generation market power. This ruling will enlarge the geographic area in which our DMG facilities would be evaluated for generation market power for the relevant period. Although we cannot predict with any certainty whether our applications to renew our market based rate authority will be approved or the loss of revenues that would result from the imposition of cost-based rates, an adverse outcome with respect to these applications, and the resulting requirement that we charge cost-based rates, could have a material adverse effect on our financial condition, results of operations and cash flows.

***Electricity Marketing Regulation***. Our electricity marketing operations are regulated pursuant to the FPA by the FERC with respect to rates, terms and conditions of services and various reporting requirements. As discussed above, current FERC policies permit trading and marketing entities to market electricity at market-based rates.

***Natural Gas Processing***. Our natural gas processing operations could become subject to FERC regulation. While the FERC has found that its jurisdiction under the NGA applies to plants that perform processing necessary for the safe and efficient transportation of natural gas, the FERC has historically held that the extraction of liquid hydrocarbons for their economic value is not necessary for the safe and efficient transportation of gas. Thus, if a processing plant s primary function is the extraction of natural gas liquids for their economic value, the plant is not subject to the FERC s jurisdiction. We believe our gas processing plants are primarily involved in removing natural gas liquids for economic purposes and, therefore, are exempt from FERC jurisdiction. Nevertheless, the FERC has made no specific finding as to our gas processing plants. As such, no assurance can be given that all of our processing operations will remain exempt from FERC regulation.

***Natural Gas Gathering***. The NGA exempts gas gathering facilities from the jurisdiction of the FERC, while interstate transmission facilities remain subject to FERC jurisdiction, as described above. We believe our gathering facilities and operations meet the FERC s current tests for determining non-jurisdictional gathering

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facility status, although the FERC s articulation and application of such tests have varied over time. Nevertheless, the FERC has made no specific findings as to the exempt status of any of our facilities. No assurance can be given that all of our gas gathering facilities will remain classified as such and, therefore, remain exempt from FERC regulation. Some states regulate gathering facilities to varying degrees; generally, rates are not state-regulated.

***Illinois Power Company***. During the period in which Illinois Power was a wholly-owned subsidiary of Illinova and Dynegy, it was an electric utility company as defined in PUHCA. As a result of such ownership, Illinova, the direct parent company of Illinois Power, and Dynegy were holding companies as defined in PUHCA. During this period Illinova and Dynegy were generally exempt from regulation under PUHCA based on their status as intrastate holding companies and on the application for exemption from PUHCA filed by Chevron Corporation and Chevron U.S.A. Inc. Upon the consummation of the sale of Illinois Power to Ameren in September 2004, Illinova and Dynegy were no longer holding companies as defined in PUHCA.

***Natural Gas Regulation.*** The transportation, storage and sale for resale of natural gas in interstate commerce is subject to regulation by the FERC under the NGA and, to a lesser extent, the NGPA. The FERC regulates the rates interstate pipelines charge for interstate transportation and storage services. The FERC also has jurisdiction over, among other things, the construction and operation of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion, acquisition, disposition, or abandonment of such facilities; maintenance of accounts and records; depreciation and amortization policies; and transactions with and conduct of interstate pipelines relating to affiliates. Venice Gathering System, in which we own a minority interest, is a regulated interstate pipeline. Like other interstate pipelines, Venice Gathering System must comply with FERC s open-access transportation regulations. The FERC continues to review and modify its open-access regulations and some appeals are pending.

***State Regulatory Reforms***. Our domestic power generation business is subject to various regulations from the states in which we operate. Proposed reforms to these regulations are proceeding in several states. In Illinois, both the regulators and the legislature are considering alternatives for the regulation of the retail electric markets, including how the procurement of power and energy by electric utilities will be handled following the expiration of the mandatory transition period at the end of 2006. In addition, in Texas, the PUCT has passed various rules regarding wholesale market re-design which will take effect during 2005 and 2006. In California, rules regarding resource adequacy requirements are expected to be determined by the California Public Utilities Commission, or CPUC, during 2005 and fully implemented in 2006. Although we are not regulated by the CPUC, the results of some or all of these reforms could have a material affect on our operations.

***Legislation***. The U.S. Congress is considering passage of comprehensive energy legislation that will impact us. We cannot predict with certainty if or when the U.S. Congress will finish its work on the energy legislation and send it to the President for signature or what effect any final legislation will have. Also, as noted above, in Illinois, both the regulators and the legislature are considering alternatives for the regulation of the retail electric markets, including how the procurement of power and energy by electric utilities will be handled following the expiration of the mandatory transition period at the end of 2006.

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**ENVIRONMENTAL AND OTHER MATTERS**

***General***. We incorporate environmental protection and stewardship as an integral part of the design, construction, operation and maintenance of our facilities. An important part of all of these strategies and actions is our commitment to conduct all business activities in an environmentally responsible manner.

Our operations are subject to extensive federal, state and local statutes, rules and regulations governing the discharge of materials into the environment or otherwise relating to environmental, health and safety protection. Environmental laws and regulations, including environmental regulators interpretations of these laws and regulations, are complex, change frequently and have become more stringent over time. Many environmental laws require permits from governmental authorities before construction on a project may commence or before wastes or other materials may be discharged into the environment. The process for obtaining 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 either unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures, and we may be required to incur costs to remediate contamination from past releases of wastes into the environment. Failure to comply with these statutes, rules and regulations may result in the assessment of administrative, civil and even criminal penalties. Furthermore, the failure to obtain or renew an environmental permit could prevent operation of one or more of our facilities.

In general, the construction and operation of our facilities are subject to federal, state and local environmental laws, regulations and permitting requirements governing the siting and operation of energy facilities, the discharge of pollutants and other materials into the environment, the protection of wetlands, endangered species, and other natural resources, the control and abatement of noise and other similar requirements. A variety of permits are typically required before construction of a project commences, and additional permits are typically required for facility operation.

***Environmental Expenditures***. Our aggregate expenditures for compliance with laws and regulations related to the protection of the environment were approximately $25 million in 2004, compared to approximately $51 million in 2003 and approximately $82 million in 2002. We estimate that total environmental expenditures (both capital and operating) in 2005 will be approximately $40 million. In 2005, the projected costs are associated primarily with enhanced air pollution controls and the handling of combustion byproducts. Changes in environmental regulations or the outcome of litigation could result in additional requirements that could necessitate increased future spending. Please read Environmental and Other Matters The Clean Air Act below for a discussion of the litigation brought by the Environmental Protection Agency against us relating to activities at our Baldwin generating station in Illinois.

***The Clean Air Act***. The Clean Air Act 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 and annual compliance and reporting obligations. In addition to the new source performance standards applicable to sulphur dioxide and nitrogen oxides, the Clean Air Act requires that fossil-fueled plants have sufficient sulphur dioxide and, in some geographical regions of the country, nitrogen oxides emission allowances, as well as meet certain pollutant emission standards. Our electric generation facilities are presently in compliance with these allowance and emission rate requirements. Although the impact of future air quality regulations cannot be predicted with certainty, these regulations are expected to become increasingly stringent, particularly for electric power generating facilities. Current Clean Air Act requirements include the following:

The Clean Air Act Amendments of 1990 required a two-phase reduction by electric utilities in emissions of sulfur dioxide and nitrogen oxides by 2000 as part of an overall plan to reduce acid rain in the eastern United States. Installation of control equipment and changes in fuel mix and operating practices have been completed at our facilities as necessary to comply with the emission reduction requirements of the acid rain provision of the Clean Air Act Amendment of 1990.

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In October 1998, the EPA issued a final rule on regional ozone control that required 22 eastern states and the District of Columbia to revise their State Implementation Plans to significantly reduce emissions of nitrogen oxides. The compliance deadline for implementation of these emission reductions was May 31, 2004. In January 2000, the EPA finalized another ozone-related rule under Section 126 of the Clean Air Act that has similar emission control requirements. The required capital expenditures and installation of the necessary emission control equipment to meet these requirements was completed before the compliance deadline; as a result, our power generation system met the specified compliance deadlines for implementation. Portions of our GEN and NGL businesses are also subject to similar ozone rules applicable to the Houston area. We have plans in place to satisfy these requirements and could incur capital expenditures of up to $23 million through 2007 pursuant to such plans.

***Baldwin Station Litigation***. Since November 1999, DMG has been the subject of an NOV from the EPA and a complaint filed by the EPA and the DOJ in federal district court alleging violations of the Clean Air Act and related federal and Illinois regulations related to certain maintenance, repair and replacement activities at our Baldwin generating station. We have reached agreement with the EPA, the DOJ, the State of Illinois and the environmental group intervenors on terms to settle the litigation. A consent decree was signed by all parties and lodged with the U.S. District Court for the Southern District of Illinois on March 7, 2005, and is subject to final approval of the Court following public comment. The consent decree requires us to (i) pay a $9 million civil penalty; (ii) fund several environmental projects in the additional aggregate amount of $15 million; and (iii) invest $321 million through 2010, and $224 million from 2011 through 2012, respectively, in emission control projects at our Baldwin, Vermilion and Havana plants. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57 for further discussion of this lawsuit and consent decree.

***Remedial Laws***. We are also subject to environmental requirements relating to the handling and disposal of toxic and hazardous materials, including provisions of CERCLA and RCRA and similar state laws. CERCLA imposes liability, regardless of fault or the legality of the original conduct, on persons that contributed to the release of a hazardous substance into the environment. These persons include the current or previous owner and operator of a facility and companies that disposed, or arranged for the disposal, of the hazardous substance found at a 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 the costs of cleaning up the hazardous substances that have been released and for damages to natural resources from such responsible party. Further, it is not uncommon for neighboring landowners and other affected parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. CERCLA or RCRA could impose remedial obligations at a variety of our facilities.

Additionally, the EPA may develop new regulations that impose additional requirements on facilities that store or dispose of non-hazardous fossil fuel combustion materials, including coal ash. If so, power generators like us may be required to change current waste management practices and incur additional capital expenditures to comply with these regulations.

As a result of their age, a number of our facilities contain quantities of asbestos insulation, other asbestos containing materials and lead-based paint. 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.

***Pipeline Safety***. In addition to environmental regulatory issues, the design, construction, operation and maintenance of some of our pipeline facilities are subject to the safety regulations established by the Secretary of the DOT pursuant to the NGPSA and the HLPSA, or by state regulations meeting the requirements of the NGPSA and the HLPSA, or to similar statutes, rules and regulations in other jurisdictions. In December 2000, the DOT adopted new regulations requiring operators of interstate pipelines to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could

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affect so-called high consequence environmental impact areas, through periodic internal inspection, pressure testing or other equally effective assessment means. An operator s program to comply with the new rule must also provide for periodically evaluating the pipeline segments through comprehensive information analysis, remediating potential problems found through the required assessment and evaluation, and assuring additional protection for the high consequence segments through preventative and mitigative measures. Although the requirements of this DOT rule have increased the costs of pipeline operations, we do not believe that such costs are material to our financial condition or results of operations.

In the wake of the September 11, 2001 terrorist attacks on the United States, the Coast Guard has developed a security guidance document for marine terminals and has issued a security circular that defines appropriate countermeasures for protecting them and explains how the Coast Guard plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the Coast Guard, we have specifically identified certain of our facilities as marine terminals and therefore potential terrorist targets. In compliance with the Coast Guard guidance, we performed vulnerability analyses on such marine terminals. Future analyses of our security measures may result in additional measures and procedures, which measures or procedures have the potential for increasing our costs of doing business. Regardless of the steps taken to increase security, however, we cannot be assured that our marine terminals will not become the subject of a terrorist attack. Please read Operational Risks and Insurance beginning on page 29 for further discussion.

***Health and Safety***. Our operations are subject to the requirements of OSHA and other comparable federal, state and provincial statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Superfund Amendments and Reauthorization Act and similar state statutes require that information be organized and maintained about hazardous materials used or produced in our operations. Some of this information must be provided to employees, state and local government authorities and citizens. We believe we are currently in substantial compliance, and expect to continue to comply in all material respects, with these rules and regulations.

***Summary.*** Subject to final approval of the Baldwin consent decree announced in March 2005 and described in Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57, management believes that it is in substantial compliance with, and is expected to continue to comply in all material respects with, applicable environmental statutes, regulations, orders and rules. Further, to management s knowledge, other than the previously referenced complaints, there are no existing, pending or threatened actions, suits, investigations, inquiries, proceedings or clean-up obligations by any governmental authority or third-party relating to any violations of any environmental laws with respect to our assets or pertaining to any indemnification obligations with respect to properties we previously owned or operated, which could reasonably be expected to have a material adverse effect on our operations, cash flows and financial condition.

***Ongoing Environmental Initiatives***

Following is a description of ongoing environmental initiatives for which we could incur significant capital expenditures, depending on the outcome.

***Multi-Pollutant Air Emission Initiatives***. In recent years, various federal and state legislative and regulatory multi-pollutant initiatives have been introduced to replace multiple overlapping regulatory regimes with a limited number of programs and to streamline and simplify compliance planning.

There are currently numerous multi-pollutant initiatives being considered by state and federal governments which target many of the same pollutants but contain different compliance targets and timelines, such as the Clear Skies initiative, the Clean Air Interstate Rule, or CAIR, and the Clean Air Mercury Rule. The major issues addressed by these initiatives include the transportation of ozone and particulate matter, visibility impairment or Regional Haze and emissions of other pollutants, including mercury. These initiatives are aimed at long-term reductions of multiple pollutants produced from electric generating facilities. Some of these proposed initiatives, if enacted, would also impose controls on emissions of the greenhouse gas carbon dioxide, which is emitted by all combustion sources.

Additional EPA initiatives include designation of areas as attainment, non-attainment or non-classifiable for purposes of (i) the new particulate matter 2.5 standard, or PM 2.5 standard, and (ii) the new 8-hour ozone standard. The PM 2.5 standard is aimed at the reduction of fine (smaller than 2.5 microns in diameter) particulate matter, and would impose limitations on emissions of the precursor pollutants sulphur dioxide and nitrogen oxides. The new ozone standard may result in additional nitrogen oxides reductions from power generating facilities in affected locations. Fossil fuel-fired power plants in the U.S. would be affected by the adoption of these programs or other multi-pollutant legislation currently proposed by Congress addressing similar issues. Such programs would require compliance to be achieved either by the installation of pollution controls, the purchase of emission allowances, the curtailment of operations or some combination thereof. Based on court-ordered deadlines and Congressional activity, we anticipate that some of these new requirements will be finalized in 2005. The final requirements would specify the target emission or cap levels as well as the timeframe in which compliance must be achieved.

***Water Issues.*** Our wastewater discharges are permitted under the Clean Water Act and analogous state laws. These permits are subject to review every five years. The state-issued water discharge permits associated with our DNE facilities expired in 1992. However, under New York State law, the authorization arising under these permits remains in effect and allows for continued operation under the terms of the original permit, provided that a timely and sufficient application requesting renewal has been filed as required. In May 1992, the then owner of the Danskammer facility filed a renewal application which we believe was timely and sufficient. In November 2002, several environmental groups filed suit in the Supreme Court of the State of New York seeking, among other things, a declaratory judgment that the Danskammer water intake and discharge permit expired because of alleged deficiencies in the renewal application process. In September 2004, the Court ruled that the water intake and discharge permit for our Danskammer facility is void, but stayed the enforcement of the decision pending further review by the Court or by the Appellate Division.

In October 2004, we filed our appeal of the Court s decision with the Appellate Division, and we intend to pursue vigorously our challenge to the Court s ruling voiding our permit. We will also continue to seek approval of our application to renew the water intake and discharge permit in proceedings before the New York State Department of Environmental Conservation. If our appeal is ultimately unsuccessful, we may be required to suspend operations at our Danskammer facility pending receipt of final approval of the renewal of our water intake and discharge permit. We cannot predict with any certainty the outcome of these proceedings; however, an adverse outcome, particularly a requirement that we suspend operations at our Danskammer facility for any period of time, could have a material adverse effect on our financial condition, results of operations and cash flows.

In February 2004, the EPA issued final rules, which we refer to as Rule 316(b), establishing national standards aimed at protecting aquatic life at power generating facilities with existing cooling water intake structures. This rule requires that final compliance plans be in place by January 2008. We believe that the requirements of Rule 316(b) are consistent with the provisions proposed in the Danskammer permit application. However, we expect that several of our other facilities will be impacted by the requirements of Rule 316(b), and we cannot predict what plant modifications may be necessary to comply with this rule.

As with air quality, 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 include arsenic, mercury and selenium. Significant changes in these criteria could impact station discharge limits and could require our facilities to install additional water treatment equipment.

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***Global Climate Change***. The international treaty relating to global warming (commonly known as the Kyoto Protocol) would have required reductions in emissions of greenhouse gases, primarily carbon dioxide and methane, by energy companies, including us, if adopted by the United States. As an alternative to Kyoto, which became effective (without ratification by the United States) in February 2005, current U.S. policy regarding greenhouse gases favors voluntary reductions, increased operating efficiency, and continued research and technology development. Although several bills have been introduced in Congress that would compel reductions in carbon dioxide emissions, none have advanced through the legislature and there are presently no federal mandatory greenhouse gas reduction requirements. The likelihood of any federal mandatory carbon dioxide emissions reduction program being adopted in the near future, and the specific requirements of any such program, are uncertain. However, a number of states in the Northeast and the West are in the process of developing regulatory programs to manage greenhouse gas emissions. The final program requirements and subsequent impact to our operations are not known at this time, but the Northeast states currently intend to finalize carbon dioxide emissions requirements for electric generating facilities during 2005. To the extent that any of the federal or state governments adopt or enact laws or regulations mandating a substantial reduction in greenhouse gas emissions, such mandatory reduction requirements could have far-reaching and significant implications for industry in those jurisdictions, particularly the energy industry in which we operate. Although we cannot predict the potential impact of such laws or regulations on our future financial condition, results of operations or cash flows, we will continue to monitor and participate in greenhouse gas policy developments in the regions in which we operate and will continue to assess and respond to the potential impact on our business operations.

For all of the ongoing environmental matters described above, it is difficult to predict the form that proposed rules will ultimately take and the impact that such rules, if approved, will have on our operations. It is possible that the result of these ongoing initiatives could require us and other similarly situated companies to incur material environmental compliance costs over a period of years, beginning as early as 2005.

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## OPERATIONAL RISKS AND INSURANCE

We are subject to all risks inherent in the various businesses in which we operate. These risks include, but are not limited to, explosions, fires, terrorist attacks, product spillage, weather, nature, inadequate maintenance of rights-of-way and the public, which could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or pollution of the environment, as well as curtailment or suspension of operations at the affected facility. We maintain general public liability, property/boiler and machinery, and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment. The costs associated with these insurance coverages have increased significantly during recent periods, and may continue to do so in the future. The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our potential inability to secure these levels and types of insurance in the future could negatively impact our business operations and financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates we consider commercially reasonable, particularly in the area of terrorism insurance should the Terrorism Risk Insurance Act of 2002 not be extended beyond December 2005.

In our CRM segment, we also face market, price, credit and other risks relative to our exit from the CRM business. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 83 for further discussion of these risks.

In addition to these commercial risks, we also face the risk of damage to our reputation and financial loss as a result of inadequate or failed internal processes and systems. A systems failure or failure to enter a transaction properly into the records and systems may result in an inability to settle a transaction in a timely manner or cause a contract breach. Our inability to implement the policies and procedures that we have developed to minimize these risks could increase our potential exposure to damage to our reputation in the industries in which we compete and to financial loss. Please read Item 9A. Controls and Procedures beginning on page 85 for further discussion of our internal control systems.

## SIGNIFICANT CUSTOMER

For the years ended December 31, 2004, 2003 and 2002, approximately 17%, 16% and 15%, respectively, of our consolidated revenues and approximately 22%, 22% and 44%, respectively, of our consolidated cost of sales were derived from transactions with ChevronTexaco and its subsidiaries. No other customer accounted for more than 10% of our consolidated revenues or consolidated cost of sales during 2004, 2003 or 2002.

## EMPLOYEES

At December 31, 2004, we had approximately 643 employees at our administrative offices and approximately 1,580 employees at our operating facilities. Approximately 844 employees at Dynegy-operated facilities are subject to collective bargaining agreements with various unions. We believe relations with our employees are satisfactory.

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**Item 1A.** ***Executive Officers***

Set forth below are the names and positions of our executive officers as of March 11, 2005, together with their ages and years of service with us.

| Name | Age | Position(s) | Served With the Company Since |
|---|---|---|---|
| Bruce A. Williamson | 45 | President, Chief Executive Officer and Chairman of the Board | 2002 |
| Alec G. Dreyer | 46 | Executive Vice President, Generation | 2000 |
| Stephen A. Furbacher | 57 | Executive Vice President, Natural Gas Liquids | 1996 |
| Nick J. Caruso | 59 | Executive Vice President and Chief Financial Officer | 2002 |
| Carol F. Graebner | 51 | Executive Vice President and General Counsel | 2003 |
| Peter J. Wilt | 57 | Vice President, Investor Relations | 2004 |
| R. Blake Young | 46 | Executive Vice President, Administration and Technology | 1998 |

The executive officers named above will serve in such capacities until the next annual meeting of our Board of Directors, or until their respective successors have been duly elected and have been qualified, or until their earlier death, resignation, disqualification or removal from office.

***Bruce A. Williamson*** has served as President, CEO and as a director of Dynegy since October 2002 and as Chairman of the Board of Dynegy since May 2004. Prior to joining Dynegy, Mr. Williamson served in various capacities with Duke Energy and its affiliates, most recently serving as President and Chief Executive Officer of Duke Energy Global Markets. In this capacity, he was responsible for all Duke Energy business units with global commodities and international business positions. Mr. Williamson joined PanEnergy Corporation in June 1995, which then merged with Duke Power in June 1997. Prior to the Duke-PanEnergy merger, he served as PanEnergy s Vice President of Finance. Before joining PanEnergy, he held positions of increasing responsibility at Shell Oil Company, advancing over a 14-year period to Assistant Treasurer.

***Alec G. Dreyer*** has served as Executive Vice President of our GEN segment since October 2002. Mr. Dreyer joined us in February 2000 upon consummation of the Illinova acquisition and has served various functions in our corporate finance department and power generation business. Prior to joining us, Mr. Dreyer served Illinova and its affiliates for 8 years, most recently as President of Illinova Generating Company and Senior Vice President of Illinova and Illinois Power. He was responsible for developing Illinova s spin off of its fossil-fueled generation fleet into an unregulated entity, which is now known as DMG.

***Stephen A. Furbacher*** has served as Executive Vice President of our NGL segment since September 1996. He joined us in May 1996, just prior to our acquisition of Chevron s midstream business. Before joining us, he served as President of Warren Petroleum Company, the natural gas liquids division of Chevron U.S.A. He began his career with Chevron in August 1973 and served in positions of increasing responsibility before being named President of Warren Petroleum Company in July 1994.

***Nick J. Caruso*** has served as our Executive Vice President and Chief Financial Officer since December 2002. Mr. Caruso is responsible for our internal audit, risk management, tax, treasury, accounting and finance functions. He was previously employed by Shell Oil Company from June 1969 to December 2001. He most recently served as that company s Vice President of Finance and Chief Financial Officer before retiring in December 2001. He was responsible for the controller s organization, treasury, insurance, auditing and retirement funds, interfacing with the board of directors on internal controls, and preparation of financial statements.

***Carol F. Graebner*** has served as our Executive Vice President and General Counsel since March 2003. Prior to joining us, Ms. Graebner was employed by Duke Energy International, where she served as senior vice president and general counsel and was responsible for providing all legal, regulatory and governmental affairs

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services for that company s international merchant energy business. Prior to joining Duke Energy International in November 1998, she served in various positions of increasing responsibility at Conoco Inc., advancing over a 16-year period to general counsel of Conoco Global Power, Inc.

***Peter J. Wilt*** has served as our Vice President, Investor Relations since April 2004. Mr. Wilt is responsible for serving as a liaison between our management, the investing public and the financial community, including portfolio managers and research analysts. He is also responsible for communicating our financial results, operational performance and business strategies to the investment community. Mr. Wilt previously served Duke Energy International as Executive Vice President, Europe from May 2002 through April 2004, and as Executive Vice President, Latin America, from November 1999 through May 2002.

***R. Blake Young*** has served as our Executive Vice President of Administration and Technology since October 2002. Formerly President of Global Technology, Mr. Young is responsible for strategic planning, corporate technology, corporate communications, human resources, divestitures and corporate shared services. In addition, Mr. Young served as Executive Vice President and Chief Operating Officer of Illinois Power from February 2004 through April 2004, and as President of Illinois Power from April 2004 through September 2004. In these capacities he assumed the overall responsibility for Illinois Power and its transition to Ameren during the regulatory approval process. Prior to joining us in October 1998, he worked for Campbell Soup Company where he was responsible for technology deployment across its U.S. grocery division and served as head of global business systems strategy. Mr. Young was previously employed by Tenneco Energy for approximately 13 years, where he served as Vice President and Chief Information Officer.

**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 beginning on page 1. Those descriptions are incorporated herein by this reference. Substantially all of our assets, including the physical operating properties we own, are pledged as collateral with respect to the DHI amended credit facility and the DHI second priority senior secured notes on a first lien and second lien, respectively. Please read Note 11 Debt beginning on page F-42 for further discussion of the amended credit facility.

Our principal executive office located in Houston, Texas is held under a lease that expires in December 2007. We also lease additional offices in the states of California, Colorado, Florida, Georgia, Illinois, Massachusetts, and Texas.

**Item 3.** ***Legal Proceedings***

For a description of our material legal proceedings, please read Note 16 Commitments and Contingencies beginning on page F-55, which is incorporated herein by reference.

**Item 4.** ***Submission of Matters to a Vote of Security Holders***

No matter was submitted to a vote of our security holders during the fourth quarter 2004.

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**PART II**

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

Our Class A common stock, no par value per share, is listed and traded on the New York Stock Exchange under the ticker symbol DYN. The number of stockholders of record of our Class A common stock as of March 4, 2005, based upon records of registered holders maintained by our transfer agent, was 20,712.

Our Class B common stock, no par value per share, is neither listed nor traded on any exchange. All of the shares of Class B common stock are owned by Chevron U.S.A. Inc., which we refer to as Chevron.

The following table sets forth the high and low closing sales prices for the Class A common stock for each full quarterly period during the fiscal years ended December 31, 2004 and 2003, as reported on the New York Stock Exchange Composite Tape.

**Summary of Dynegy s Common Stock Price**

| | High | Low |
|---|---|---|
| 2004: | | |
| Fourth Quarter | $ 5.86 | $ 4.27 |
| Third Quarter | 4.99 | 3.93 |
| Second Quarter | 4.44 | 3.75 |
| First Quarter | 5.15 | 3.46 |
| 2003: | | |
| Fourth Quarter | $ 4.35 | $ 3.45 |
| Third Quarter | 4.65 | 2.85 |
| Second Quarter | 5.23 | 2.54 |
| First Quarter | 2.63 | 1.29 |

During the fiscal years ended December 31, 2004 and 2003, our Board of Directors did not elect to pay a common stock dividend. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Dividends on Preferred and Common Stock beginning on page 48 for further discussion of our dividend policy and the impact of dividend restrictions contained in our financing agreements. Any decision to pay a dividend is at the discretion of the Board of Directors, but we do not expect to pay a common stock dividend in the foreseeable future.

**Shareholder Agreement**

In June 1999, Chevron, now a subsidiary of ChevronTexaco, entered into a shareholder agreement with us governing certain aspects of our relationship. The agreement was executed in February 2000, upon closing of the merger with Illinova, and reflected agreements negotiated between us and Chevron relating to Chevron s significant ownership interest in Dynegy. The agreement amended certain of the rights and obligations previously agreed between us and Chevron at the time of Chevron s initial investment in 1996. In August 2003, we entered into an amended and restated shareholder agreement with Chevron in connection with the consummation of the Series B Exchange. Please read Note 12 Related Party Transactions Series B Preferred Stock beginning on page F-47 for further discussion of the Series B Exchange. The material terms of this amended and restated shareholder agreement, which we refer to as the shareholder agreement, are described below.

The shareholder agreement grants Chevron preemptive rights to acquire shares of our common stock in proportion to its then-existing interest in our equity value whenever we issue any equity securities, including

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securities issued pursuant to employee benefit plans. Chevron agreed to waive its preemptive rights in respect of the equity securities we issued in connection with the Series B Exchange and our August 2003 refinancing and up to $250 million in equity securities we may issue in one or more future underwritten offerings.

In addition, Chevron and its affiliates may acquire up to 40% of the total combined voting power of our outstanding voting securities without restriction in the shareholder agreement. Shares of Class B common stock issued to Chevron upon the mandatory conversion of Chevron s Class C convertible preferred stock are not counted when calculating this 40% threshold. We have agreed not to take any action that would cause Chevron s ownership to exceed this 40% threshold.

If Chevron or its affiliates wish to acquire more than 40% of the total combined voting power of our outstanding voting securities, the shareholder agreement requires Chevron to make an offer to acquire all of our outstanding voting securities for cash or freely tradable securities listed on a national securities exchange. Any offer by Chevron or its affiliates for all of our outstanding voting securities would be subject to the auction procedures outlined in the agreement.

Chevron s ownership of our Class B common stock entitles it to designate up to three members of our Board of Directors. The shareholder agreement prohibits Chevron from selling or transferring shares of Class B common stock except in the following transactions:

- a widely-dispersed public offering;
- an unsolicited sale to a third party, provided that we or our designee are given the opportunity to purchase the shares proposed to be sold; or
- a solicited sale to an acceptable third party, provided that if we advise Chevron that the sale to a third party is not acceptable, we must purchase all of the offered shares for cash at a purchase price equal to 105% of the third party offer.

Upon the sale or transfer to any person other than an affiliate of Chevron, the shares of Class B common stock automatically convert into shares of Class A common stock.

The shareholder agreement further provides that we may require Chevron and its affiliates to sell all of the shares of Class B common stock under specified circumstances. These rights are triggered if Chevron or its Board designees block which they are entitled to do under our Bylaws any of the following transactions two times in any 24-month period or three times over any period of time:

- the issuance of new shares of stock where the aggregate consideration to be received exceeds the greater of $1 billion or one-quarter of our total market capitalization;
- any disposition of all or substantially all of our NGL business while substantial agreements between Chevron and us exist (except for a contribution of such liquids business to an entity in which we have a majority direct or indirect interest);

any merger, consolidation, joint venture, liquidation, dissolution, bankruptcy, acquisition of stock or assets, or issuance of common or preferred stock, any of which would result in payment or receipt of consideration having a fair market value exceeding the greater of $1 billion or one-quarter of our total market capitalization; or

any other material transaction or series of related transactions which would result in the payment or receipt of consideration having a fair market value exceeding the greater of $1 billion or one-quarter of our total market capitalization.

However, upon occurrence of one of these triggering events and in lieu of selling Class B common stock, Chevron may elect to retain the shares of Class B common stock but forfeit its right and the right of its Board

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designees to block the subject transaction. A block consists of a vote against a proposed transaction by either (a) all of Chevron s representatives on our Board of Directors present at the meeting where the vote is taken (if the transaction would otherwise be approved by our Board of Directors) or (b) any of the Class B common stock held by Chevron and its affiliates if the transaction otherwise would be approved by at least two-thirds of all other shares entitled to vote on the transaction, excluding shares held by our management, directors or subsidiaries.

The shareholder agreement also prohibits us from taking the following actions:

issuing any shares of Class B common stock to any person other than Chevron and its affiliates;

adopting a shareholder rights plan, poison pill or similar device that prevents Chevron from exercising its rights to acquire shares of common stock or from disposing of its shares when required by us; and

acquiring, owning or operating a nuclear power facility, other than being a passive investor in a publicly-traded company that owns a nuclear facility.

Generally, the provisions of the shareholder agreement terminate on the date Chevron and its affiliates cease to own shares representing at least 15% of our outstanding voting power. At such time all of the shares of Class B common stock held by Chevron would convert to shares of Class A common stock.

**Securities Authorized for Issuance Under Equity Compensation Plans**

The following table sets forth certain information as of December 31, 2004 as it relates to our equity compensation plans for our Class A common stock, the only class with respect to which we offer equity compensation.

| Plan Category | Number of securities to be issued upon exercise of outstanding options, warrants and rights | Weighted-average exercise price of outstanding options, warrants and rights (b) | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c) |
|---|---|---|---|

| | (a) | | |
|---|---|---|---|
| Equity compensation plans approved by security holders | 7,506,236 | $ 16.83 | 26,931,419 |
| Equity compensation plans not approved by security holders (1) | 3,856,434 | $ 18.01 | 5,996,678 |
| Total | 11,362,670 | $ 17.23 | 32,928,097 |

(1) The plans that were not approved by our security holders are as follows: Extant Plan, Dynegy 2001 Non-Executive Stock Incentive Plan and Dynegy UK Plan. Please read Note 18 Capital Stock Stock Options beginning on page F-71 for a brief description of our equity compensation plans, including these plans.

**Item 6.** ***Selected Financial Data***

The selected financial information presented below 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 Management s Discussion and Analysis of Financial Condition and Results of Operations. Earnings (loss) per share ( EPS ), shares outstanding for EPS calculation and cash dividends per common share have been adjusted for a two-for-one stock split on August 22, 2000 and, for all periods prior to February 1, 2000, the 0.69-to-one exchange ratio in the Illinova acquisition.

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As discussed in the Explanatory Note to the accompanying Consolidated Financial Statements, the historical information in the accompanying Consolidated Financial Statements has been restated. Please read the Explanatory Note to the accompanying Consolidated Financial Statements beginning on page F-10 for additional information about these restatements. The selected financial data that follows has been adjusted to reflect these restatements.

**Dynegy s Selected Financial Data**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2001 | 2000 |
| | | (Restated) | (Restated) | (Restated) | (Restated) |
| | (in millions, except per share data) | | | | |
| **Statement of Operations Data (1):** | | | | | |
| Revenues | $ 6,153 | $ 5,787 | $ 5,326 | $ 9,124 | $ 9,715 |
| Depreciation and amortization expense | (323) | (454) | (466) | (452) | (386) |
| Goodwill impairment | | (311) | (814) | | |
| Impairment and other charges | (83) | (225) | (190) | | |
| General and administrative expenses | (352) | (346) | (325) | (420) | (312) |
| Operating income (loss) | 192 | (594) | (1,058) | 971 | 770 |
| Interest expense | (480) | (509) | (297) | (255) | (247) |
| Income tax benefit (expense) | 89 | 246 | 343 | (366) | (231) |
| Net income (loss) from continuing operations | (10) | (713) | (1,199) | 481 | 416 |
| Income (loss) from discontinued operations (3) | (5) | (19) | (1,154) | (82) | 27 |
| Cumulative effect of change in accounting principles | | 40 | (234) | 2 | |
| Net income (loss) | $ (15) | $ (692) | $ (2,587) | $ 401 | $ 443 |
| Net income (loss) applicable to common stockholders | (37) | 321 | (2,917) | 359 | 408 |
| Basic earnings (loss) per share from continuing operations | $ (0.09) | $ 0.80 | $ (4.18) | $ 1.35 | $ 1.26 |
| Basic net income (loss) per share | (0.10) | 0.86 | (7.97) | 1.10 | 1.35 |
| Diluted earnings (loss) per share from continuing operations | $ (0.09) | $ 0.73 | $ (4.18) | $ 1.29 | $ 1.21 |
| Diluted net income (loss) per share | (0.10) | 0.78 | (7.97) | 1.05 | 1.30 |
| Shares outstanding for basic EPS calculation | 378 | 374 | 366 | 326 | 302 |
| Shares outstanding for diluted EPS calculation | 504 | 423 | 370 | 340 | 315 |
| Cash dividends per common share | $ | $ | $ 0.15 | $ 0.30 | $ 0.25 |
| **Cash Flow Data:** | | | | | |
| Cash flows from operating activities | $ 5 | $ 876 | $ (25) | $ 550 | $ 420 |
| Cash flows from investing activities | 262 | (266) | 677 | (3,828) | (1,539) |
| Cash flows from financing activities | (115) | (900) | (44) | 3,450 | 1,131 |
| Cash dividends or distributions to partners, net | (22) | | (55) | (98) | (112) |
| Capital expenditures, acquisitions and investments | (314) | (338) | (981) | (4,687) | (2,415) |

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| | December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2001 | 2000 |
| | | (Restated) | (Restated) (in millions) | (Restated) | (Restated) |
| **Balance Sheet Data (2):** | | | | | |
| Current assets | $ 2,752 | $ 3,086 | $ 7,586 | $ 8,956 | $ 10,827 |
| Current liabilities | 1,802 | 2,450 | 6,748 | 8,538 | 10,286 |
| Property and equipment, net | 6,130 | 8,178 | 8,458 | 9,269 | 7,148 |
| Total assets | 9,852 | 12,810 | 20,029 | 25,083 | 22,572 |
| Long-term debt (excluding current portion) | 4,332 | 5,893 | 5,454 | 5,016 | 3,754 |
| Notes payable and current portion of long-term debt | 34 | 331 | 861 | 458 | 118 |
| Serial preferred securities of a subsidiary | | 11 | 11 | 46 | 46 |
| Subordinated debentures | | | 200 | 200 | 300 |
| Series B Preferred Stock (4) | | | 1,212 | 882 | |
| Series C convertible preferred stock | 400 | 400 | | | |
| Minority interest (5) | 106 | 121 | 146 | 1,040 | 1,022 |
| Capital leases not already included in long-term debt | | | 15 | 29 | 15 |
| Total equity | 1,867 | 1,886 | 2,167 | 4,867 | 3,376 |

(1) The following acquisitions were accounted for in accordance with the purchase method of accounting and the results of operations attributable to the acquired businesses are included in our financial statements and operating statistics beginning on the acquisitions effective date for accounting purposes:

Northern Natural  February 1, 2002;

BGSL  December 1, 2001;

iaxis  March 1, 2001;

Extant  October 1, 2000; and

Illinova  January 1, 2000.

(2) The Northern Natural, BGSL, iaxis, Extant and Illinova acquisitions were each accounted for under the purchase method of accounting. Accordingly, the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as of the effective dates of each transaction. See note (1) above for respective effective dates.

(3) Discontinued operations includes the results of operations from the following businesses:

Northern Natural (sold third quarter 2002);

U.K. Storage  Hornsea facility (sold fourth quarter 2002) and Rough facility (sold fourth quarter 2002);

DGC (portions sold in fourth quarter 2002 and first and second quarters 2003);

Global Liquids (sold fourth quarter 2002); and

U.K. CRM (substantially liquidated in first quarter 2003).

(4) The 2002 amount equals the $1.5 billion in proceeds related to the Series B Preferred Stock less the $660 million implied dividend recognized in connection with the beneficial conversion option plus $372 million in accretion of the implied dividend through December 31, 2002. The 2001 amount equals the $1.5 billion in proceeds less the $660 million implied dividend plus $42 million in accretion of the implied dividend through December 31, 2001. Please read Note 12  Related Party Transactions  Series B Preferred Stock beginning on page F-47 for further discussion.

(5) The 2001 and 2000 amounts include amounts relating to the Black Thunder Secured Financing. This financing involved (i) our investment of $100 million in June 2000 in Catlin Associates, L.L.C., an entity which holds indirect economic interests in some of our Midwest generation assets, including the coal-fired generation units in Illinois, and (ii) our obligation to purchase the $850 million interest held by a third party on or before June 2005. We repaid the balance owed under this financing in August 2003.

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**Item 7.** ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

*The following discussion should be read together with the audited 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 in two areas of the energy industry: power generation and natural gas liquids. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. As described below, our regulated energy delivery business, which was conducted through Illinois Power and its subsidiaries, was sold to Ameren Corporation in September 2004. We also separately report the results of our customer risk management business, which primarily consists of our three remaining power tolling arrangements (excluding the Independence toll, which is now part of our GEN segment) as well as our gas transportation contracts, and legacy gas and power trading positions. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and infrastructure depreciation and amortization, but because of their nature, these items are not reported as a separate segment.

Following is a brief discussion of each of our three current business 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. This Overview section concludes with a discussion of strategic growth opportunities and a summary of our current liquidity position and items that could impact our liquidity position in 2005 and beyond. Please note that this Overview section is merely a summary and should be read together with the remainder of this Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, as well as our audited consolidated financial statements, including the notes thereto, and the other information included in this report.

***Power Generation***. Our power generation business owns or leases more than 12,700 MWs of net generating capacity located in six regions of the United States, including the facilities recently acquired in the Sithe Energies acquisition. Our power generating fleet is diversified by facility type (base load, intermediate and peaking), fuel source and geographic location. We generate earnings and cash flows in this business through sales of energy and capacity.

The primary factors impacting our power generation earnings and cash flows are the prices for power, natural gas and coal, which in turn are largely driven by supply and demand. Demand for power can vary regionally due to, among other things, weather and general economic conditions. Power supplies similarly vary by region and are impacted significantly by available generating capacity, transmission capacity and federal and state regulation. We also are impacted by the relationship between prices for power and natural gas, commonly referred to as the spark spread, and its impact on the cost of generating electricity. However, we believe that our significant coal-fired and fuel oil generating facilities partially mitigate our sensitivity to changes in the spark spread, in that coal and fuel oil prices are relatively stable and insensitive to changes in gas prices, and position us for potential increases in earnings and cash flows in an environment where both power and gas prices increase. We have entered into long-term coal supply and transportation agreements for our Midwest fleet. Please read Liquidity and Capital Resources Internal Liquidity Sources Cash Flows from Operations beginning on page 48 for a discussion of our views on the current pricing environment and its anticipated long-term recovery.

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

- our ability to control our capital expenditures, which primarily are limited to maintenance, safety, environmental and reliability projects, and to control other costs through disciplined management and safe, efficient operations;

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our ability to optimize our assets through hedging activities and similar transactions, which is affected by general market liquidity and the need to satisfy counterparties collateral requirements given our non-investment grade credit ratings; and

our ability to enter into new sales contracts and to renew our existing contracts.

***Natural Gas Liquids***. Our natural gas liquids business owns natural gas gathering and processing, or upstream, assets in key producing areas of Louisiana, New Mexico and Texas. This business also owns integrated downstream assets used to fractionate, store, terminal, transport, distribute and market natural gas liquids. These downstream assets generally are connected to and supplied by our and third parties upstream assets and are located in Mont Belvieu, Texas, the hub of the U.S. natural gas liquids business, and West Louisiana.

We generate earnings and cash flows in the upstream business by selling our gathering, processing and treating services to producers. We generate earnings and cash flows in our downstream business through sales of our fractionation, storage, transportation and terminalling services and sales of natural gas liquids through our marketing operations.

The earnings and cash flows that we generate in this business are sensitive to natural gas and natural gas liquids prices and, to a lesser extent, the relationship between the two, commonly referred to as the frac spread. Our current contract mix has minimal exposure to frac spread risk. Please read Item 1. Business Segment Discussion Natural Gas Liquids Upstream Business beginning on page 10 for a detailed discussion of our current upstream contract portfolio.

In addition to commodity prices, other factors that have impacted, and are expected to continue to impact, the earnings and cash flows for this business include:

our ability to control our capital expenditures, which primarily are limited to maintenance, safety and reliability projects, and control other costs through disciplined management and safe, efficient operations;

reduced market liquidity and our obligation to post collateral to or prepay counterparties because of our non-investment grade credit ratings, which limit our ability to contract forward physically for some of our natural gas liquids products;

producer drilling activity, which is significantly affected by commodity prices;

a varying frac spread environment and the resulting impact on volumes available for fractionation, distribution and marketing;

the petrochemical industry s need for and utilization of our natural gas liquids as feedstocks and related natural gas liquids facilities to provide distribution and logistics services;

our ability to manage our natural gas liquids inventories efficiently; and our ability to meet customer demands for timely delivery and transportation.

***Regulated Energy Delivery***. Our regulated energy delivery segment was comprised of our Illinois Power subsidiary prior to its sale to Ameren in September 2004. From February 2002 through July 2002, this segment, formerly called the Transmission and Distribution segment, also included the results of Northern Natural. Northern Natural s results for this period are reflected in Discontinued Operations in our consolidated statements of operations.

***Customer Risk Management.*** Our customer risk management business primarily consists of the Gregory power tolling arrangement, which expires in July 2005, the Kendall power tolling arrangement, the effect of which we have mitigated through November 2008 and the Sterlington power tolling arrangement, as well as our gas transportation contracts and legacy gas and power trading positions. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Kendall beginning on page F-25 below for further discussion of the Kendall toll. Our Independence

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power tolling arrangement and the related gas transportation contracts, which were previously part of our CRM segment, were reclassified as intercompany transactions upon our consummation of the Sithe Energies acquisition, and, as of February 2005, are part of our GEN segment, as they relate to the operation of the power generation assets acquired from Exelon. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion. We have significant, long-term fixed obligations associated with our tolling arrangements, which obligations may substantially exceed the earnings and cash flows we expect to generate in connection with these arrangements. Our ability to mitigate partially the negative impact of these arrangements on our earnings and cash flows depends on the price of power and the spark spread in the regions where the plants covered by those tolls are located. It also will be significantly impacted by our ability to restructure or terminate one or more of our remaining power tolling arrangements, which we expect would require a significant cash payment.

Regarding our legacy gas and power trading positions, we have substantially reduced the size of our portfolio relative to when we were primarily a marketing and trading company. Please read Item 1. Business Segment Discussion Customer Risk Management beginning on page 18 for further discussion.

***Other***. Beginning January 1, 2003, Other includes corporate-level items that were previously allocated to our operating segments. Significant items impacting future earnings and cash flows include:

- interest expense, which increased beginning in 2003 as a result of our refinancing and restructuring activities and will continue to reflect our non-investment grade credit ratings;

- general and administrative costs, with respect to which we have implemented a number of initiatives that have yielded savings; general and administrative costs also will be impacted by, among other things, (i) any future corporate-level litigation reserves or settlements and (ii) potential funding requirements under our pension plans; and

- income taxes, with respect to which we currently only pay minimal state and foreign income taxes; income taxes will also be impacted by our ability to realize our significant deferred tax assets, including loss carryforwards.

In addition, dividends associated with our outstanding preferred stock will continue to affect our earnings available to our common shareholders.

***Strategic Growth Opportunities***. With only a few significant legacy matters remaining to be addressed, more of our company s resources are available to continue our efforts to operate our energy businesses safely, reliably and efficiently, to manage the costs across our organization and to deliver value to our investors. We are also continuing to focus on identifying and evaluating strategic growth opportunities, particularly organic or bolt-on projects, such as the conversion of our Havana power generating facility to lower-cost and lower-emission PRB coal, to improve the operational performance and efficiency of certain assets, enabling us to realize costs savings and to capture even more of the benefit of increases in commodity prices. Such opportunities may also include merger and acquisition activities, which we discuss and evaluate as part of our ongoing business strategy. In the power generation industry, in particular, we believe that consolidation is likely to occur within the next several years. We further believe that our efficient and scalable operations platform, together with our multi-fuel capabilities and multi-region presence, position us to benefit from opportunities that might arise in connection with any acquisition or consolidation transactions. However, our desire or ability to pursue in any such opportunities is subject to a number of factors beyond our control. As such, we cannot guarantee that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities on our financial condition or results of operations.

***Liquidity***. As of March 4, 2005, we had cash on hand of $365 million and available borrowing capacity of $611 million, for total liquidity of nearly $1 billion. During 2004, we continued to reduce our debt and other obligations while maintaining liquidity between $1.2 billion and $1.7 billion. The sale of Illinois Power provided significant cash proceeds and advanced our business strategy of focusing on our unregulated energy businesses. In January 2005, we used approximately $135 million of liquidity to pay the cash portion of the purchase price for the Sithe Energies acquisition.

For the next twelve months, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be positive, but insufficient to satisfy our capital expenditures and debt maturities. However, we believe that our cash on hand and the $100 million deposited into escrow in connection with the sale of Illinois Power, which we expect to receive following approval of the Baldwin consent decree announced in March 2005, together with capacity under our $700 million revolving credit facility, will be sufficient to discharge these obligations. To further our deleveraging efforts, we may consider other capital-raising activities, including potential equity issuances.

Over the longer term and through the anticipated recovery of the U.S. power markets, we expect to maintain sufficient liquidity to satisfy our debt and commercial obligations and provide collateral support through operating cash flows, capacity under our revolving credit facility (or any refinancing thereof), as well as proceeds from anticipated refinancings of debt maturities.

Our ability to generate operating cash flows will be impacted by a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for power and natural gas, and the success of our ongoing efforts to manage operating costs, particularly fuel requirements, and capital expenditures. Our ability to refinance our substantial debt maturities is primarily dependent upon our ability to generate operating cash flows, which is subject to the factors described in the preceding sentence. Over the longer term we believe that power prices will improve in some or all of the regions in which we operate as the supply-demand imbalance for power decreases. Much of our restructuring work has positioned us to benefit from earnings and growth opportunities associated with an expected recovery in the U.S. power markets. Additionally, our NGL business is currently operating in a highly favorable pricing environment. Our future financial condition and results of operations will be materially adversely affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant, prolonged pricing deterioration below price levels experienced over the last few years in our NGL segment.

Our longer term liquidity position and financial condition will also be significantly impacted by the availability of, and our ability to pursue, strategic growth opportunities. However, our desire or ability to pursue any such opportunities is subject to a number of factors beyond our control. As such, we cannot guarantee that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities on our financial condition or results of operations.

Please read Uncertainty of Forward-Looking Statements and Information for additional factors that could impact our future operating results and financial condition.

## LIQUIDITY AND CAPITAL RESOURCES

### Overview

Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, collateral requirements, fixed capacity payments and contractual obligations, capital expenditures, legal settlements and working capital needs. Examples of working capital needs include prepayments or cash collateral associated with purchases of commodities, particularly natural gas, coal and natural gas liquids, facility maintenance costs and other costs such as payroll. Our liquidity and capital resources are primarily derived from cash flows from operations, cash on hand, borrowings under our financing agreements, asset sale proceeds and proceeds from capital market transactions, to the extent that we engage in these activities prospectively.

### Debt Obligations

During 2004, we continued our efforts to reduce our debt maturities and extend our maturity profile, which included the following transactions:

- Replacement of our $1.1 billion credit facility, scheduled to mature in February 2005, with a new $1.3 billion credit facility comprised of a revolving credit facility and a term loan, which are scheduled to mature in May 2007 and May 2010, respectively;

- Prepayment of all outstanding indebtedness and other amounts owed under the ABG Gas Supply Financing, primarily through use of $154 million in proceeds from the May 2004 term loan;

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Payment of $81 million in connection with the termination of the Tilton capital lease;

The sale of Illinois Power to Ameren Corporation, which eliminated Illinois Power s $1.8 billion in debt and preferred stock obligations from our consolidated balance sheet; and

Redemption of all outstanding ChevronTexaco junior notes, primarily through the use of $125 million of the proceeds from the Illinois Power sale.

As a result of our efforts, our aggregate maturities for long-term debt as of December 31, 2004 were reduced to $24 million in 2005, $28 million in 2006, $188 million in 2007 (excluding the maturity of our $700 million revolving credit facility), $231 million in 2008, $6 million in 2009 and approximately $3.9 billion thereafter. Maturities for 2005 represent our principal payments on our term loan and our 8.125% DHI senior notes and exclude the non-cash amortization of basis adjustments included in Notes payable and current portion of long-term debt on our consolidated balance sheets.

Furthermore, upon the closing of the Sithe Energies acquisition, our balance sheet will reflect the consolidation of the fair value of approximately $919 million in face value project debt. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion of this transaction.

We have incurred significant debt service obligations in the course of extending our debt maturities. We also are subject to covenants in the related transaction agreements that are substantially more restrictive than those typically found in financing agreements of borrowers with investment grade credit ratings, including covenants limiting our ability to incur additional debt and sell certain assets. We are currently in compliance with these restrictive covenants, but our future financial condition and results of operations could be materially adversely affected by our ability to comply with these restrictive covenants in the future.

The following table depicts our consolidated third-party debt obligations, including the principal-like maturities associated with the DNE leveraged lease, and the extent to which they are secured as of December 31, 2004 and 2003:

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| | (in millions) | |
| First Secured Obligations | | |
| Dynegy Holdings Inc. | $ 1,551 | $ 1,127 |
| Illinois Power (1) | | 1,967 |
| Total First Secured Obligations | 1,551 | 3,094 |
| Second Secured Obligations | 1,750 | 1,750 |
| Unsecured Obligations | 1,831 | 2,160 |
| Subtotal | 5,132 | 7,004 |
| Preferred Obligations | 400 | 411 |

| | | |
|---|---|---|
| Total Obligations | $ 5,532 | $ 7,415 |
| Less: DNE Lease Financing (3) | (771) | (758) |
| Less: Preferred Obligations | (400) | (411) |
| Other (2) | 5 | (22) |
| Total Notes Payable and Long-term Debt | $ 4,366 | $ 6,224 |

(1) Ameren assumed Illinois Power s debt obligations on September 30, 2004 upon closing of our sale of Illinois Power. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23 for further discussion.

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(2) Consists of net premiums on debt of $5 million at December 31, 2004; net discounts on debt of $12 million at December 31, 2003; and the $10 million difference between the carrying value of the Tilton capital lease and the purchase obligation of $81 million at December 31, 2003.
(3) Represents present value of future lease payments discounted at 10%.

**Collateral Postings**

We continue to use a significant portion of our capital resources, in the form of cash and letters of credit, to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The following table summarizes our consolidated collateral postings to third parties by segment at March 4, 2005, December 31, 2004 and December 31, 2003:

| | March 4, 2005 | December 31, 2004 | December 31, 2003 |
|---|---|---|---|
| | | (in millions) | |
| **By Segment:** | | | |
| GEN | $ 176 | $ 192 | $ 136 |
| CRM | 80 | 94 | 121 |
| NGL | 167 | 167 | 179 |
| REG | 10 | 10 | 38 |
| Other | 9 | 7 | 8 |
| Total | $ 442 | $ 470 | $ 482 |
| **By Type:** | | | |
| Cash | $ 353 | $ 376 | $ 294 |
| Letters of Credit | 89 | 94 | 188 |
| Total | $ 442 | $ 470 | $ 482 |

The increase in collateral postings for the GEN of $40 million is primarily a result of increased commodity prices, particularly the price of electricity, as well as increased coal purchases and collateral posted in connection with new electric capacity sales transactions. Additionally, as of February 2005, our Independence power tolling arrangement and financial derivative instrument and the related gas transportation contracts (and the collateral posted in connection with these obligations), which were previously part of our CRM segment, were transformed into intercompany obligations under our GEN segment. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion.

This increase in our collateral postings was offset by reductions in collateral postings in our other segments, including the $41 million reduction of collateral posted in support of our CRM segment primarily resulting from (i) the termination of the ABG Gas Supply contract in August 2004 and (ii) the execution of a master netting agreement with a significant counterparty, which were offset by $22.5 million of collateral posted in connection with an existing natural gas transaction. Additionally, the year end 2003 balance, in support of our NGL segment, included collateral posted with respect to the purchase of natural gas liquids inventory transported by barge. Finally, collateral postings at our REG segment have decreased by $28 million due to the sale of Illinois Power. We expect that the remaining $10 million of collateral relating to that segment will be eliminated in the first quarter 2005.

While the total amount of collateral posted decreased, we have increased the proportion of cash used to satisfy counterparty collateral demands. As of December 31, 2003, approximately 61% of the aggregate collateral posted (or approximately $294 million) consisted of cash, compared to approximately 80% cash

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collateral (or approximately $376 million) as of December 31, 2004 and 80% cash collateral (or approximately $353 million) as of March 4, 2005. This increase is the result of the termination of the ABG Gas Supply contract and our ongoing efforts to post cash collateral in lieu of letters of credit, to the extent economical, to avoid paying the 4.00% per annum letter of credit fee payable under our revolving credit facility.

Going forward, we expect counterparties 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. Considering current commodity price estimates, our credit ratings, the timing of contract settlements, the anticipated level of new capacity sales agreements and forward hedging transactions, we believe that collateral requirements will be between $375 million and $400 million at year-end 2005. We believe that we have sufficient capital resources to satisfy counterparties collateral demands, including those for which no collateral is currently posted, for at least the next twelve months. Over the longer term, we expect to achieve incremental reductions associated with the completion of our exit from the CRM business.

**Disclosure of Contractual Obligations and Contingent Financial Commitments**

We incur contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contracts, 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 operating activities. Financial commitments represent contingent obligations, such as financial guarantees, that become payable only if specified events occur. Details on these obligations are set forth below.

***Contractual Obligations***

The following table summarizes our contractual obligations as of December 31, 2004. Cash obligations reflected are not discounted and do not include related interest, accretion or dividends.

| | Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Total** | **2005** | **2006** | **2007** | **2008** | **2009** | **Thereafter** |
| Long-Term Debt (including Current Portion) | $ 4,366 | $ 34 | $ 28 | $ 188 | $ 231 | $ 6 | $ 3,879 |
| Redeemable Preferred Securities | 400 | | | | | | 400 |
| Operating Leases | 1,622 | 93 | 93 | 141 | 158 | 161 | 976 |
| Capacity Payments | 2,242 | 208 | 191 | 194 | 200 | 201 | 1,248 |
| Conditional Purchase Obligations | 124 | 14 | 13 | 14 | 14 | 14 | 55 |
| Pension Funding Obligations | 73 | 28 | 19 | 26 | | | |
| Total Contractual Obligations | $ 8,827 | $ 377 | $ 344 | $ 563 | $ 603 | $ 382 | $ 6,558 |

***Long-Term Debt (including Current Portion).*** Total amounts of Long-Term Debt (including Current Portion) are included in the December 31, 2004 Consolidated Balance Sheet. For additional explanation, please read Note 11 Debt beginning on page F-42.

Additionally, we have entered into various joint ventures principally to share risk or optimize existing commercial relationships. These joint ventures maintain independent capital structures and, where necessary, have financed their operations on a non-recourse basis to us. Please read Note 9 Unconsolidated Investments beginning on page F-37 for further discussion of these joint ventures.

***Redeemable Preferred Securities.*** Total amounts of Redeemable Preferred Securities are included in the December 31, 2004 Consolidated Balance Sheet. For additional explanation, please read Note 14 Redeemable Preferred Securities beginning on page F-54.

***Operating Leases.*** Operating leases includes the minimum lease payment obligations associated with our DNE leveraged lease. For additional information, please read Liquidity and Capital Resources Off-Balance Sheet Arrangements DNE Leveraged Lease beginning on page 45. Amounts also include minimum lease payment obligations associated with office and office equipment leases.

In addition, we are party to two charter party agreements relating to VLGCs previously utilized in our global liquids business. The aggregate minimum base commitments of the charter party agreements are approximately $13 million each year for the years 2005 through 2007, and approximately $79 million through lease expiration. The charter party rates payable under the two charter party agreements float in accordance with market based rates for similar shipping services. The $13 million and $79 million numbers set forth above are based on the minimum obligations set forth in the two charter party agreements. The primary term of one charter is through August 2013 while the primary term of the second charter is through August 2014. On January 1, 2003, in connection with the sale of our global liquids business, we sub-chartered both VLGCs to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter agreements. We are currently in negotiations with the owners of the VLGCs and their lenders to obtain a novation and release of our operating subsidiary from the two charter party agreements and partial releases of our parent guarantees. Until such time as the novations and partial releases are granted, we continue to rely on the sub-charters with a subsidiary of Transammonia to satisfy the obligations of our two charter party agreements. To date, the subsidiary of Transammonia has complied with the terms of the sub-charter agreements.

***Capacity Payments.*** Capacity payments include future payments aggregating $2.1 billion under our four remaining power tolling arrangements, including our Gregory tolling arrangement which expires in July 2005, as further described in Item 1. Business Segment Discussion Customer Risk Management beginning on page 18. This amount includes the fixed payments associated with a derivative instrument related to the Independence tolling arrangement, which is reflected at its fair value on our Consolidated Balance Sheets in Risk-Management Liabilities, as well as amounts relating to contracts that are accounted for on an accrual basis. At December 31, 2004, approximately $295 million of fixed payments have been reflected in the fair value of the Independence derivative instrument.

As a result of the Sithe Energies acquisition, which we completed in January 2005, we have reclassified approximately $747 million of our obligations under the Independence tolling arrangement and related derivative instrument as intercompany transactions within our GEN segment beginning February 1, 2005. Although this acquisition transformed the Independence toll and financial derivative instrument into intercompany agreements, those contracts currently remain in effect and we are still obligated to make all fixed capacity payments under those contracts that are reflected in the table above. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion.

In November 2004, we entered into a back-to-back power purchase agreement under which a subsidiary of Constellation Energy receives our rights to capacity and energy under the Kendall tolling arrangement for a four year term expiring effectively in November 2008. Although we are still obligated under the Kendall toll, we will receive approximately $161 million in aggregate cash payments from Constellation to offset our fixed payment obligations under the Kendall toll through November 2008, which payment obligations are reflected in the table above. We paid Constellation $117.5 million in cash in connection with this transaction. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Kendall beginning on page F-25 below for further discussion.

We are exploring opportunities to renegotiate or terminate one or more of our remaining long-term tolling arrangements on terms we consider economical. Please read Results of Operations 2005 Outlook CRM Outlook beginning on page 70 for further discussion of the anticipated effects of these arrangements on our future results of operations.

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In addition, capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $170 million.

***Conditional Purchase Obligations.*** Amounts relate to our co-sourcing agreement with Accenture Ltd. This 10-year agreement runs through 2013 and may be cancelled after two years upon the payment of a termination fee which ranges from $6 million for the first quarter 2005, declining to $2 million through 2013. This termination fee is in addition to amounts due for services provided through the termination date.

***Pension Funding Obligations.*** Amounts include estimated defined benefit pension funding obligations for 2005 ($28 million), 2006 ($19 million) and 2007 ($26 million). Although we expect to incur significant funding obligations subsequent to 2007, such amounts have not been included in this table because our estimates are imprecise.

***Contingent Financial Obligations***

The following table provides a summary of our contingent financial obligations as of December 31, 2004 on an undiscounted basis. These obligations represent contingent obligations that may require a payment of cash upon the occurrence of specified events.

| | Expiration by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 Year | 1-3 Years | 3-5 Years | More than 5 Years |
| | (in millions) | | | | |
| Letters of Credit (1) | $ 94 | $ 94 | $ | $ | $ |
| Surety Bonds (2)(4) | 54 | 54 | | | |
| Guarantees (3) | 4 | | | 4 | |
| Total Financial Commitments | $ 152 | $ 148 | $ | $ 4 | $ |

(1) Amounts include outstanding letters of credit.
(2) Surety bonds are generally on a rolling 12-month basis.
(3) As part of the power purchase agreement with Constellation, under which Constellation effectively receives our rights to purchase approximately 570 MWs of capacity and energy arising from our tolling contract with Kendall, we have guaranteed Constellation the receipt of $3.5 million in reactive power revenues over the four year period of the power purchase agreement. Receipt of these reactive power revenues is predicated on, among other things, filing a reactive power tariff with the FERC.
(4) $40 million of the surety bonds were supported by collateral.

**Off-Balance Sheet Arrangements**

***DNE Leveraged Lease.*** We established our presence in the Northeast region by acquiring the DNE power generating facilities in January 2001 for $950 million.

In May 2001, we entered into an asset-backed sale-leaseback transaction relating to these facilities to provide us with long-term financing for our acquisition. In this transaction, which was structured as a sale-leaseback to minimize our operating cost of the facilities on an after-tax basis and to transfer ownership to the purchaser, we sold for approximately $920 million four of the six generating units comprising these facilities to Danskammer OL LLC and Roseton OL LLC, each of which was newly formed by an unrelated third-party investor, and we concurrently agreed to lease them back from these entities, which we refer to as the owner lessors. The owner lessors used $138 million in equity funding from the unrelated third-party investor to fund a portion of the purchase of the respective facilities. The remaining $800.4 million of the purchase price and the related transaction expenses was derived from proceeds obtained in a private offering of pass-through trust certificates issued by two of our subsidiaries, Dynegy Danskammer, L.L.C. and Dynegy Roseton, L.L.C., who serve as lessees of the applicable facilities. The pass-through trust certificate structure was employed, as it has been in similar financings historically executed in the airline and energy industries, to optimize the cost of financing the assets and to facilitate a capital markets offering of sufficient size to enable the purchase of the lessor notes from the owner lessors. The pass-through trust certificates were sold to qualified institutional buyers in a private offering and the proceeds were used to purchase debt instruments, referred to as lessor notes, from the owner lessors. The lease payments on the facilities support the principal and interest payments on the pass-through trust certificates, which are ultimately secured by a mortgage on the underlying facilities.

As of December 31, 2004, future lease payments are $60 million for 2005 and 2006, $108 million for 2007, $144 million for 2008 and $141 million for 2009, with $919 million in the aggregate due from 2010 through lease expiration. The Roseton lease expires on February 8, 2035 and the Danskammer lease expires on May 8, 2031. We have no option to purchase the leased facilities at the end of their respective lease terms. DHI has guaranteed the lessees payment and performance obligations under their respective leases on a senior unsecured basis. At December 31, 2004, the present value (discounted at 10%) of future lease payments was $771 million.

The following table sets forth our lease expenses and lease payments relating to these facilities for the periods presented.

| | **2004** | **2003** | **2002** |
|---|---|---|---|
| | | **(in millions)** | |
| Lease Expense | $ 50 | $ 50 | $ 50 |
| Lease Payments (Cash Flows) | $ 60 | $ 60 | $ 60 |

If one or more of the leases were to be terminated because of an event of loss, because it had become illegal for the applicable lessee to comply with the lease or because a change in law had made the facility economically or technologically obsolete, DHI would be required to make a termination payment in an amount sufficient to redeem the pass-through trust certificates related to the unit or facility for which the lease was terminated at par plus accrued and unpaid interest. As of December 31, 2004, the termination payment at par would be approximately $1 billion for all of the DNE facilities, which exceeds the $920 million we received on the sale of the facilities. If a termination of this type were to occur with respect to all of the DNE facilities, it would be difficult for DHI to raise sufficient funds to make this termination payment. Alternatively, if one or more of the leases were to be terminated because we determine, for reasons other than as a result of a change in law, that it has become economically or technologically obsolete or that it is no longer useful to our business, DHI must redeem the related pass-through trust certificates at par plus a make-whole premium in an amount equal to the discounted present value of the principal and interest payments still owing on the certificates being redeemed less the unpaid principal amount of such certificates at the time of redemption. For this purpose, the discounted present value would be calculated using a discount rate equal to the yield-to-maturity on the most comparable U.S. treasury security plus 50 basis points.

**Capital Expenditures**

We continue to tightly manage costs and capital expenditures. We had approximately $311 million in capital expenditures during 2004. Our 2004 capital spending by segment was as follows (in millions):

| | |
|---|---|
| GEN | $ 145 |

| | |
|---|---|
| NGL | 61 |
| REG | 92 |
| Other | 13 |
| Total | $ 311 |

Capital spending in our GEN segment primarily consisted of maintenance capital projects, as well as approximately $41 million spent on development capital. Development capital spending primarily related to the

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conversion of our Havana facility to PRB coal. Capital spending in our NGL segment primarily related to maintenance capital projects and wellconnects, as well as approximately $21 million in development capital. Development capital included approximately $13 million for gathering system expansion, additional compression and plant de-bottlenecking in North Texas related to increased gas from the Barnett Shale formation and approximately $8 million for a significant upgrade in compression technology and efficiencies at our Monument gas processing plant. Capital spending in our REG segment primarily related to projects intended to maintain system reliability and new business services.

We expect capital expenditures for 2005 to approximate $279 million. This primarily includes maintenance capital projects, environmental projects, contributions to equity investments and limited GEN and NGL development projects. The capital budget is subject to revision as opportunities arise or circumstances change. Estimated funds budgeted for the aforementioned items by segment in 2005 are as follows (in millions):

| | |
|---|---|
| GEN | $ 190 |
| NGL | 78 |
| Other | 11 |
| Total | $ 279 |

We anticipate increased capital spending in our GEN segment primarily due to an increase in long-term capital maintenance expenditures, including those at our newly acquired Independence facility. We anticipate increased capital spending in the NGL segment primarily due to $6 million for gathering system expansion, additional compression and plant de-bottlenecking in North Texas related to increased gas from the Barnett Shale formation and $20 million for a project under consideration at our Mont Belvieu facility.

As reflected in this section, the capital spending in our NGL segment includes 100% of the expenditures of our consolidated partnerships, Versado Gas Processors, LLC and Cedar Bayou Fractionators, LP. Our ownership percentages of these partnerships are 63% and 88%, respectively, and net funding equal to our ownership percentage is achieved through adjustments to partnership distributions. Adjusted for our partners share of capital expenditures, our expenditures would have been $52 million in 2004 and are expected to be $72 million in 2005.

Our capital expenditures in 2005 and beyond will continue to be limited by negative covenants contained in our debt instruments. These covenants place specific dollar limitations on our ability to incur capital expenditures. Please read Note 11 Debt DHI Term Loan and Credit Facility beginning on page F-43 for further discussion of these limitations. Our long term capital expenditures will also be significantly impacted by the Baldwin consent decree announced in March 2005. If ultimately approved by the Illinois federal district court, this consent decree would obligate us to, among other things, invest $321 million through 2010, and $224 million from 2011 through 2012, respectively, in emission control projects at our Baldwin, Vermilion and Havana plants. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57 for further discussion of this consent decree.

**Financing Trigger Events**

Our debt instruments and other financial obligations include provisions, which, if not met, could require early payment, additional collateral support or similar actions. These trigger events include leverage ratios and other financial covenants, insolvency events, defaults on scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. We do not have any trigger events tied to specified credit ratings or stock price in our debt instruments and are not party to any contracts that require us to issue equity based on credit ratings or other trigger events.

**Commitments and Contingencies**

Please read Note 16 Commitments and Contingencies beginning on page F-55, which is incorporated herein by reference, for a discussion of our commitments and contingencies.

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**Dividends on Preferred and Common Stock**

Dividend payments on our common stock are at the discretion of our Board of Directors. We do not foresee a declaration of dividends in the near term, particularly given our financial condition and the dividend restrictions contained in our financing agreements. We have, however, continued to make the required dividend payments on our outstanding trust preferred securities.

The Series B Preferred Stock issued to ChevronTexaco in November 2001 had no dividend requirement. Because of ChevronTexaco s discounted conversion option, however, we accreted an implied preferred stock dividend over the redemption period, as required by GAAP. Please read Note 12 Related Party Transactions Series B Preferred Stock beginning on page F-47 for further discussion of this non-cash implied dividend and the Series B Exchange. In conjunction with the Series B Exchange, we recognized a gain of approximately $1.2 billion as a preferred stock dividend during 2003.

We accrue dividends on our Series C preferred stock at a rate of 5.5% per annum. We accrued and made dividend payments on the Series C preferred stock during the year ended December 31, 2004 totaling approximately $22 million. Dividends are payable on the Series C preferred stock in February and August of each year, but we may defer payments for up to 10 consecutive semi-annual periods. Please read Note 14 Redeemable Preferred Securities Series C Convertible Preferred Stock beginning on page F-54 for further discussion.

**Internal Liquidity Sources**

Our primary internal liquidity sources are cash flows from operations, cash on hand and available capacity under our $700 million revolving credit facility, which is scheduled to mature in May 2007.

***Current Liquidity.*** The following table summarizes our consolidated revolver capacity and liquidity position at March 4, 2005, December 31, 2004 and December 31, 2003:

| | March 4, 2005 | December 31, 2004 | December 31, 2003 |
|---|---|---|---|
| | | (in millions) | |
| Total Revolver Capacity | $ 700(1) | $ 700(1) | $ 1,100 |
| Outstanding Letters of Credit Under Revolving Credit Facility | (89) | (94) | (188) |
| Unused Revolver Capacity | 611 | 606 | 912 |
| Cash | 365(2) | 628(2) | 477 |
| Total Available Liquidity | $ 976 | $ 1,234 | $ 1,389 |

(1) Please read Note 11 Debt DHI Term Loan and Credit Facility beginning on page F-43 for a discussion of our credit facility.

(2) The March 4, 2005 and December 31, 2004 amounts include approximately $46 million and $47 million, respectively, of cash that remains in Canada and the U.K. that is associated primarily with contingent liabilities relating to our former Canadian and U.K. marketing and trading operations.

***Cash Flows from Operations.*** We had operating cash flows of $5 million in 2004. This consisted of $912 million in operating cash flows from our GEN, NGL and REG segments, reflecting positive earnings for the period offset by reductions in working capital from increased cash collateral postings. The cash flows from our operating segments were substantially offset by $907 million of cash outflows relating to our CRM business and corporate-level expenses. Please read Results of Operations Year Ended 2004 Compared to Year Ended 2003 Operating Income (Loss) beginning on page 56 and Cash Flow Disclosures beginning on page 71 for further discussion of factors impacting our operating cash flows for the periods presented.

For 2005, we have projected operating cash flows of $174 to $189 million. This projection, which is subject to change based on a number of factors, many of which are beyond our control, reflects $640 to $650 million in forecasted operating cash flows from our GEN and NGL business segments, offset by projected cash outflows of $66 million from our CRM business segment and $400 to $395 million in corporate-level expenses, including interest.

Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to tightly manage our operating costs, including costs for fuel and maintenance. With respect to fuel costs, in January 2004, we entered into a new rail transportation contract that reduced the fees associated with fuel procurement at our coal-fired generation facilities in the Midwest; however, these fee reductions were substantially offset by increased coal prices in the Northeast and higher costs associated with the purchase of emission credits. Our ability to achieve fuel-related and other targeted cost savings in the face of industry-wide increases in labor and benefits costs, together with changes in commodity prices, will impact our future operating cash flows. Please read Results of Operations 2005 Outlook GEN Outlook beginning on page 67 for further discussion.

In addition, our CDWR power purchase agreement expired by its terms in December 2004. Please read Item 1. Business Segment Discussion Power Generation beginning on page 2 for a discussion of West Coast Power s current contractual arrangements. Our share of West Coast Power s earnings during 2004 totaled $165 million, excluding impairments of $85 million, approximately 70% of which was derived from the CDWR agreement. In California s current energy market, the West Coast Power generating facilities which previously supported the CDWR contract are significantly less profitable under the RMR contracts or as merchant facilities, and we may consider other alternatives if necessary, including shutting down units if we no longer consider them commercially viable. Based on our ongoing evaluation of strategic alternatives for our West Coast Power assets, we determined that it was not economically feasible to continue to operate our Long Beach generation facility beyond the expiration of the CDWR contract. Therefore, we retired the asset effective January 1, 2005. Please read Results of Operations 2005 Outlook GEN Outlook beginning on page 67 for further discussion of the CDWR agreement and the impairments relating to its expiration.

***Cash on Hand.*** At March 4, 2005 and December 31, 2004, we had cash on hand of $365 million and $628 million, respectively, as compared to $477 million at the end of 2003. This increase in cash on hand at December 31, 2004 as compared to the end of 2003 is primarily attributable to the proceeds from our May 2005 term loan as well as proceeds from assets sales.

***Revolver Capacity***. In May 2004, DHI entered into a new $1.3 billion credit facility, consisting of a $600 million term loan and a $700 million revolving credit facility. This $700 million revolving credit facility, which is scheduled to mature in May 2007, is our primary credit facility. We currently have no drawn amounts under this facility, although as of March 4, 2005, we had $89 million in letters of credit issued under the facility. Our ability to borrow and/or issue letters of credit under a revolving credit facility could become increasingly important to our liquidity and financial condition, particularly if we are unable to generate operating cash flows relative to our substantial debt obligations and ongoing operating requirements. Please read Note 11 Debt DHI Term Loan and Credit Facility beginning on page F-43 for further discussion of our credit facility.

**External Liquidity Sources**

Our primary external liquidity sources are proceeds from asset sales and other types of capital-raising transactions, including potential equity issuances.

***Asset Sale Proceeds.*** In an effort to maximize our return on investment and to further clarify our business strategy, we have sold assets that we do not consider core to our operations, including Illinois Power and our ownership interests in certain non-strategic domestic power generation facilities (e.g., Commonwealth, Hartwell, Joppa, Michigan Power and Oyster Creek) and international power generation facilities (e.g., Costa Rica and Jamaica), as well as our ownership interests in Indian Basin and our Sherman natural gas processing facility. As we have previously disposed of substantially all of our non-core assets, we do not currently anticipate receiving a material amount of proceeds from asset sales, if any, during 2005.

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The aggregate loss of earnings in 2004 associated with these assets (other than Illinois Power) was not material and was more than offset by net gains on sale in 2004. However, beginning in 2005, the lost earnings of approximately $15 million on an annual basis from such assets will no longer be offset by gains on sale.

During 2004, we received aggregate cash proceeds of $576 million from these asset sales, which includes the Illinois Power and Joppa sales proceeds of $316 million, net of transaction costs and cash retained by Illinois Power, but excludes the $100 million deposited by Ameren into escrow, which we expect to receive following approval of the Baldwin consent decree announced in March 2005. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sale of Illinois Power beginning on page F-23 for further discussion of this transaction.

***Capital-Raising Transactions.*** As part of our ongoing efforts to develop a capital structure that is more closely aligned with the cash-generating potential of our asset-based businesses, each of which is subject to cyclical changes in commodity prices, we are continuing to explore additional capital-raising transactions both in the near- and long-term. The timing of any capital-raising transaction may be impacted by unforeseen events, such as legal judgments or regulatory requirements, as well as strategic decisions relating to litigation settlements or contract terminations (including settlement of one or more of our remaining power tolling arrangements), which would necessitate additional capital in the near-term.

These transactions may include capital markets transactions. Our ability to issue public securities is enhanced by our effective shelf registration statement, under which we have approximately $430 million in remaining availability. However, the receptiveness of the capital markets to a public offering cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control. Any issuance of equity likely would have other effects as well, including shareholder dilution. Further, our ability to issue debt securities is limited by our financing agreements, including our credit facility. Please read Note 11 Debt DHI Term Loan and Credit Facility beginning on page F-43 for further discussion.

**Conclusion**

During 2004, we consummated the sale of Illinois Power, which reduced our debt and preferred stock obligations by $1.8 billion and generated $316 million in proceeds, net of transaction costs and cash retained by Illinois Power, excluding the $100 million escrowed funds we expect to receive following approval of the Baldwin consent decree announced in March 2005. We also received approximately $260 million in additional sale proceeds from the disposition of other non-core assets during the period. Further, we extended a significant debt maturity through the replacement of our $1.1 billion revolving credit facility, scheduled to mature in February 2005, with a $700 million revolving credit facility and $600 million term loan scheduled to mature in May 2007 and May 2010, respectively. Using proceeds from the $600 million term loan and the sale of Illinois Power, together with cash on hand, we extinguished some of our substantial debt obligations, including our ABG Gas Supply Financing and ChevronTexaco junior notes.

For the next twelve months, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be positive, but insufficient to satisfy our capital expenditures, debt maturities and interest expenses. However, we believe that our cash on hand and the $100 million deposited into escrow in connection with the sale of Illinois Power, which we expect to receive following approval of the Baldwin consent decree announced in March 2005, together with capacity under our $700 million revolving credit facility, will be sufficient to discharge these obligations. To further our deleveraging efforts, we may consider other capital-raising activities, including potential equity issuances.

Over the longer term and through the anticipated recovery of the U.S. power markets, we expect to maintain sufficient liquidity to satisfy our substantial debt and commercial obligations and provide collateral support through operating cash flows, capacity under our revolving credit facility (or any refinancing thereof), as well as proceeds from anticipated refinancings of debt maturities. Our substantial debt and commercial obligations include increased interest expense, the fixed payment obligations associated with our remaining power tolling

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arrangements in our GEN and CRM businesses (which we expect will continue to reduce our operating cash flows absent early termination or settlement) and counterparty collateral requirements, as well as our significant potential payment obligations relating to our securities litigation and other legal and regulatory matters. We expect that our liquidity position will trend downward as these obligations are satisfied or extinguished.

Our ability to generate operating cash flows will be impacted by a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for power and natural gas, and the success of our ongoing efforts to manage operating costs, particularly fuel requirements, and capital expenditures. Our ability to refinance our substantial debt maturities is primarily dependant upon our ability to generate operating cash flows, which is subject to the factors described in the preceding sentence. Over the longer term we believe that power prices will improve in some or all of the regions in which we operate as the supply-demand imbalance for power decreases. Much of our restructuring work has extended our significant debt maturities to 2007 and beyond, positioning us to benefit from earnings and growth opportunities associated with an expected recovery in the U.S. power markets. Additionally, our NGL business is currently operating in a highly favorable pricing environment. Our future financial condition and results of operations will be materially adversely affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant, prolonged pricing deterioration below price levels experienced over the last few years in our NGL segment.

Our longer term liquidity position and financial condition will also be significantly impacted by the availability of, and our ability to pursue, strategic growth opportunities. However, as indicated above, our desire or ability to pursue any such opportunities is subject to a number of factors beyond our control. As such, we cannot guarantee that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities on our financial condition or results of operations.

Please read   Uncertainty of Forward-Looking Statements and Information   for additional factors that could impact our future operating results and financial condition.

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## RESULTS OF OPERATIONS

***Overview 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 2004, 2003 and 2002. At the end of this section, we have included our 2005 outlook for each segment.

As reflected in this report, we have changed our reporting segments. Prior to 2003, we reported results for the following four business segments: WEN, DMS, T&D and DGC. Beginning January 1, 2003, we have been reporting our operations in the following segments: GEN, NGL, REG and CRM. Other reported results include corporate overhead and our discontinued communications business. All corporate overhead included in other reported results was allocated to our four former reporting segments prior to January 1, 2003. Beginning January 1, 2003, all direct general and administrative expenses and other income (expense) items incurred by us on behalf of our subsidiaries are charged to the applicable subsidiary as incurred. In addition, all interest expense was allocated to our four former reporting segments prior to January 1, 2003.

Prior to January 1, 2003, the GEN and CRM segments were operated together as an asset-based third-party marketing, trading and risk-management business, then referred to as the WEN segment. Please read Note 20 Segment Information beginning on page F-78 for a discussion of the impact of comparing segment results period over period. Regarding our results of operations for 2004, 2003 and 2002, the impact of acquisition and disposition activity reduces the comparability of some of our historical financial and volumetric data. Lastly, recent accounting pronouncements have affected our financial results, particularly those of our CRM business, so as to further reduce the comparability of some of our historical financial data. For example, the rescission of EITF Issue 98-10, effective January 1, 2003, has reduced the number of contracts accounted for on a mark-to-market basis in the 2004 and 2003 periods as compared to the 2002 period. Please read Results of Operations Year Ended 2004 Compared to Year Ended 2003 Cumulative Effect of Change in Accounting Principles beginning on page 61 for further discussion.

***Summary Financial Information.*** The following tables provide summary financial data regarding our consolidated and segmented results of operations for 2004, 2003 and 2002, respectively. The financial data for the years ended December 31, 2003 and 2002 has been restated to reflect the effect of the items described in the Explanatory Note to the accompanying Consolidated Financial Statements. The restatements relate to an increased impairment charge associated with the sale of Illinois Power and our deferred income tax accounts. Please read the Explanatory Note beginning on page F-10 for further discussion of these restatement items.

**Year Ended December 31, 2004**

| | GEN | NGL | REG | CRM | Other and Eliminations | Total |
|---|---|---|---|---|---|---|
| | | | (in millions) | | | |
| Operating income (loss) | $ 163 | $ 287 | $ 139 | $ (118) | $ (279) | $ 192 |
| Earnings from unconsolidated investments | 192 | 10 | | | | 202 |
| Other items, net | 1 | (22) | 3 | (3) | 8 | (13) |
| Interest expense | | | | | | (480) |
| Loss from continuing operations before taxes | | | | | | (99) |
| Income tax benefit | | | | | | 89 |

| | |
|---|---|
| Loss from continuing operations | (10) |
| Loss from discontinued operations, net of taxes | (5) |
| Net income | $ (15) |

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**Year Ended December 31, 2003**

| | GEN | NGL | REG | CRM | Other and Eliminations | Total |
|---|---|---|---|---|---|---|
| | | | | (Restated) (in millions) | | |
| Operating income (loss) | $ 194 | $ 170 | $ (327) | $ (385) | $ (246) | $ (594) |
| Earnings (losses) from unconsolidated investments | 128 | (2) | | (2) | | 124 |
| Other items, net | 4 | (17) | | 31 | 2 | 20 |
| Interest expense | | | | | | (509) |
| Loss from continuing operations before taxes | | | | | | (959) |
| Income tax benefit | | | | | | 246 |
| Loss from continuing operations | | | | | | (713) |
| Loss from discontinued operations, net of taxes | | | | | | (19) |
| Cumulative effect of change in accounting principles, net of taxes | | | | | | 40 |
| Net loss | | | | | | $ (692) |

**Year Ended December 31, 2002**

| | GEN | NGL | REG | CRM | Other and Eliminations | Total |
|---|---|---|---|---|---|---|
| | | | | (Restated) (in millions) | | |
| Operating income (loss) | $ (341) | $ 77 | $ 157 | $ (951) | $ | $ (1,058) |
| Earnings (losses) from unconsolidated investments | (71) | 14 | (2) | (21) | | (80) |
| Other items, net | (20) | (34) | (4) | (49) | | (107) |
| Interest expense | | | | | | (297) |
| Loss from continuing operations before taxes | | | | | | (1,542) |
| Income tax benefit | | | | | | 343 |
| Loss from continuing operations | | | | | | (1,199) |
| Loss from discontinued operations, net of taxes | | | | | | (1,154) |
| Cumulative effect of change in accounting principles, net of taxes | | | | | | (234) |
| Net loss | | | | | | $ (2,587) |

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The following table provides summary segmented operating statistics for 2004, 2003 and 2002, respectively:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| **Power Generation** | | | |
| Million megawatt hours generated gross | 37.1 | 39.1 | 39.8 |
| Million megawatt hours generated net | 35.3 | 37.2 | 37.4 |
| Average natural gas price Henry Hub ($/MMbtu) (1) | $ 5.89 | $ 5.28 | $ 3.35 |
| Average on-peak market power prices ($/MWh) | | | |
| Cinergy | $ 43 | $ 37 | $ 27 |
| Commonwealth Edison | 42 | 37 | 26 |
| Southern | 49 | 41 | 30 |
| New York Zone G | 62 | 61 | 46 |
| ERCOT | 51 | 45 | 29 |
| SP-15 | 55 | 52 | 35 |
| **Natural Gas Liquids** | | | |
| Gross NGL production (MBbls/d): | | | |
| Field plants | 57.3 | 59.6 | 56.0 |
| Straddle plants | 26.6 | 25.6 | 35.9 |
| Total gross NGL production | 83.9 | 85.2 | 91.9 |
| Natural gas (residue) sales (Bbtu/d) | 182.8 | 174.4 | 188.4 |
| Natural gas inlet volumes (MMCFD): | | | |
| Field plants | 535.6 | 591.0 | 569.3 |
| Straddle plants | 990.0 | 1,103.1 | 1,511.9 |
| Total natural gas inlet volumes | 1,525.6 | 1,694.1 | 2,081.2 |
| Fractionation volumes (MBbls/d) | 202.5 | 185.3 | 215.2 |
| Natural gas liquids sold (MBbls/d) | 282.5 | 311.7 | 498.8 |
| Average commodity prices: | | | |
| Crude oil WTI ($/Bbl) | $ 41.43 | $ 31.01 | $ 25.75 |
| Natural gas Henry Hub ($/MMbtu) (2) | $ 6.13 | $ 5.38 | $ 3.22 |
| Natural gas liquids ($/Gal) | $ 0.71 | $ 0.55 | $ 0.40 |
| Fractionation spread ($/MMBtu) daily | $ 2.18 | $ 0.79 | $ 1.13 |
| **Regulated Energy Delivery (5)** | | | |
| Electric sales in KWH (millions) | | | |
| Residential | 4,182 | 5,309 | 5,548 |
| Commercial | 3,389 | 4,413 | 4,415 |
| Industrial | 3,859 | 6,123 | 6,306 |
| Transportation of customer-owned electricity | 2,407 | 2,382 | 2,505 |
| Other | 287 | 374 | 370 |
| Total electric sales | 14,124 | 18,601 | 19,144 |
| Gas sales in Therms (millions) | | | |
| Residential | 214 | 337 | 323 |

| | | | |
|---|---|---|---|
| Commercial | 85 | 145 | 137 |
| Industrial | 40 | 70 | 80 |
| Transportation of customer-owned gas | 171 | 226 | 233 |
| Total gas delivered | 510 | 778 | 773 |
| Cooling degree days Actual (3) | 932 | 980 | 1,467 |
| Cooling degree days 10-year rolling average | 1,236 | 1,214 | 1,246 |
| Heating degree days Actual (4) | 3,145 | 5,256 | 5,118 |
| Heating degree days 10-year rolling average | 3,190 | 4,930 | 5,002 |

(1) Calculated as the average of the daily gas prices for the period.
(2) Calculated as the average of the first of the month prices for the period.

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(3) A Cooling Degree Day (CDD) represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in our region. The CDDs for a period of time are computed by adding the CDDs for each day during the period.
(4) A Heating Degree Day (HDD) represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in our region. The HDDs for a period of time are computed by adding the HDDs for each day during the period.
(5) Operating statistics for REG for the year ended December 31, 2004 only include statistics through September 30, 2004, the date of the sale of Illinois Power to Ameren.

The following tables summarize significant items on a pre-tax basis, with the exception of the 2004 and 2003 tax items, affecting net loss for the periods presented.

| | Year Ended December 31, 2004 | | | | | |
|---|---|---|---|---|---|---|
| | GEN | NGL | REG | CRM | Other | Total |
| | (in millions) | | | | | |
| Discontinued operations | $ | $ 1 | $ | $ 19 | $ 3 | $ 23 |
| Kendall toll restructuring | | | | (115) | | (115) |
| Impairment of West Coast Power | (85) | | | | | (85) |
| Legal and settlement charges | (7) | 2 | (1) | (13) | (92) | (111) |
| Impairment of Illinois Power | | | (54) | | | (54) |
| Loss on sale of Illinois Power | | | (58) | | | (58) |
| Acceleration of financing costs | | | | | (14) | (14) |
| Gas transportation contracts | | | | 88 | | 88 |
| Gain on sale of Joppa | 75 | | | | | 75 |
| Taxes | | | | | 24 | 24 |
| Gain on sale of Indian Basin | | 36 | | | | 36 |
| Gain on sale of Hackberry LNG | | 17 | | | | 17 |
| Gain on sale of Sherman | | 16 | | | | 16 |
| Gain on sale of Oyster Creek | 15 | | | | | 15 |
| Total | $ (2) | $ 72 | $ (113) | $ (21) | $ (79) | $ (143) |

| | Year Ended December 31, 2003 | | | | | |
|---|---|---|---|---|---|---|
| | GEN | NGL | REG | CRM | Other | Total |
| | (in millions) | | | | | |
| Illinois Power goodwill impairment | $ | $ | $ (311) | $ | $ | $ (311) |
| Illinois Power asset impairment | | | (218) | | | (218) |
| Southern Power tolling settlement | | | | (133) | | (133) |
| Sithe power tolling contract | | | | (121) | | (121) |
| Legal charges | | | | | (50) | (50) |
| Batesville tolling settlement | | | | (34) | | (34) |
| Kroger settlement | | | | (30) | | (30) |
| Discontinued operations | | (2) | (3) | (30) | 7 | (28) |
| Impairment of generation investments | (26) | | | | | (26) |
| Acceleration of financing costs | | | | | (24) | (24) |
| West Coast Power goodwill impairment | (20) | | | | | (20) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Impairment of equity investment | | (12) | | | | (12) |
| Taxes | (1) | | | | 34 | 33 |
| Gain on sale of Hackberry LNG | | 25 | | 2 | | 27 |
| Cumulative effect of change in accounting principles | 24 | | (3) | 43 | | 64 |
| Total | $ (23) | $ 11 | $ (535) | $ (303) | $ (33) | $ (883) |

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| | Year Ended December 31, 2002 | | | | | |
|---|---|---|---|---|---|---|
| | GEN | NGL | REG | CRM | Other | Total |
| | | | (in millions) | | | |
| Discontinued operations | $ | $ (37) | $ (561) | $ (51) | $ (854) | $ (1,503) |
| Goodwill impairment | (489) | | | (325) | | (814) |
| Restructuring costs | (42) | (19) | (23) | (73) | | (157) |
| Impairment of generation investments | (144) | | | | | (144) |
| Generation equity earnings (loss) | (50) | | | | | (50) |
| Impairment of technology investments | (5) | (4) | (2) | (20) | | (31) |
| Tolling settlement accrual | | | | (25) | | (25) |
| Illinois Power regulatory asset amortization expense | | | (23) | | | (23) |
| ChevronTexaco contract settlement | | | | (22) | | (22) |
| Enron settlement | (6) | (4) | (2) | (9) | | (21) |
| Other (1) | (23) | (3) | (1) | (37) | | (64) |
| Cumulative effect of change in accounting principle | | | | | (234) | (234) |
| Total | $ (759) | $ (67) | $ (612) | $ (562) | $ (1,088) | $ (3,088) |

(1) Other includes a pre-tax charge of approximately $25 million related to the write-off of our investment in Dynegy*direct* and a pre-tax charge of approximately $14 million associated with the impairment of a generation turbine. These amounts are included in Impairment and other charges. Other also includes various other individually insignificant items.

**Year Ended 2004 Compared to Year Ended 2003**

***Operating Income (Loss)***

Operating income was $192 million in 2004, compared to a loss of $594 million in 2003.

***GEN.*** Operating income for our GEN segment was $163 million in 2004, compared to $194 million in 2003.

In the Midwest region, where we produce approximately 60% of our generated volumes, results increased $27 million year over year. Increased prices contributed an additional $23 million for 2004 compared to 2003. Additionally, we experienced a $28 million reduction in coal transportation costs in the Midwest region, resulting from a transportation contract which took effect at the beginning of 2004. However, improved pricing was partially offset by an increase in operating expenses for the Midwest of approximately $12 million, resulting from the timing of maintenance expenditures, as well as increases in labor costs. Additionally, we reported $17 million less capacity revenue in 2004 as compared with 2003. Volumes were down slightly, from 21.1 million MWh for 2003 to 20.7 million MWh for 2004. This decrease was largely due to reduced production at our Havana facility, resulting from our management of fuel inventories in anticipation of our switch to PRB coal. Please read 2005 Outlook GEN Outlook beginning on page 67 for a discussion of the current fuel and transportation environment.

Improved earnings in the Midwest region were offset by the Northeast region, where results decreased from $49 million in 2003 to $20 million in 2004. This decrease was primarily the result of pricing effects year over year, as increased fuel costs more than offset an increase in power prices. This resulted in a $21 million reduction in earnings. Additionally, we realized $11 million less revenue in 2004 under a transitional power purchase agreement, which expired in October 2004. Operating expense in the Northeast was up $3 million year over year as a result of increased labor and tax expense. However, these reductions in earnings were partially offset by a 7% increase in volumes, which contributed an additional $6 million, largely the result of the dual fuel capabilities of our Roseton unit.

Results in the Southeast region were down $25 million, from $26 million in 2003 to $1 million in 2004. This reduction in earnings was primarily the result of the loss of capacity revenues related to a contract that expired at the end of 2003.

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Results in the ERCOT region decreased $11 million, from a loss of $8 million in 2003 to a loss of $19 million in 2004, primarily as a result of increased natural gas prices and the impact of these increased prices on a long-term power and steam sales contract.

GEN s reported operating income for 2004 also includes approximately $7 million of mark-to-market income related to purchases and sales that did not meet the criteria for hedge accounting under SFAS No. 133 and, therefore, were accounted for on a mark-to-market basis. GEN s results for 2003 include approximately $7 million of mark-to-market income related to derivative contracts that did not qualify as hedges. Mark-to-market income in 2004 included a $3 million charge to earnings in connection with hedge ineffectiveness.

In March 2004, we tested our CoGen Lyondell facility for an impairment based on the identification of a triggering event as defined by SFAS No. 144. After performing this test, we concluded that no impairment was necessary as the estimated undiscounted cash flows exceeded the book value of the asset.

***NGL.*** Operating income for the NGL segment was $287 million in 2004, compared to $170 million in 2003.

The significant improvement in operating income was driven by natural gas, crude oil and natural gas liquids prices, which increased to historically high levels during periods of the year, and a frac spread sufficiently high to make natural gas liquids recovery profitable under all contract settlements during the last five months of 2004. During the entire year, we capitalized on the pricing opportunities presented through strong asset runtime across all NGL segments.

Significantly higher commodity prices contributed approximately $79 million to our results as compared to 2003. Of the increase, $52 million related to POP contracts in field processing, $24 million was derived from our POL contracts at our straddle processing plants and $3 million was generated from natural gas liquids marketing contracts.

Frac spreads were significantly higher in 2004 compared to 2003. During the last five months of 2004, the spread between natural gas liquids prices and natural gas prices reached levels sufficient to support increased liquids recovery industry-wide, reversing an eighteen-month trend. During the year, higher frac spreads generated incremental results of approximately $37 million as compared to 2003. The increase relates to the following: $2 million from additional volumes processed in our Stingray processing plant under economic keep-whole settlement terms; $24 million from contract settlements for existing gas volumes under hybrid contracts that switched from fee to percentage of liquids settlements; and $11 million due to increased industry-wide natural gas liquids recovery which brought additional volumes to our fee-based liquids gathering systems, fractionators, storage and distribution systems and marketing activities.

Gathering and processing operating results increased by $50 million for 2004 compared to 2003, primarily benefiting from 14% higher absolute commodity prices for natural gas and 29% higher absolute commodity prices for natural gas liquids year over year. At our field plants, results increased $42 million. Our current contract portfolio of nearly 99% POP and fee-based contracts benefited from higher prices. However, declines in gross and net natural gas liquids production due to sale of our non-operating joint interest in the Indian Basin plant in April 2004, sale of our Sherman plant in November 2004 and impacts of pipeline, compressor and process unit maintenance at our facilities partially offset the commodity price gains. At our straddle plants, operating results increased $8 million, due largely to the impact of higher natural gas liquids prices under our POL contract settlements. Additionally, during the last five months of 2004, higher frac spreads made it profitable to recover liquids under KW agreements and caused hybrid contracts to switch from fee to POL settlements. The Stingray facility, our only plant that settles under a keep-whole contract structure, operated from the end of July through the remainder of 2004, while it was idled during all of 2003.

Offsetting these increased volumes was the negative impact of Hurricane Ivan on producers volumes available to process at some of our straddle plants that resulted in a reduction in operating results of $17 million. Overall straddle plant inlet volumes decreased 10 % and net barrels produced increased 3%.

Results of our fractionation, storage and terminalling and transportation and logistics businesses increased $13 million for 2004 compared to 2003. Volumes increased at both of our fractionators due to industry-wide

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increased liquids production primarily as a result of higher frac spreads. These higher volumes also drove increased operating income in our supporting storage and natural gas liquids pipeline operations.

Wholesale marketing results were slightly favorable for 2004 compared to 2003 due to the impacts of higher natural gas liquids prices, offset by the loss of a refinery service contract. Results for 2003 benefited from extremely cold weather in the first quarter.

NGL marketing services and distribution results increased approximately $13 million for 2004 compared to 2003. Marketing fees were approximately $3 million higher due to the higher natural gas liquids prices year over year, offset by the impact of lower volumes primarily because of reduced market liquidity. As part of our normal operations, contractual terms with a natural gas liquids pipeline changed, and we terminated an inactive natural gas liquids sales contract. Both of these contractual changes reduced the amount of natural gas liquids volumes required to be held in reserve to serve our customers. Since the volumes held in reserve as deadstock were valued at below current market prices, the release of volumes required to be held in reserve allowed us to recognize an $8 million gain on sales at current market prices. Due to a sharp decline in prices during the last half of December 2004, distribution and marketing services recorded a negative non-cash lower of cost or market adjustment of $4 million compared to a similar negative adjustment of $9 million in 2003, for a positive variance of $5 million year over year.

Operating income for 2004 included pre-tax gains on sales of assets of $69 million, including a $36 million gain associated with the sale of our non-operating interest in the Indian Basin processing plant, a gain of $16 million from the sale of our Sherman processing plant and a $17 million gain on the sale of our final financial interest in our Hackberry LNG project, offset by increased depreciation expense of $6 million due to an adjustment to accumulated depreciation and an asset impairment of $5 million further discussed below. Operating income for 2003 included a $25 million gain on sale of our ownership interest in the Hackberry LNG facility and a $3 million gain associated with the expiration of an environmental indemnity obligation. Please see Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Hackberry LNG Project beginning on page F-26 for further discussion.

In the second quarter 2004, we tested certain of our assets for impairment based on identification of triggering events as defined by SFAS No. 144. After testing, we recorded a pre-tax impairment of $5 million for our Puckett gas treating plant and gathering system due to rapidly depleting reserves associated with that facility. We concluded that no impairment was necessary for any other facilities as estimated undiscounted cash flows exceeded facility book values.

***REG.*** Operating income for the REG segment was $139 million in 2004, which included income prior to our sale of Illinois Power to Ameren on September 30, 2004, compared to a loss of $327 million in 2003. The 2004 period includes a $58 million charge related to the loss on the sale of Illinois Power and a $54 million impairment of Illinois Power assets. We also stopped depreciating our Illinois Power assets on February 1, 2004, as they were classified as held for sale, which resulted in a benefit to operating income of $111 million compared to the 2003 period. The 2003 period includes an operating loss for the fourth quarter 2003 of $485 million, which was not experienced in 2004, due to the September 2004 sale of Illinois Power. Included in the fourth quarter 2003 activity is a $529 million charge for the impairment of goodwill and other assets associated with this segment, as further described in Note 10 Goodwill beginning on page F-41 and $30 million of depreciation expense.

Operationally, residential and commercial electric sales volumes for the first nine months of 2004 were negatively impacted by warmer than average winter weather compared to 2003. Industrial electric sales were negatively affected by customers choosing alternate energy providers. These decreases were more than offset by lower overall operating costs, which were primarily due to the reimbursement of MISO exit fees and RTO development costs totaling approximately $10 million and lower departmental spending, partially offset by higher employee benefit costs. Residential and commercial electric sales volumes were relatively flat in 2004 as compared to 2003 due to cooler summer weather offset by warmer spring weather.

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***CRM.*** Operating loss for the CRM segment was $118 million in 2004, compared to $385 million in 2003.

Results for 2004 were impacted by the following items:

- $88 million gain associated with the exit of four natural gas transportation agreements in support of our third-party marketing and trading business; and

- $115 million charge associated with our entry into a back-to-back power purchase agreement with a subsidiary of Constellation Energy in November 2004 to mitigate the effect of the Kendall tolling arrangement through November 2008.

This segment s results for 2004 also reflect the impact of fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold and include $10 million in gains associated with the mark-to-market value of certain legacy gas contracts which had previously been accounted for on an accrual basis.

Results for 2003 were impacted by the following pre-tax losses:

- $133 million charge associated with the settlement of power tolling arrangements with Southern Power, for which we paid $155 million;

- $121 million mark-to-market loss on contracts associated with the Independence power tolling arrangement;

- $34 million charge associated with the cash settlement of the Batesville tolling arrangement; and

- $30 million charge associated with the settlement of power supply agreements with Kroger, for which we received approximately $110 million.

Additionally, 2003 results include gains from the sale of natural gas inventories of $61 million, offset by charges associated with the settlement of legacy contracts of $21 million and changes in the value of our remaining marketing and trading activity.

***Other.*** Other operating loss was $279 million in 2004, compared to $246 million in 2003. The losses in 2004 and 2003 primarily relate to general and administrative expenses and depreciation and amortization expenses which are incurred at a corporate level. The higher loss in 2004 related primarily to increased legal and settlement charges, costs related to compliance with Section 404 of the Sarbanes-Oxley Act and higher professional fees.

Operating loss for 2004 includes approximately $92 million of expenses related to legal and settlement charges. Please read Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-31 for a discussion of the settlement charges. Operating loss for 2003 includes legal charges of $50 million. The legal charges in both periods resulted from additional activities during each period that affected management s assessment of the probable and estimable loss associated with the applicable proceedings.

***Earnings from Unconsolidated Investments.***

Our earnings from unconsolidated investments were approximately $202 million during 2004 compared to $124 million in 2003. Both the 2004 and 2003 results include significant impairment charges related to these investments, primarily associated with our GEN segment.

***GEN.*** GEN s earnings from unconsolidated investments were approximately $192 million during 2004 compared to $128 million in 2003.

Our West Coast Power investment was the primary driver of equity earnings for the two periods. Total earnings from the investment of $165 million in 2004 were partially offset by an impairment charge of $85 million triggered by the expiration of West Coast Power s CDWR contract, resulting in net earnings of $80 million. Please read Item 1. Business Segment Discussion Power Generation West region Western

Electricity Coordinating Council (WECC) beginning on page 8 for further discussion of West Coast Power s CDWR contract. West Coast Power s equity earnings of approximately $137 million in 2003 were partially offset by a $20 million charge associated with our 50% share of a goodwill impairment charge recorded by West Coast Power in the fourth quarter 2003. Exclusive of impairments, results at our West Coast Power investment improved from 2003 to 2004 primarily as a result of higher realized margins resulting from hedges put in place in connection with the execution of our CDWR contract.

Earnings for 2004 also include gains of $75 million and $15 million on the sales of our 20% interest in the Joppa power generation facility and our 50% interest in the Oyster Creek facility, respectively. In addition to the gain on sale, we reported $5 million of earnings from the Oyster Creek investment. In July 2004, we sold our 50% interest in the Michigan Power generating facility. However, we recorded impairments of approximately $8 million related to the anticipated sale of Michigan Power, which offset our share of Michigan Power s earnings for 2004. The net loss related to Michigan Power recorded in 2004 was $2 million. In September 2004, we sold our 50% interest in the Hartwell facility, resulting in a gain of approximately $2 million. Our 2004 earnings from Hartwell, including this gain, were $4 million. Our 2004 earnings from Commonwealth were approximately $2 million. Our 2004 earnings also included $7 million from our investment in Rocky Road, as well as $5 million from our investment in Black Mountain.

Earnings for 2003 also include a $26 million impairment of U.S. and international investments.

***NGL.*** NGL s earnings from unconsolidated investments were approximately $10 million during 2004 compared to a loss of $2 million in 2003. NGL s 2003 results were negatively impacted by a $12 million pre-tax impairment on our minority investment in GCF related to the difference between our book value and indicative bids received related to the possible sale of our minority investment.

***CRM.*** CRM s losses from unconsolidated investments were zero during 2004 compared to $2 million in 2003. As of December 31, 2003, CRM has no material unconsolidated investments. As such, future results are expected to be immaterial.

***Other Items, Net***

Other items, net consists of other income and expense items, net, minority interest income (expense) and accumulated distributions associated with trust preferred securities. Other items, net totaled $(13) million and $20 million for 2004 and 2003, respectively.

The 2004 results included the following items:

- $25 million minority interest deduction; partially offset by
- $12 million in interest income.

The 2003 results included the following items:

- $17 million in interest income;
- $11 million gain on foreign currency transactions; offset by
- $8 million charge for accumulated distributions associated with trust preferred securities.

***Interest Expense***

Interest expense totaled $480 million for 2004, compared with $509 million for 2003.

The decrease in 2004, as compared to 2003, is primarily attributable to the following:

- Lower average principal balances in the 2004 period (approximately $44 million of the decrease);
- Decreased amortization of debt issuance costs (approximately $28 million of the decrease);

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Lower letter of credit fees (approximately $12 million of the decrease). The lower letter of credit fees resulted from the restructuring of our credit facility in May 2004, with respect to which such fees are lower than those contained in our previous facility.

These items were offset by higher average interest rates on borrowings (approximately $56 million), including the new notes issued in connection with our August 2003 refinancing.

***Income Tax Benefit***

We reported an income tax benefit from continuing operations of $89 million in 2004, compared to an income tax benefit from continuing operations of $246 million in 2003. These amounts reflect effective rates of 90% and 26%, respectively. The 2004 tax benefit includes a $40 million benefit related to a reduction in a deferred tax capital losses valuation allowance associated with gains on asset sales and a $12 million benefit primarily related to IRS and state audits and settlements and other items. The 2003 effective rate was impacted significantly by the $311 million goodwill impairment relating to the REG segment. As there was no tax basis in the goodwill impaired in 2003, there were no tax benefits associated with the charge. Additionally, the 2003 tax benefit includes a $33 million reduction in a valuation allowance associated with our capital loss carryforward as a result of capital gains recognized in 2003 or anticipated to be recognized in early 2004 related to various dispositions. Excluding these items from the 2004 and 2003 calculations would result in effective tax rates of 37% and 33%, respectively. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Please see Note 13 Income Taxes beginning on page F-49 for further discussion of our income taxes.

***Discontinued Operations***

Discontinued operations include Northern Natural in our REG segment, our global liquids business in our NGL segment, our U.K. natural gas storage assets and our U.K. CRM business in the CRM segment and our communications business in Other and Eliminations.

The largest contributor to the pre-tax gain of $23 million ($5 million after-tax loss) for 2004 is the U.K. CRM business, primarily due to $20 million in tax expenses related to the conclusion of prior year tax audits partially offset by translation gains recognized on the repatriation of cash from the U.K. Please read Note 13 Income Taxes beginning on page F-49 for further discussion.

The largest contributor to the pre-tax loss of $28 million ($19 million after-tax) for 2003 is $30 million in pre-tax losses on operations of U.K. CRM and the U.K. natural gas storage assets. This loss is associated with costs relating to our exit from these foreign operations.

***Cumulative Effect of Change in Accounting Principles***

We reflected EITF Issue 02-03 s rescission of EITF Issue 98-10 effective January 1, 2003 as a cumulative effect of change in accounting principle. The net impact was a pre-tax benefit of $33 million ($21 million after-tax), of which a benefit of $43 million was recognized in our CRM segment and a charge of $10 million was recognized in our GEN segment. We also adopted SFAS No. 143 effective January 1, 2003 and recognized a pre-tax benefit of $54 million ($34 million after-tax) associated with its implementation. The $54 million benefit was split between our GEN ($57 million) and REG ($(3) million) segments. Finally, we adopted certain provisions of FIN No. 46R in the fourth quarter 2003 and recognized a pre-tax charge of $23 million ($15 million after-tax) in our GEN segment related to our CoGen Lyondell facility.

Please read Note 2 Accounting Policies beginning on page F-12 for further discussion of our adoption of recent accounting policies.

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**Year Ended 2003 Compared to Year Ended 2002**

*Operating Loss*

Operating loss was $594 million in 2003 and $1,058 million in 2002.

***GEN.*** Operating income for the GEN segment was $194 million in 2003, compared with a loss of $341 million in 2002.

Operating loss for 2002 included the following charges:

- $489 million impairment of goodwill (please see Note 10 Goodwill beginning on page F-41 for further discussion);
- $42 million charge associated with this segment s allocated portion of costs incurred in connection with our corporate restructuring and related work force reductions (please see Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-31 for further discussion);
- $14 million associated with the impairment of a turbine; and
- $6 million associated with fees related to a voluntary action that altered the accounting for certain lease obligations.

Operating income for 2003 included general and administrative expense of $61 million and depreciation and amortization expense of $188 million. In comparison, operating loss for 2002 included general and administrative expense of $66 million and depreciation and amortization expense of $175 million. Please see Other beginning on page 64 for a consolidated discussion of general and administrative expense and depreciation and amortization expense.

Operating income in 2003 included a $34 million benefit related to pricing and a $51 million benefit due to generated volumes versus 2002. GEN s results for 2003 reflect higher power prices on average as compared to 2002. This was primarily driven by higher demand in the Midwest and Northeast regions given colder than expected weather conditions during the first half of 2003. Average on-peak prices in the Midwest and Northeast regions during 2003 increased 39% and 33%, respectively, from the corresponding prices for 2002. The earnings from our peaking generation facilities, which include both capacity and energy sales, were unfavorably impacted by compressed natural gas spark spreads and overcapacity in the generation marketplace. Overall, volumes remained relatively flat to 2002; however, the net MWh in the Midwest and Northeast were 21.1 million and 5.7 million, respectively, for 2003 compared to 20.4 million and 3.6 million, respectively, for 2002.

Operating loss for 2002 included approximately $30 million associated with favorable fuel supply contracts that expired in 2002. Additionally, revenues associated with the DNE facilities decreased approximately $20 million in 2003 as compared to 2002. This decrease primarily reflects reduced income recognized through amortization of a liability established for a transitional power purchase agreement acquired from the seller of the DNE facilities as part of their acquisition, which agreement expired in October 2004. Finally, 2003 operating income included an $11 million charge related to a comprehensive settlement agreement with a manufacturer of turbines in which we agreed in principle to forfeit a prepayment in the amount of $11 million.

GEN s reported operating income for the 2003 and 2002 periods included approximately $7 million and $8 million, respectively, of mark-to-market income related to derivative contracts that did not qualify as hedges.

In December 2003, we tested certain 100% owned assets for impairment in accordance with SFAS No. 144, based on the identification of certain trigger events. These triggers indicated that our Bluegrass, Calcasieu, Riverside, Rockingham and Rolling Hills peaking facilities could be impaired due to decreased spark spreads and other market factors. After performing these tests, we concluded that no impairment was necessary as the estimated undiscounted cash flows exceeded the book value of the respective asset.

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Operating loss for 2002 reflects the sale to our CRM segment of the fair value of GEN s generation capacity, forward sales and related trading positions at an internally determined transfer price. For 2003, operating income for the GEN segment reflects the sale of power to third parties at market prices.

***NGL.*** Operating income for the NGL segment was $170 million in 2003, compared to $77 million in 2002. Operating income for 2003 included general and administrative expense of $37 million and depreciation and amortization expense of $81 million. 2003 operating income also included a $25 million gain associated with the sale of our Hackberry LNG project. Please see Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Termination Hackberry LNG Project beginning on page F-26 for further discussion. Operating income for 2002 included $19 million in charges relating to this segment s allocated portion of costs incurred in connection with our corporate restructuring and related work force reductions, as well as general and administrative expense of $36 million and depreciation and amortization expense of $88 million. Please see Other beginning on page 64 for a consolidated discussion of general and administrative expense and depreciation and amortization expense.

The increase in operating income in 2003 as compared to 2002 relates primarily to the upstream business. For 2003 we experienced higher natural gas and natural gas liquids prices, which resulted in a significant increase in processing plant margins at our field plants. In addition to favorable pricing, volumes of natural gas liquids produced at our field plants were 6% higher in 2003 as compared to 2002. This was primarily due to increased production in the highly active drilling area in North Texas. Our 2003 straddle plant volumes were much lower as compared to 2002 because of the low frac spread for 2003, which resulted in our decision to by-pass unprofitable gas or to shut-down some of our plants that are subject to significant frac spread risk and whose contract mix is substantially made up of KW contracts.

In our downstream business, volumes available for fractionation declined to 185 MBbls in 2003 compared to 215 MBbls per day in 2002 as a direct result of reduced natural gas liquids recovery from both our own and from third-party gas processing plants due to the low frac spread. Additionally, some of our competitors recent expansion of Mont Belvieu area fractionation capacity beyond the availability of raw natural gas liquids supplies has increased competition for supplies, leading to lower fees charged for fractionation service in the area.

In our wholesale marketing operations, profits were higher due to margin increases resulting from weather-driven propane sales in the first quarter of 2003 and the impact of higher commodity prices on contracts where we retain a percentage of the sales price as our fee for marketing natural gas liquids on behalf of others, such as in our refinery services agreements and our natural gas liquids marketing agreements with ChevronTexaco. NGL s marketing results declined from prior period levels as a result of reduced overall market liquidity and customer concerns relating to our liquidity and non-investment grade credit status. Finally, downstream operating income for 2002 included income of approximately $18 million related to our Canadian crude business, which was sold in August 2002. Although our marketed volumes declined from approximately 498,800 barrels per day in 2002 to approximately 311,700 barrels per day during 2003 due to reduced domestic marketing opportunities and the divestiture of our global liquids business, effective January 1, 2003, this decline had little impact on our operating income, as the financial impact of our global liquids business is included in discontinued operations for all periods presented. The global liquids business sold an average of 95,500 barrels per day in 2002.

***REG.*** Operating loss for the REG segment was $327 million in 2003, compared to operating income of $157 million in 2002.

Operating loss for 2003 included a $529 million charge for the impairment of goodwill and other assets associated with this segment, as further described in Note 10 Goodwill beginning on page F-41, as well as general and administrative expense of $68 million and depreciation and amortization expense of $121 million. Operating income for 2002 included restructuring charges of $23 million, as well as general and administrative expense of $67 million and depreciation and amortization expense of $175 million. Please see Other beginning on page 64 for a consolidated discussion of general and administrative expense and depreciation and amortization expense.

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We were negatively impacted in 2003 as compared to 2002 by cooler than normal spring and summer weather partially offset by colder than normal winter weather, which caused net decreases in residential and commercial electricity sales volumes and increases in residential and commercial gas sales volumes. Additionally, revenues during 2003 and 2002 attributable to the sale of electricity to residential customers were negatively impacted by a 5% rate reduction effective in May 2002.

***CRM.*** Operating loss for the CRM segment was $385 million in 2003 compared to $951 million in 2002.

Results for 2003 were impacted by the following pre-tax losses:

- $133 million charge associated with the settlement of power tolling arrangements with Southern Power, for which we paid $155 million;
- $121 million mark-to-market loss on contracts associated with the Independence power tolling arrangement;
- $34 million charge associated with the cash settlement of the Batesville tolling arrangement; and
- $30 million charge associated with the settlement of power supply agreements with Kroger, for which we received approximately $110 million.

In addition, 2003 results include losses associated with fixed payments on power tolling arrangements in excess of realized margins on power generated and sold pursuant to these arrangements. These items were offset by gains totaling approximately $61 million associated with sales of natural gas in storage which had previously been recorded at fair value, partially offset by $21 million of charges associated with settlements of legacy contracts. Please read Note 2 Accounting Policies Revenue Recognition beginning on page F-17 for additional details.

Results for 2002 were impacted by the following items:

- $325 million charge for the impairment of goodwill (for further information, please see Note 10 Goodwill beginning on page F-41);
- $73 million in costs associated with our corporate restructuring and related work force reductions (for further information, please see Note 4 Restructuring and Impairment Charges Severance and Other Restructuring Costs beginning on page F-31);
- $25 million in charges associated with the settlement of tolling contracts;
- $25 million in charges associated with the write-off of our investment in Dynegy*direct*; and

$7 million in losses associated with the sale of our Canadian physical gas business to Seminole.

In addition, 2002 results included general and administrative expense of $154 million and depreciation and amortization expense of $28 million. Please see  Other  below for a consolidated discussion of general and administrative expense and depreciation and amortization expense. Finally, 2002 results were negatively impacted by reduced gas marketing volumes as a result of reduced market liquidity and our lower credit ratings.

During 2002, our CRM segment was actively managed as part of our ongoing strategy and its results included, in part, settlement with third parties of physical power and other trading positions purchased from our GEN segment at an internally determined transfer price. Please read Note 20 Segment Information beginning on page F-78 for further discussion.

***Other.*** Other operating loss was $246 million in 2003, compared to zero in 2002. The loss in 2003 primarily relates to general and administrative expenses and depreciation and amortization expenses which are incurred at a corporate level. Prior to 2003, these costs were allocated to the segments.

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Consolidated general and administrative expenses were $346 million in 2003, compared to $325 million in 2002. The $21 million increase year over year is principally the result of the $50 million second quarter 2003 litigation reserve and higher professional fees, offset by significantly lower compensation costs in the 2003 period resulting from the work force reductions.

Consolidated depreciation and amortization expenses were $454 million in 2003, compared to $466 million in 2002. The $12 million decrease year over year is primarily due to reduced depreciation in our REG segment, offset by increased depreciation of generation assets due to an increased asset base. Increases in our asset base include the construction of the Renaissance, Bluegrass and Foothills facilities in 2002 and the completion of Rolling Hills in 2003.

***Earnings (Losses) from Unconsolidated Investments***

Our earnings from unconsolidated investments were approximately $124 million during 2003 compared to losses of $80 million in 2002. Both 2002 and 2003 results include significant impairment charges related to these investments, primarily associated with the GEN segment.

***GEN.*** GEN s earnings from unconsolidated investments were approximately $128 million during 2003 compared to a loss of $71 million in 2002.

Our West Coast Power investment was the primary driver of equity earnings for both periods. West Coast Power provided earnings of $117 million in 2003 compared to $17 million in 2002. Earnings for 2003 include a $20 million charge associated with our 50% share of a goodwill impairment charge recorded by West Coast Power in the fourth quarter 2003. Earnings for 2002 include a $50 million charge associated with our 50% share of a bad debt allowance recognized by West Coast Power, as well as a $33 million charge to write down our investment to fair value. Exclusive of these items, West Coast Power s improved results from 2002 to 2003 were driven by increased earnings under the CDWR contract.

In 2003, we recorded a $26 million impairment of our investments in Panama, Jamaica, Michigan Power, Commonwealth and Black Mountain, because of our determination that current market value was less than the book values of the investments. In 2002, we recorded a $144 million impairment of U.S. investments, of which $33 million related to West Coast Power, as discussed above. We assessed the carrying value of our generation portfolio on an asset-by-asset basis and determined that the fair value of some of our U.S. investments was less than our book value. The diminution in the fair value of these investments was primarily a result of depressed energy prices.

***NGL.*** NGL s losses from unconsolidated investments were approximately $2 million during 2003 compared to earnings from unconsolidated investments of $14 million in 2002. NGL s 2003 results were negatively impacted by a $12 million pre-tax impairment on our minority investment in GCF related to the difference between our book value and indicative bids received related to the possible sale of our minority investment. In addition, WTLPS, which we sold to ChevronTexaco in August 2002, contributed approximately $6 million to our results for 2002.

***CRM.*** CRM s losses from unconsolidated investments were $2 million during 2003 compared to $21 million in 2002. As of December 31, 2003, CRM had no material unconsolidated investments. As such, future results are expected to be immaterial. The 2002 loss is primarily comprised of charges allocated to the CRM segment for impairments associated with technology investments.

***Other Items, Net***

Other items, net consists of other income and expense items, net, minority interest income (expense) and accumulated distributions associated with trust preferred securities. Other items, net totaled $20 million and $(107) million for 2003 and 2002, respectively.

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The 2003 results included the following items:

- $17 million in interest income;
- $11 million gain on foreign currency transactions; offset by
- $8 million charge for accumulated distributions associated with trust preferred securities.

The 2002 results included the following items:

- $36 million in interest income;
- $36 million minority interest deduction, primarily related to ABG Gas Supply and Black Thunder;
- $22 million charge relating to the cancellation of our natural gas purchases and sales contract with ChevronTexaco;
- $21 million charge associated with the settlement of the Enron litigation relating to the termination of our proposed merger;
- $12 million charge for accumulated distributions associated with trust preferred securities;
- $10 million charge primarily related to our settlements with the CFTC ($4 million) and SEC ($3 million); and
- Remaining amounts consisting of individually insignificant items.

***Interest Expense***

Interest expense totaled $509 million for 2003, compared with $297 million for 2002. The significant increase in 2003, as compared to 2002, is primarily attributable to the following:

- Higher average interest rates on borrowings (approximately $70 million of the increase), including Illinois Power s new mortgage bonds and the new notes issued in connection with our August 2003 refinancing;

Interest expense for 2002 does not include approximately $65 million of interest expense which was allocated to our discontinued businesses;

Higher average principal balances in the 2003 period (approximately $30 million of the increase);

Increased amortization of debt issuance costs (approximately $35 million of the increase, of which approximately $24 million relates to accelerated amortization of previously incurred financing costs and the settlement value of the associated interest rate hedge instruments); and

Higher letter of credit fees (approximately $15 million of the increase). The higher letter of credit fees resulted from the restructuring of our credit facility in April 2003, with respect to which such fees are higher than those contained in our previous facility.

***Income Tax Benefit***

We reported an income tax benefit from continuing operations of $246 million in 2003, compared to an income tax benefit from continuing operations of $343 million in 2002. These amounts reflect effective rates of 26% and 22%, respectively. The effective rates were impacted significantly by the $311 million goodwill impairment relating to the REG segment in 2003 and the $814 million goodwill impairment relating the CRM and GEN segments in 2002. As there was no tax basis in the goodwill impaired in 2003 or $579 million of the goodwill impaired in 2002, there were no tax benefits associated with the charges. Additionally, the 2003 tax benefit includes a $33 million reduction in a valuation allowance associated with our capital loss carryforward as a result of capital gains recognized in 2003 or anticipated to be recognized in early 2004 related to various dispositions. Excluding these items from the 2003 and 2002 calculations would result in effective tax rates of

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33% in 2003 and 36% in 2002. In general, differences between these adjusted effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax basis differences.

Please see Note 13 Income Taxes beginning on page F-49 for further discussion of our income taxes.

***Discontinued Operations***

Discontinued operations include Northern Natural in our REG segment, our global liquids business in the NGL segment, our U.K. natural gas storage assets and our U.K. CRM business in the CRM segment and our communications business in Other and Eliminations.

The largest contributor to the pre-tax loss of $28 million ($19 million after-tax) for 2003 is $30 million in pre-tax losses on operations of U.K. CRM and the U.K. natural gas storage assets. This loss is associated with costs relating to our exit from these foreign operations.

During 2002, the $1,503 million pre-tax loss ($1,154 million after-tax) from discontinued operations was primarily comprised of $854 million in pre-tax losses ($538 million after-tax) from the global communications business and $561 million in pre-tax losses ($538 million after-tax) from Northern Natural. The global communications business recorded pre-tax charges of $635 million for the impairment of communications assets. The remaining $219 million in losses is related to approximately $48 million of impairments of technology investments and carrying costs associated with the business. In August 2002, we sold Northern Natural to MidAmerican and incurred a pre-tax loss of approximately $599 million associated with the sale. We recorded a valuation allowance against a portion of the tax benefit resulting from the sale, due to uncertainty as to the ability to generate capital gains in the future. Discontinued operations for the REG segment in 2002 also includes $38 million in pre-tax earnings associated with operating results from Northern Natural prior to its sale. The CRM pre-tax loss of $51 million ($49 million after-tax) consisted of $115 million in losses associated with the U.K. CRM business offset by $64 million in income from our U.K. natural gas storage assets. The global liquids pre-tax loss of $37 million ($29 million after-tax) included a pre-tax charge of approximately $12 million associated with the impairment of an LPG investment in the global liquids business. The remaining $25 million loss related to the write-off of a logistics and accounting computer system and other costs associated with the wind-down of the business.

***Cumulative Effect of Change in Accounting Principles***

We reflected EITF Issue 02-03 s rescission of EITF Issue 98-10 effective January 1, 2003 as a cumulative effect of a change in accounting principle. The net impact was a pre-tax benefit of $33 million ($21 million after-tax), of which a benefit of $43 million was recognized in our CRM segment and a charge of $10 million was recognized in our GEN segment. We also adopted SFAS No. 143 effective January 1, 2003 and recognized a pre-tax benefit of $54 million ($34 million after-tax) associated with its implementation. The $54 million benefit was split between our GEN ($57 million) and REG ($(3) million) segments. Finally, we adopted certain provisions of FIN No. 46R in the fourth quarter 2003 and recognized a pre-tax charge of $23 million ($15 million after-tax) in our GEN segment related to our CoGen Lyondell facility.

On January 1, 2002, we adopted SFAS No. 142. In connection with its adoption, we realized a cumulative effect loss of approximately $234 million associated with a write-down of goodwill associated with our discontinued communications business.

***2005 Outlook***

The following summarizes our 2005 outlook for our three remaining reportable segments.

***GEN Outlook.*** We expect that this segment s future financial results will continue to reflect sensitivity to commodity prices and weather conditions. We will continue our efforts to manage price risk through the

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optimization of fuel procurement and the marketing of power generated from our assets, including through forward sales and related transactions, consistent with our views on market recovery in the regions we serve. Our sensitivity to commodity prices and our ability to manage this sensitivity is subject to a number of factors, including general market liquidity, particularly in forward years, our ability to provide necessary collateral support and the willingness of counterparties to transact business with us given our non-investment grade credit ratings. Additionally, because we may seek to manage price risk through forward sales and related transactions, at times we may be unable to capture opportunities presented by rising prices.

The operation of our generation facilities is highly dependent on our ability to procure coal as a fuel. Power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. Our long-term supply and transportation agreements for our Midwest fleet mitigate these concerns. In the Northeast, we have accumulated sufficient inventories to allow us to operate our assets. While we believe our physical inventories and contractual commitments provide us with a stable fuel supply, we are subject to physical delivery risks outside of our control.

As discussed in Item 1. Business Segment Discussion Power Generation beginning on page 2, we enter into sales of capacity from our generation assets, which provide a revenue stream independent of energy sales. During 2004, we have seen increases in the market for capacity-related products from our peaking and intermediate generation facilities.

Throughout 2004, a substantial portion of our operating margin and earnings from unconsolidated investments was under contract or hedged. The primary contracts included the CDWR contract held by West Coast Power and the Illinois Power power purchase agreement, both of which terminated in December 2004. Our future results of operations will be significantly impacted by the expiration of the CDWR contract. West Coast Power, whose equity earnings were primarily derived from the CDWR contract, has been our largest contributor to earnings from unconsolidated investments. As a result of the expiration of the CDWR contract, future earnings from the investment will be substantially reduced. Please read Item 1. Business Segment Discussion Power Generation beginning on page 2 for a discussion of West Coast Power s current contractual arrangements. Based on our ongoing evaluation of strategic alternatives for our West Coast Power assets, we determined that it was not economically feasible to continue to operate our Long Beach generation facility beyond the expiration of the CDWR contract. Therefore, we retired the asset as of January 1, 2005. Additionally, the expiration of the CDWR contract in December 2004 had a negative impact on the fair value of our investment in West Coast Power. As a result, we recorded an impairment of $73 million in 2004. Our 2004 equity earnings also included a charge of $12 million, representing our 50% share of West Coast Power s impairment of certain generation assets. This impairment was also triggered by the expiration of the CDWR contract. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings FERC and Related Regulatory Investigations Request for Refunds beginning on page F-59 for further discussion of the legal challenges to the CDWR contract. Please also read Liquidity and Capital Resources Internal Liquidity Sources Cash Flows from Operations beginning on page 48 for a discussion of our efforts to seek a replacement of the CDWR contract.

Our former power purchase agreement between DMG and Illinois Power terminated in December 2004. In September 2004, in connection with the sale of Illinois Power to Ameren, DPM entered into a new two-year power purchase agreement with Illinois Power with expected volumes comparable to the former agreement. Under the terms of this new agreement, which became effective January 1, 2005, we have agreed to provide Illinois Power with up to 2,800 MWs of capacity at $48.00 per kW-yr and up to 11.5 million MWh of energy each year at a fixed price of $30 per MWh. Under the new agreement, we are no longer the provider of last resort for Illinois Power, which exposed us to volume and price uncertainties under the former agreement. Under the former agreement, we received contract revenues based on a higher fixed capacity payment and lower variable energy payments. Accordingly, GEN s operating income under the new agreement will be impacted more significantly by deviations from expected energy purchases by Illinois Power. We expect that any reduction in operating income under this new agreement will be mitigated by no longer serving as the provider of last resort.

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During 2004, we sold our 50% interests in the Oyster Creek, Michigan Power, Hartwell, and Commonwealth facilities, as well as our 20% interest in the Joppa facility. Additionally, we sold our 100% interest in Plantas Eolicas, S.A. de C.V. (Costa Rica) and 17.55% interest in Jamaica Energy Partners. Our 2004 results include an aggregate $99 million of earnings from these investments, including $82 million of net gains on sales. For 2003, these investments contributed $17 million to earnings. However, beginning in 2005, the lost earnings from these assets will no longer be offset by gains on sale.

On January 31, 2005, we acquired the 1,021 MW, combined-cycle Independence power generation facility, four natural gas-fired merchant facilities in New York and four hydroelectric generation facilities in Pennsylvania. GEN s 2005 results will include the results of this acquisition, including general and administrative costs associated with Sithe Energies New York City office, until such time as those costs can be mitigated. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion of this transaction.

***NGL Outlook.*** The financial outlook for our NGL segment is sensitive to natural gas and natural gas liquids prices. The pricing environment for 2005 is expected to be strong with high volatility for commodities driving our market, similar to 2004, when we experienced high volatility in both natural gas and natural gas liquids prices. Provided the strong pricing environment persists throughout 2005, our upstream contract settlements under POP and POL contracts will continue to benefit. However, high natural gas prices without a comparable upward movement in natural gas liquids prices would reduce frac spreads to levels where it is no longer profitable to extract natural gas liquids. If frac spreads are reduced to unprofitable levels, our hybrid contracts, sensitive to frac spreads, will switch from POL settlements to fee settlements, which would negatively impact our earnings in a high natural gas liquids price environment. Frac spread volatility will impact natural gas liquids volumes produced from our own and third party natural gas processing plants as frac spread economics either do or do not support natural gas liquids extraction. In 2005, the U.S. and world economies are expected to grow, though not as rapidly as 2004. This growth will continue to support demand for products from the petrochemical industry, which experienced a dramatic improvement in 2004. The industry s improvement was due in part to strong world-wide ethylene and propylene demand, driving higher natural gas liquids feedstock consumption, and helping to improve frac spreads. This increased demand for natural gas liquids feedstocks will continue to benefit our results.

There seems to be a widely held belief that, long term, natural gas prices will remain high enough relative to natural gas liquids prices to depress the frac spread below levels required for liquids extraction, reducing natural gas liquid volumes requiring fractionation. As a result, there remains aggressive competition between fractionators for available volumes, driving fees paid for fractionation services to historic lows. In October 2004, we lost a substantial fractionation customer at our Mont Belvieu fractionator when the previous contract reached the end of its primary term. The customer had committed the volumes to a competitor as part of a larger asset sale. We continue to aggressively compete for replacement volumes albeit in a highly competitive market.

Straddle plant gas processing will continue to be impacted by uncertainty surrounding natural gas quality specifications for liquefiable hydrocarbons. Other than occasional short-term periods of favorable natural gas liquids extraction economics, market conditions for straddle plant gas processing have been generally poor since late 2000. Pipeline companies have operational and safety concerns related to the heavier natural gas liquids, like butane and natural gasoline, that are left in the natural gas entering their systems instead of being extracted. While industry stakeholders respond to recent FERC decisions directing pipeline companies to address this issue in their tariff, there is a lack of clarity around when and where processing is required, especially during periods of poor extraction economics. The result is a patchwork of pipeline policies and practices that leave producers and processors without clearly defined ground rules, making contracting gas supply and planning straddle plant operations difficult. Resolution of the issue is currently being pursued through the Natural Gas Council, FERC and other affected stakeholders.

Drilling for natural gas throughout our core processing areas in New Mexico, West Texas, North Texas and offshore Louisiana continues to increase, consistent with natural gas prices that have averaged $6/MMBtu.

Continued exploration and production at these commodity price levels will benefit our upstream business by providing additional volumes for gathering and processing. In the Permian, continued property sales by major exploration and production companies to smaller independent producers will contribute to increased activity and exploration. If natural gas prices were to decline significantly in the future, resulting in reduced drilling activities, this segment s results could be adversely affected.

While we have not experienced significant turnover in customer contracts as a result of our non-investment grade credit ratings, we have been required to provide collateral or other adequate assurance of our obligations in connection with many of our commercial relationships. On occasion, we have been unable to satisfy efficiently a potential new customer s concerns about our credit ratings. We expect similar collateral requirements until such time as our credit ratings measurably improve.

At this time it is our strategy to not sell forward future natural gas liquids production; however, any change in this strategy resulting in a desire to hedge future natural gas liquids production during 2005 may again be limited by reduced market liquidity and our obligation to post collateral. As commodity prices rise, we are required by counterparties to post additional collateral.

We intend to continue prudently expanding our North Texas gathering system, working collaboratively with our producer customers. Additional compression and pipeline reach along with plant debottlenecking are expected to add volumes to our expanded Chico gas processing plant In addition, we continue to review our asset portfolio to maximize return on investment. In 2004, we identified and sold several assets that were not strategic to our core operations, including our final financial interest in Hackberry LNG, our interest in the Indian Basin plant and our Sherman facility. We may pursue sale of other assets if the price is sufficient to mitigate the anticipated impact on future earnings. Please see Liquidity and Capital Resources External Liquidity Sources Asset Sale Proceeds beginning on page 49 for further discussion.

***CRM Outlook.*** Our CRM business future results of operations will be significantly impacted by our ability to complete our exit from this business. During 2004, we were successful in reaching agreements to exit four of our natural gas transportation agreements. In November 2004, we entered into a back-to-back power purchase agreement with a subsidiary of Constellation, under which we will receive $161 million in payments through November 2008 to offset our fixed payment obligations under our Kendall tolling arrangement, while positioning us to take advantage of the market recovery expected in 2008 and beyond. In January 2005, we completed the purchase from Exelon Corporation of all of the outstanding capital stock of ExRes SHC, Inc., the parent company of Sithe Energies and Independence. Please read Note 3 Acquisitions, Dispositions, Contract Terminations and Discontinued Operations Acquisitions Sithe Energies beginning on page F-23 for further discussion. As a result of this agreement, our Independence power tolling arrangement has been transformed into an intercompany agreement under our GEN segment, which now includes the Independence facility. This substantially eliminates its future financial statement impact. Our Gregory tolling arrangement expires by its terms in July 2005.

Our Sterlington tolling arrangement remains in place through 2017. We are exploring opportunities to assign or renegotiate the terms of this arrangement, but we cannot guarantee that we will be successful. If we do not renegotiate or terminate this remaining arrangement, it will continue to impact negatively our near- and long-term earnings and cash flows based on the current pricing environment. Any renegotiation or termination of this long-term contract would likely result in significant cash payments and a charge to earnings in the applicable period. For a discussion of our annual and long-term obligations under these arrangements, please read Disclosure of Contractual Obligations and Contingent Financial Commitments beginning on page 43 and Item 1. Business Segment Discussion Customer Risk Management beginning on page 18.

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**CASH FLOW DISCLOSURES**

The following tables include data from the operating section of the consolidated statements of cash flows and include cash flows from our discontinued operations, which are disclosed on a net basis in loss on discontinued operations, net of tax, in the consolidated statements of operations:

| | GEN | NGL | REG | CRM | Other & Eliminations | Consolidated |
|---|---|---|---|---|---|---|
| | | | | (in millions) | | |
| Year Ended December 31, 2004 | $ 421 | $ 278 | $ 213 | $ (371) | $ (536) | $ 5 |
| Year Ended December 31, 2003 | $ 428 | $ 186 | $ 67 | $ 496 | $ (301) | $ 876 |
| Year Ended December 31, 2002 | $ 258 | $ 24 | $ 262 | $ (318) | $ (251) | $ (25) |

***Operating Cash Flow.*** Our cash flow provided by operations totaled $5 million for the 12 months ended December 31, 2004. During the period, our GEN, NGL and REG segments provided positive cash flow from operations. GEN provided cash flow from operations of $421 million due primarily to positive earnings for the period and increased business activity, partially offset by increased cash collateral posted in lieu of letters of credit; NGL provided cash flow from operations of $278 million due primarily to positive earnings, partially offset by increased prepayments due to higher sales; and REG provided cash flow from operations of $213 million due primarily to positive earnings for the period. Our CRM segment used approximately $371 million in cash due primarily to fixed payments associated with the power tolling arrangements and related gas transportation agreements, a $117.5 million payment related to the restructuring of the Kendall toll, increased cash collateral posted in lieu of letters of credit and our exit from four long-term natural gas transportation contracts. Other & Eliminations includes a use of approximately $536 million in cash due primarily to interest payments to service debt, settlement payments and general and administrative expenses.

Cash provided in 2003 primarily relates to collateral returns, settlements of risk management assets and sales of natural gas storage in excess of $500 million from our CRM business, a $110 million income tax refund and solid operational performances from our GEN, NGL and REG segments. Despite a relatively weak commodity price environment, our GEN segment provided cash flows in excess of $400 million largely due to effective commercial and operational management and our coal- and dual-fired generation assets. Similarly, our NGL segment contributed cash flows from operations in excess of $180 million due to a strong commodity price environment, particularly in the upstream business, offset by increases in prepayments and lower downstream results due to industry-wide reductions in volumes available for fractionation. Our REG segment contributed operating cash flows in excess of $60 million, primarily from normal operating conditions, offset by working capital outflows due to increased injection of gas into storage, as well as an increase in prepayments. General and administrative costs, a $45 million litigation settlement and continued extinguishment of liabilities during our exit from our communications business offset these positive operational cash flows during 2003.

For 2002, our cash flow used in operations was $25 million. When compared to 2003, the primary driver of our operating cash outflows was our required posting during 2002 of significant amounts of collateral under the terms of our CRM commercial contracts due to the degradation of our credit ratings.

***Capital Expenditures and Investing Activities.*** Net cash provided by investing activities during 2004 totaled $262 million. Capital spending of $311 million was comprised primarily of $145 million, $61 million and $92 million in the GEN, NGL and REG segments, respectively. The capital spending for our GEN segment related primarily to maintenance capital projects, as well as approximately $41 million related to developmental projects. Capital spending in our NGL segment related primarily to maintenance capital projects and wellconnects, as well as approximately $21 million on developmental projects. Capital spending in our REG segment related primarily to projects intended to maintain system reliability and new business services.

Net cash proceeds from asset sales of $576 million consisted of the following items:

- $217 million from the sale of Illinois Power, net of cash retained by Illinois Power of $52 million;
- $152 million from the sale of our equity investments in the Oyster Creek, Hartwell, Michigan Power, Jamaica and Commonwealth generating facilities;
- $99 million from the sale of Joppa;
- $48 million from the sale of Indian Basin;
- $34 million from the sale of Sherman;
- $17 million from the sale of our remaining financial interest in the Hackberry LNG project; and
- $9 million from the sale of PESA.

The cash proceeds were partially offset by $3 million of capitalized business acquisition costs incurred in connection with the Sithe Energies acquisition.

Cash used in investing activities for 2003 totaled $266 million. Our capital spending totaled $333 million and was primarily comprised of routine capital maintenance of our existing asset base. Of this amount, we spent approximately $40 million on the construction of Rolling Hills, which began commercial operations in June 2003. Our proceeds from asset sales totaled approximately $72 million and primarily relate to our sale of Hackberry LNG Terminal LLC ($35 million), SouthStar ($20 million), and generation equity investments ($25 million), which were offset by $10 million in cash outflows associated with the sale of our European communications business.

During 2002, cash provided by investing activities totaled $677 million. Our capital spending totaled $947 million and was primarily comprised of improvements to the existing asset base. Of this amount, we spent approximately $195 million on the construction of Rolling Hills. Additionally, we spent $83 million on our discontinued communications business and incurred $54 million in capital expenditures associated with information technology. Business acquisitions of $20 million relate to our acquisition of Northern Natural, net of cash acquired. We received $1.5 billion in proceeds from asset sales primarily from the sales of Northern Natural in August 2002 ($879 million), the Hornsea gas storage facility in September 2002 ($189 million) and the Rough gas storage facility in November 2002 ($500 million). Other investing activities include proceeds from the sale of Northern Natural bonds.

***Financing Activities.*** Net cash used in financing activities during the 2004 totaled $115 million. Our financing cash outflows were primarily related to repayments of long-term debt totaling $650 million and consisted primarily of the following payments:

- $223 million to redeem the outstanding ChevronTexaco junior notes;
- $185 million under our ABG Gas Supply financing;
- $95 million for a maturing series of Illinova senior notes;
- $78 million on the Tilton capital lease; and
- $65 million on Illinois Power s transitional funding trust notes.

These repayments of long-term debt were offset by proceeds from our $600 million secured term loan, net of issuance costs of $19 million. We made semi-annual dividend payments totaling $22 million on our Series C preferred stock and made distributions to minority interest owners totaling $32 million.

During 2003, cash used for financing activities totaled $900 million. The following summarizes significant items:

- Repayments of $128 million, net, under our revolving credit facilities.

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Long-term debt proceeds, net of issuance costs, for 2003 totaled $2.2 billion and consisted of: (1) $311 million associated with the October 2003 follow-on offering of the DHI notes; (2) $1,607 million associated with our August 2003 refinancing transaction, (3) $142 million from the delayed issuance of $150 million in Illinois Power 11.5% Mortgage Bonds due 2010 and (4) $159 million from the Term A loan drawn in connection with the April 2003 credit facility restructuring.

In connection with the Series B Exchange, we made a $225 million cash payment to ChevronTexaco.

Repayments of long-term debt totaled $2.7 billion and consisted of: (1) $696 million prepayment of the outstanding balance under the Black Thunder financing; (2) $609 million purchase of DHI s previously outstanding 2005/2006 senior notes; (3) $360 million prepayment of the Term B loan outstanding under DHI s April 2003 restructured credit facility; (4) $200 million prepayment of the Term A loan outstanding under DHI s April 2003 restructured credit facility; (5) $200 million in payments under the Renaissance and Rolling Hills interim financing; (6) $190 million in payments of Illinois Power mortgage bond maturities; (7) $100 million payment on Illinois Power s term loan; (8) $165 million payment in full for the GEN facility capital lease; (9) $86 million in payments on Illinois Power s transitional funding trust notes; (10) $74 million in payments under the ABG Gas Supply financing; (11) $62 million in payments under the Black Thunder secured financing prior to its prepayment; (12) $5 million purchase of Illinova senior notes on the open market; and (13) $2 million in payments on the ChevronTexaco junior notes.

Distributions to minority interest owners totaling $21 million.

During 2002, cash used for financing activities totaled $44 million. The following summarizes significant items:

Net long-term debt proceeds consisted primarily of the February 2002 issuance by DHI of $500 million of 8.75% senior notes due February 2012, the December 2002 issuance by Illinois Power of $400 million of 11.5% Mortgage bonds due 2010 and proceeds from the ABG Gas Supply financing;

Repayments of long-term borrowings consisted of: (1) $88 million in transitional funding notes relating to Illinois Power; (2) $90 million relating to the April 2002 purchase of Northern Natural s senior unsecured notes due 2005; (3) $92 million in principal payments related to the Black Thunder financing; (4) $200 million relating to the July 2002 DHI 6.875% senior note repayment; (5) $96 million relating to the July 2002 Illinois Power mortgage bond repayment; and (6) $59 million in repayments under the ABG Gas Supply financing;

In July 2002, we completed a $200 million interim financing secured by interests in our Renaissance and Rolling Hills merchant power generation facilities. In June 2002, we completed a $250 million interim financing representing an advance on a portion of the proceeds from the sale of our U.K. natural gas storage facilities. In September 2002, we sold the entity that owned the Hornsea storage facility, and, in October 2002, we repaid approximately $189 million of this interim financing with the proceeds. In November 2002, we sold the entities that owned the Rough facilities and repaid the remaining balance of this financing with a portion of the proceeds;

Repayments of commercial paper borrowings and revolving credit facilities of Dynegy and DHI totaled approximately $614 million in the aggregate and borrowings totaled an aggregate of approximately $136 million under the Dynegy and DHI revolving credit facilities. During the same period, repayments of commercial paper borrowings and revolving credit facilities for Illinois Power totaled approximately $238 million;

Proceeds from the sale of capital stock totaled $205 million related to ChevronTexaco s January 2002 purchase of approximately 10.4 million shares of Class B common stock pursuant to its preemptive rights under our shareholder agreement. Capital stock proceeds also included $24 million of cash inflows associated with cash received from senior management associated with a December 2001 private placement of shares of our Class A common stock;

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In March 2002, Illinova consummated a tender offer pursuant to which it paid $28 million in cash for approximately 73% of the then-outstanding shares of Illinois Power s preferred stock; and

We made dividend payments of $40 million to the holders of Class A common stock and $15 million to the holder of Class B common stock.

**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, natural gas, and natural gas liquids. 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 gas-fired electricity generation. Our liquids businesses are also subject to seasonal factors impacting both volumes and prices.

**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 six critical accounting policies that require a significant amount of estimation and judgment and are considered to be important to the portrayal of our financial position and results of operations:

Revenue Recognition;

Valuation of Tangible and Intangible Assets;

Estimated Useful Lives;

Accounting for Contingencies, Guarantees and Indemnifications;

Accounting for Income Taxes; and

Valuation of Pension Assets and Liabilities.

**Revenue Recognition**

We utilize two comprehensive accounting models in reporting our consolidated financial position and results of operations as required by GAAP an accrual model and a fair value model. We determine the appropriate model for our operations based on guidance provided in applicable accounting standards and positions adopted by the FASB or the SEC. We have applied these accounting policies on a consistent basis during the three years in the period ended December 31, 2004, except as required by the adoption of EITF Issue 02-03, which rescinded EITF Issue 98-10.

The accrual model has historically been used to account for substantially all of the operations conducted in our GEN, NGL and REG segments. These segments consist largely of the ownership and operation of physical assets that we use in various generation, processing and delivery operations. The business of these segments includes the generation of electricity, the separation of natural gas liquids into their component parts from a stream of natural gas and the transportation or transmission of commodities through pipelines or over

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transmission lines. End sales from these businesses result in physical delivery of commodities to our wholesale, commercial, industrial and retail customers. We recognize revenue from these transactions when the product or service is delivered to a customer.

The fair value model has historically been used to account for certain forward physical and financial transactions, occurring primarily in the CRM and GEN segments, which meet criteria defined by the FASB or the EITF. The criteria are complex, but generally require these contracts to relate to future periods, to contain fixed price and volume components and to have terms that require or permit net settlement of the contract in cash or the equivalent. The FASB determined that the fair value model is the most appropriate method for accounting for these types of contracts. In part, this conclusion is based on the cash settlement provisions in these agreements, as well as the volatility in commodity prices, interest rates and, if applicable, foreign exchange rates, which impact the valuation of these contracts. Since these transactions may be settled in cash or the equivalent, the value of the assets and liabilities associated with these transactions is reported at estimated settlement value based on current prices and rates as of each balance sheet date.

We estimate the fair value of our marketing portfolio using a liquidation value approach assuming that the ability to transact business in the market remains at historical levels. The estimated fair value of the portfolio is computed by multiplying all existing positions in the portfolio by estimated prices, reduced by a time value of money adjustment and deduction of reserves for credit and price. The estimated prices in this valuation are based either on (1) prices obtained from market quotes, when there are an adequate number of quotes to consider the period liquid, or, if market quotes are unavailable, or the market is not considered to be liquid, (2) prices from a proprietary model which incorporates forward energy prices derived from market quotes and values from previously executed transactions. The amounts recorded as revenue change as these estimates are revised to reflect actual results and changes in market conditions or other factors, many of which are beyond our control.

Typically, derivative contracts can be accounted for in three different ways: (1) as an accrual contract, if the criteria for the normal purchase normal sale exemption are met and documented; (2) as a cash flow or fair value hedge, if the criteria are met and documented; or (3) as a mark-to-market contract with changes in fair value recognized in current period earnings. Generally, we only mark-to-market through earnings our derivative contracts if they do not qualify for the normal purchase normal sale exemption or as a cash flow hedge. Because derivative contracts can be accounted for in three different ways, and as the normal purchase normal sale exemption and cash flow hedge accounting are elective, the accounting treatment used by another party for a similar transaction could be different than the accounting treatment we use.

**Valuation of Tangible and Intangible Assets**

We evaluate long-lived assets, such as property, plant and equipment, investments and goodwill, when events or changes in circumstances lead to a reduction in the estimated useful lives or estimated future cash flows sufficient to indicate that the carrying value of such assets may not be recoverable. Factors we consider important, which could trigger an impairment analysis, include, among others:

- significant underperformance relative to historical or projected future operating results;
- significant changes in the manner of our use of the assets or the strategy for our overall business;
- significant negative industry or economic trends; and

significant declines in stock value for a sustained period.

We assess the carrying value of our property, plant and equipment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the related discounted cash flows of the assets and recording a loss if the resulting estimated fair value is less than the book value. For assets identified as held for sale, the book value is compared to the estimated fair value, which may also include estimates based upon comparables or quoted market prices, to determine if an impairment loss is required. Please see Note 4 Restructuring and Impairment Charges beginning on page F-30 for discussion of impairment charges we recognized for 2004, 2003 and 2002.

We follow the guidance of APB 18, The Equity Method of Accounting for Investments in Common Stock, SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities, and EITF No. 02-14, Whether an Investor Should Apply the Equity Method of Accounting to Investments Other Than Common Stock, when reviewing our investments. The book value of the investment is compared to the estimated fair value, based either on discounted cash flow projections or quoted market prices, if available, to determine if an impairment is required. We record a loss when the decline in value is considered other than temporary.

We follow the guidance set forth in SFAS No. 142, Goodwill and Other Intangible Assets, when assessing the carrying value of our goodwill. Accordingly, we evaluate our goodwill for impairment on an annual basis or when certain events warrant an assessment. Our evaluation is based, in part, on our estimate of future cash flows. Please see Note 10 Goodwill beginning on page F-41 for discussion of impairment charges we recognized for 2003 and 2002.

Our assessments regarding valuation of tangible and intangible assets are subject to estimates and judgment of management. Market conditions, energy prices, estimated useful lives of the assets, discount rate assumptions and legal factors impacting our business may have a significant effect on the estimates and judgment of management. If different judgments were applied, estimates could differ significantly. Actual results could vary materially from these estimates.

**Estimated Useful Lives**

The estimated useful lives of our long-lived assets are used to compute depreciation expense, future asset retirement obligations and are also used in impairment testing. Estimated useful lives are based, among other things, on the assumption that we provide an appropriate level of capital expenditures while the assets are still in operation. Without these continued capital expenditures, the useful lives of these assets could decrease significantly. Estimated lives could be impacted by such factors as future energy prices, environmental regulations, various legal factors and competition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future asset retirement obligations may be insufficient and impairments in carrying values of tangible and intangible assets may result.

**Accounting for Contingencies, Guarantees and Indemnifications**

We are involved in numerous lawsuits, claims, proceedings, joint venture audits and tax-related audits in the normal course of our operations. In accordance with SFAS No. 5, Accounting for Contingencies, 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 the balance sheet. 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. Our estimates and judgment could change based on new information, changes in laws or regulations, changes in management s plans or intentions, the outcome of legal proceedings, settlements or other factors. If different estimates and judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts. Actual results could vary materially from theses reserves.

Liabilities are recorded when 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

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liability. These assumptions involve the judgments and estimates of management and any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

We follow the guidance of FIN No. 45 Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others for disclosure and accounting of various guarantees and indemnifications entered into during the course of business. When a guarantee or indemnification subject of FIN No. 45 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. Actual results may materially differ from the estimated fair value of such guarantees and indemnifications.

Under the provisions of SFAS No. 143, Asset Retirement Obligations, we are required to record legal obligations to retire tangible, long-lived assets on our balance sheet as liabilities, which are recorded at a discount, when the liability is incurred. Significant judgment is involved in estimating our future cash flows associated with such obligations, as well as the ultimate timing of the cash flows. If our estimates on the amount or timing of the cash flow change, the change may have a material impact on our results of operations.

**Accounting for Income Taxes**

We follow the guidance in SFAS No. 109, Accounting for Income Taxes, which requires that we use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary 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 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.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and, to the extent we believe that it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

Management believes future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize assets for which no reserve has been established. While we have considered these factors in assessing the need for a valuation allowance, there is no assurance that a valuation allowance would not need to be established in the future if information about future years change. Any change in the valuation allowance would impact our income tax provision and net income in the period in which such a determination is made.

Please see Note 13 Income Taxes beginning on page F-49 for further discussion of our accounting for income taxes and any change in our valuation allowance.

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**Valuation of Pension Assets and Liabilities**

Our pension and post-retirement benefit costs are developed from actuarial valuations. Inherent in these valuations are key assumptions provided by us to our actuaries, including the discount rate and expected long-term rate of return on plan assets. Material changes in our pension and post-retirement benefit costs may occur in the future due to changes in these assumptions, changes in the number of plan participants and changes in the level of benefits provided.

The discount rate is subject to change each year, consistent with changes in applicable high-quality, long-term corporate bond indices. Long-term interest rates declined during 2004. Accordingly, at December 31, 2004, we used a discount rate of 5.75%, a decline of 25 basis points from the 6.0% rate used as of December 31, 2003. This decline in the discount rate had an immaterial impact on the underfunded status of our pension plans.

The expected long-term rate of return on pension plan assets is selected by taking into account the expected duration of the projected benefit obligation for the plans, the asset mix of the plans and the fact that the plan assets are actively managed to mitigate downside risk. Based on these factors, our expected long-term rate of return as of January 1, 2005 is 8.25%, compared with 8.75% during 2004. This change did not impact 2004 pension expense, but it will adversely impact pension expense beginning in 2005. Although we expect 2005 pension expense to be lower than 2004 pension expense by approximately $13 million, primarily due to the sale of Illinois Power, the decrease will be partially offset by the decrease in the expected long-term rate of return, coupled with the decreased discount rate discussed above and the passage of time.

On December 31, 2004, our annual measurement date, the accumulated benefit obligation related to our pension plans exceeded the fair value of the pension plan assets (such excess is referred to as an unfunded accumulated benefit obligation). This difference is attributed to (1) an increase in the accumulated benefit obligation that resulted from the decrease in the discount rate and the expected long-term rate of return and (2) a decline in the fair value of the plan assets due to a sharp decrease in the equity markets through December 31, 2002, which was partially recovered during 2003 and 2004. As a result, in accordance with SFAS No. 87, Employers Accounting for Pensions, as of December 31, 2004, we have recognized a charge to accumulated other comprehensive loss of $13 million (net of taxes of $7 million), which decreases stockholders equity. The charge to stockholders equity for the excess of additional pension liability over the unrecognized prior service cost represents a net loss not yet recognized as pension expense.

A relatively small difference between actual results and assumptions used by management may have a material effect on our financial statements. Assumptions used by another party could be different than our assumptions. The following table summarizes the sensitivity of pension expense and our projected benefit obligation, or PBO, to changes in the discount rate and the expected long-term rate of return on pension assets:

| | Impact on PBO, December 31, 2005 | Impact on 2005 Expense |
|---|---|---|
| | (in millions) | |
| Increase in Discount Rate 50 basis points | $ (13.9) | $ (1.2) |
| Decrease in Discount Rate 50 basis points | 15.5 | 1.3 |

| | |
|---|---|
| Increase in Expected Long-term Rate of Return  50 basis points | (0.5) |
| Decrease in Expected Long-term Rate of Return  50 basis points | 0.5 |

We expect to make $28 million in cash contribution related to our pension plans during 2005. In addition, it is likely that we will be required to continue to make contributions to the pension plan beyond 2005. Although it is difficult to estimate these potential future cash requirements due to uncertain market conditions, we currently expect that the cash requirements would be approximately $19 million in 2006 and $26 million in 2007.

Please see Note 19  Employee Compensation, Savings and Pension Plans beginning on page F-73 for further discussion of our pension related assets and liabilities.

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**RECENT ACCOUNTING PRONOUNCEMENTS**

See Note 2 Accounting Policies Accounting Principles Adopted beginning on page F-21 for a discussion of recently issued accounting pronouncements affecting us. Specifically, we adopted EITF 04-8, EITF 02-14 and certain provisions of FIN No. 46R on January 1, 2004, and we adopted other portions of FIN No. 46R effective December 31, 2003. We adopted SFAS No. 150 and EITF Issue 03-11 effective July 1, 2003. We adopted FIN No. 45 and SFAS No. 143 effective January 1, 2003. We adopted the net presentation provisions of EITF Issue 02-03 in the third quarter 2002 and we adopted the provision within EITF Issue 02-03 that rescinds EITF Issue 98-10 effective January 1, 2003.

**RISK-MANAGEMENT DISCLOSURES**

The following table provides a reconciliation of the risk-management data on the consolidated balance sheets, statements of operations and statements of cash flows:

| | As of and for the Year Ended December 31, 2004 (in millions) |
|---|---|
| **Balance Sheet Risk-Management Accounts** | |
| Fair value of portfolio at January 1, 2004 | $ (137) |
| Risk-management gains recognized through the income statement in the period, net | 6 |
| Cash paid related to risk-management contracts settled in the period, net | 85 |
| Changes in fair value as a result of a change in valuation technique (1) | |
| Non-cash adjustments and other (2) | (87) |
| Fair value of portfolio at December 31, 2004 | $ (133) |
| **Income Statement Reconciliation** | |
| Risk-management gains recognized through the income statement in the period, net | $ 6 |
| Physical business recognized through the income statement in the period, net (3) | (129) |
| Non-cash adjustments and other | 13 |
| **Net recognized operating loss** | $ (110) |
| **Cash Flow Statement** | |
| Cash paid related to risk-management contracts settled in the period, net | $ (85) |
| Estimated cash paid related to physical business settled in the period, net (3) | (129) |
| Timing and other, net (4) | 54 |
| **Cash paid during the period** | $ (160) |
| **Risk-Management cash flow adjustment for the year ended December 31, 2004 (5)** | $ (50) |

(1) Our modeling methodology has been consistently applied.
(2) This amount primarily consists of changes in value associated with cash flow hedges on forward power sales.
(3) This amount includes capacity payments on our power tolling arrangements and the $115 million charge associated with our entry into a back-to-back power purchase agreement offset by the $88 million gain recognized by our exit from four gas transportation contracts.
(4) This amount consists primarily of cash received in connection with the settlement of cash flow hedges.
(5) This amount is calculated as Cash paid during the period less Net recognized operating loss.

The net risk management liability of $133 million is the aggregate of the following line items on the 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.

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**Risk-Management Asset and Liability Disclosures**

The following table depicts the mark-to-market value and cash flow components, based on contract terms, of our net risk-management assets and liabilities at December 31, 2004. As opportunities arise to monetize positions that we believe will result in an economic benefit to us, we may receive or pay cash in periods other than those depicted below.

**Net Risk-Management Asset and Liability Disclosures**

| | Total | 2005 | 2006 | 2007 | 2008 | 2009 | Thereafter |
|---|---|---|---|---|---|---|---|
| | | | | (in millions) | | | |
| Mark-to-Market (1) | $ (96) | $ (7) | $ (8) | $ (48) | $ (21) | $ (10) | $ (2) |
| Cash Flow (2) | (99) | (5) | (7) | (51) | (23) | (12) | (1) |

(1) Mark-to-market reflects the fair value of our risk-management asset position, which considers time value, credit, price and other reserves necessary to determine fair value. These amounts exclude the fair value associated with certain derivative instruments designated as hedges. The net risk-management liabilities at December 31, 2004 of $133 million on the consolidated balance sheets includes the $96 million herein as well as hedging instruments. Cash flows have been segregated between periods based on the delivery date required in the individual contracts.

(2) Cash Flow reflects undiscounted cash inflows and outflows by contract based on the tenor of individual contract position for the remaining periods. These anticipated undiscounted cash flows have not been adjusted for counterparty credit or other reserves. These amounts exclude the cash flows associated with certain derivative instruments designated as hedges.

The following table provides an assessment of net contract values by year as of December 31, 2004, based on our valuation methodology.

**Net Fair Value of Risk-Management Portfolio**

| | Total | 2005 | 2006 | 2007 | 2008 | 2009 | Thereafter |
|---|---|---|---|---|---|---|---|
| | | | | (in millions) | | | |
| Market Quotations (1) | $ (62) | $ (7) | $ (8) | $ (35) | $ (11) | $ (3) | $ 2 |
| Prices Based on Models (2) | (34) | | | (13) | (10) | (7) | (4) |
| Total | $ (96) | $ (7) | $ (8) | $ (48) | $ (21) | $ (10) | $ (2) |

(1) Prices obtained from actively traded, liquid markets for commodities other than natural gas positions. All natural gas positions for all periods are contained in this line based on available market quotations.

(2) See discussion of our use of long-term models in Critical Accounting Policies beginning on page 74.

**Derivative Contracts**

The absolute notional contract amounts associated with our commodity risk-management, interest rate and foreign currency exchange contracts are discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 83.

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**UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION**

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

- projected operating or financial results, including anticipated cash flows from operations;
- expectations regarding capital expenditures, interest expense and other payments;
- our ability to continue execution of the cost-savings measures we have identified;
- our beliefs and assumptions relating to our liquidity position, including our ability to satisfy or refinance our significant debt maturities and other obligations before or as they come due;
- our ability to access the capital markets as and when needed;
- our ability to address our substantial leverage;
- our ability to compete effectively for market share with industry participants;
- beliefs about the outcome of legal and administrative proceedings, including matters involving the western power and natural gas markets, shareholder claims and environmental and master netting agreement matters, as well as the investigations primarily relating to Project Alpha and our past trading practices;
- our ability to integrate the entities recently acquired in the Sithe Energies acquisition and their operations and to achieve our financial and operational goals associated with that acquisition; and
- our ability to complete our exit from the CRM business and the costs associated with this exit.

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 including, among others:

the timing and extent of changes in weather and commodity prices, including the relationships between prices for power and natural gas or other power generating fuels, commonly referred to as the spark spread, and the frac spread;

the effects of competition in our asset-based business lines;

the effects of the Sithe Energies acquisition and the consolidation of the related project debt;

our ability to fund the environmental and emission control projects mandated by the Baldwin consent decree following its approval by the Illinois federal district court;

the condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions, and our ability to engage in capital-raising transactions;

our financial condition, including our ability to satisfy our significant debt maturities and debt service obligations;

our ability to realize our significant deferred tax assets, including loss carryforwards;

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- the effectiveness of our risk-management policies and procedures and the ability of our counterparties to satisfy their financial commitments;

- the liquidity and competitiveness of wholesale trading markets for energy commodities, particularly natural gas, electricity and natural gas liquids;

- operational factors affecting the start up or ongoing commercial operations of our power generation, natural gas and natural gas liquids facilities, including catastrophic weather-related damage, regulatory approvals, permit issues, unscheduled blackouts, outages or repairs, unanticipated changes in fuel costs or availability of fuel emission credits, the unavailability of gas transportation and the unavailability of electric transmission service or workforce issues;

- increased interest expense and restrictive covenants resulting from our non-investment grade credit rating;

- counterparties collateral demands and other factors affecting our liquidity position and financial condition;

- our ability to operate our businesses efficiently, manage capital expenditures and costs (including general and administrative expenses) tightly and generate earnings and cash flow from our asset-based businesses in relation to our substantial debt and other obligations;

- the direct or indirect effects on our business of any further downgrades in our credit ratings (or actions we may take in response to changing credit ratings criteria), including refusal by counterparties to enter into transactions with us and our inability to obtain credit or capital in amounts or on terms that are considered favorable;

- the costs and other effects of legal and administrative proceedings, settlements, investigations and claims, including legal proceedings related to the western power and natural gas markets, shareholder claims, claims arising out of our CRM business and environmental liabilities that may not be covered by indemnity or insurance, as well as the U.S. Attorney and other similar investigations primarily surrounding Project Alpha and our past trading practices;

- the effects of our efforts to improve our internal control structure, particularly with respect to the remediation of the deficiencies discussed under Item 9A Controls and Procedures;

- other North American regulatory or legislative developments that affect the demand and pricing for energy generally, that increase the environmental compliance cost for our facilities or that impose liabilities on the owners of such facilities; and

- general political conditions and developments in the United States and in foreign countries whose affairs affect our asset-based businesses including any extended period of war or conflict.

In addition, there may be other factors that could cause our actual results to be materially different from the results referenced in the forward-looking statements, some of which are included elsewhere in this Form 10-K. Many of these factors will be important in determining our actual future results. Consequently, no forward-looking statement can be guaranteed. Our actual future results may vary materially from those expressed or implied in any forward-looking statements.

All forward-looking statements contained in this Form 10-K are qualified in their entirety by this cautionary statement. Forward-looking statements speak only as of the date they are made, and we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this Form 10-K, except as otherwise required by applicable law.

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**Item 7A.** ***Quantitative and Qualitative Disclosures About Market Risk***

We are exposed to commodity price variability related to our power generation and natural gas liquids businesses. In addition, fuel requirements at our power generation, gas processing and fractionation facilities represent additional commodity price risks to us. 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 and swaps and options traded in the over-the-counter 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 and natural gas processing plants.

The potential for changes in the market value of our commodity, interest rate and currency 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, natural gas liquids and other similar products;
- 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; and
- Currency rate risks result from exposures to changes in spot prices, forward prices and volatilities in currency 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.*** In addition to applying business judgment, senior management uses a number of quantitative tools to monitor our exposure to market risk. These tools include stress and scenario analyses performed periodically that measure the potential effects of various market events.

The modeling of the risk characteristics of our mark-to-market portfolio involves a number of assumptions and approximations. We estimate VaR using a JP Morgan RiskMetrics approach assuming a one-day holding period. Inputs for the VaR calculation are prices, positions, instrument valuations and the variance-covariance matrix. 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 better reflect current asset and liability volatilities, 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 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% confidence level were used. This means that there is a one in 20 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. Thus, a 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.

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In addition, we have provided our VaR using a one-day time horizon and a 99% 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 GEN and CRM segments.

**Daily and Average VaR for Risk-Management Portfolio**

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| | (in millions) | |
| One Day VaR 95% Confidence Level | $ 5 | $ 4 |
| One Day VaR 99% Confidence Level | $ 7 | $ 6 |
| Average VaR for the Year-to-Date Period 95% Confidence Level | $ 4 | $ 6 |

***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 further reduce credit risk 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 to counterparties on a daily basis.

The following table represents our credit exposure at December 31, 2004 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

**Credit Exposure Summary**

| | Investment Grade Quality | Non-Investment Grade Quality | Total |
|---|---|---|---|
| | | (in millions) | |
| **Type of Business:** | | | |
| Financial Institutions | $ 146 | $ | $ 146 |

| | | | |
|---|---|---|---|
| Commercial/Industrial/End Users | 63 | 25 | 88 |
| Utility and Power Generators | 21 | | 21 |
| Oil and Gas Producers | 4 | | 4 |
| Total | $ 234 | $ 25 | $ 259 |

Of the $25 million in credit exposure to non-investment grade counterparties, approximately 96% ($24 million) is collateralized or subject to other credit exposure protection.

***Interest Rate Risk.*** Interest rate risk primarily results from variable rate debt obligations. Although changing interest rates impact the discounted value of future cash flows, and therefore the value of our risk management portfolios, the relative near-term nature and size of our risk management portfolios minimizes the impact. Management continues to monitor our exposure to fluctuations in interest rates and may execute swaps or other financial instruments to change our risk profile for this exposure.

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As of December 31, 2004, our fixed rate debt instruments as a percentage of total debt instruments was equal to 72%. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of December 31, 2004, it is estimated that a one percentage point interest rate movement in the average market interest rates (either higher or lower) over the 12 months ended December 31, 2005 would either decrease or increase income before taxes by approximately $15 million. Hedging instruments that impact such interest rate exposure are included in the sensitivity analysis. Over time, we may seek to reduce the percentage of fixed rate financial obligations in our debt portfolio through the use of swaps or other financial instruments.

***Foreign Currency Exchange Rate Risk.*** Foreign currency risk arises from our investments in affiliates and subsidiaries owned and operated in foreign countries. Such risk is also a result of risk management transactions with customers in countries outside the United States. Management continually monitors our exposure to fluctuations in foreign currency exchange rates. When possible, contracts are denominated in or indexed to the U.S. dollar.

At December 31, 2004, our primary foreign currency exchange rate exposures were the Canadian Dollar and European Euro. Additionally, as further discussed in Liquidity and Capital Resources Internal Liquidity Sources Current Liquidity beginning on page 48, at December 31, 2004, approximately $47 million cash denominated in the U.K. Pound, the Euro and the Canadian Dollar remains in the U.K. and Canada.

***Derivative Contracts.*** The absolute notional financial contract amounts associated with our commodity risk-management and interest rate contracts were as follows at December 31, 2004 and December 31, 2003, respectively:

**Absolute Notional Contract Amounts**

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| Natural Gas (Trillion Cubic Feet) | 1.084 | 2.364 |
| Electricity (Million Megawatt Hours) | 11.652 | 8.713 |
| Fair Value Hedge Interest Rate Swaps (In Millions of U.S. Dollars) | $ 525 | $ 25 |
| Fixed Interest Rate Received on Swaps (%) | 4.331 | 5.706 |
| Cash Flow Hedge Interest Rate Swaps (In Millions of U.S. Dollars) | $ | $ 405 |
| Fixed Interest Rate Paid on Swaps (%) | | 3.448 |
| Interest Rate Risk-Management Contract (In Millions of U.S. Dollars) | $ 25 | $ 306 |
| Fixed Interest Rate Paid (%) | 5.998 | 5.570 |

**Item 8.** ***Financial Statements and Supplementary Data***

Our financial statements and financial statement schedules are set forth at pages F-1 through F-110 inclusive, found at the end of this annual report, and are incorporated herein by reference.

**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 our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in our SEC reports is recorded,

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processed, summarized and reported within the time periods specified by the SEC. This evaluation also considered the work completed relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002, which is further described below.

Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2004, as a result of the material weakness discussed below, our disclosure controls and procedures were not effective to ensure that the information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the requisite time periods. Due to the material weakness discussed below, in preparing our financial statements at and for the year ended December 31, 2004, we performed additional procedures relating to the tax provision designed to ensure that such financial statements were fairly presented in all material respects in accordance with generally accepted accounting principles.

***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 generally accepted accounting principles.

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 CEO and CFO, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2004. In making this assessment, we used the criteria set forth by COSO in *Internal Control Integrated Framework*.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements would not be prevented or detected. As of December 31, 2004, we did not maintain effective control over the calculation of the tax provision and deferred income tax balances in accordance with generally accepted accounting principles. Specifically, our processes, procedures and controls related to the preparation and review of the quarterly and annual tax provisions were not adequate to ensure that the deferred tax provision and classification of deferred tax balances were prepared in accordance with generally accepted accounting principles. This control deficiency resulted in year-end audit adjustments to correct the income tax benefit recognized in 2004 and the related deferred income tax asset account. Also, adjustments were identified relating to prior periods affecting a deferred tax liability that was erroneously included in the fourth quarter 2003 impairment calculation of Illinois Power, resulting in the impairment and the deferred tax liability being misstated. Additionally, errors were discovered in our previously completed tax basis balance sheet review which misstated the deferred tax liability account at December 31, 2003 and the corresponding tax benefit for 2003, 2002 and periods prior to 2002. As a result, we restated our 2003 and 2002 annual financial statements and 2004 and 2003 interim financial statements in this 2004 Annual Report on Form 10-K. Further, this control deficiency could have resulted in a misstatement of the tax provision and deferred tax balances resulting in a material misstatement to the annual or interim consolidated financial statements that may not have been prevented or detected. Therefore, we have concluded that this control deficiency constitutes a material weakness.

Based on our assessment, management has concluded that, as of December 31, 2004, we did not maintain effective internal control over our financial reporting due to the material weakness in our tax accounting and tax reconciliation processes, procedures and controls, as further described above.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public

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accounting firm, as stated in their report (which expressed an unqualified opinion on management s assessment and an adverse opinion on the effectiveness of our internal control over financial reporting as of December 31, 2004), which appears on page F-00.

***Changes in Internal Controls.*** Other than as noted below, there were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of our internal controls performed during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Prior to the fourth quarter 2004, we identified deficiencies in our tax accounting and tax reconciliation processes, procedures and controls. Although we had processes, procedures and controls in place relating to the preparation and review of the quarterly and annual tax provisions, we subsequently determined that such processes, procedures and controls were not adequate to ensure that the deferred tax provision and classification of deferred tax balances were prepared in accordance with generally accepted accounting principles. As a result, we restated our 2003 and 2002 annual financial statements and 2004 and 2003 interim financial statements in this 2004 Annual Report on Form 10-K. We have taken the following steps to improve our internal controls around our tax accounting and tax reconciliation processes, procedures and controls:

- Increased the levels of review in the preparation of the quarterly and annual tax provision;

- Formalized processes, procedures and documentation standards relating to income tax provisions; and

- Restructured our Tax Department to ensure appropriate segregation of duties regarding preparation and review of the quarterly and annual tax provision.

We believe we have taken steps necessary to remediate this material weakness relating to taxes, although certain of the corrective processes, procedures and controls were not in place as of December 31, 2004. Additionally, other processes, procedures and controls were not in place for an adequate period of time to conclude that they were operating effectively as of December 31, 2004. Accordingly, we will continue to monitor the effectiveness of these processes, procedures and controls and will make any changes management determines appropriate

In addition, during the course of completing the work relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002, we identified deficiencies in our internal control over financial reporting, including matters relating to system access and system implementation controls, segregation of duties and documentation of controls and procedures and their effective operation and monitoring. While we do not consider these deficiencies material weaknesses, we believe they should be remediated. Among other things, we have taken, and are taking, the following actions:

- Improved controls related to logging and system access; and

- Improved controls related to balance sheet classifications.

**Item 9B.** ***Other Information***

***Baldwin Consent Decree.*** Since November 1999, DMG has been the subject of an NOV from the EPA and a complaint filed by the EPA and the DOJ in federal district court alleging violations of the Clean Air Act and related federal and Illinois regulations related to certain maintenance, repair and replacement activities at our Baldwin generating station. We have reached agreement with the EPA, the DOJ, the State of Illinois and the environmental group intervenors on terms to settle the litigation. A consent decree was signed by all parties and lodged with the U.S. District Court for the Southern District of Illinois on March 7, 2005, and is subject to final approval of the Court following public comment. The consent decree requires us to (i) pay a $9 million civil penalty; (ii) fund several environmental projects in the additional aggregate amount of $15 million; and (iii) invest $321 million through 2010, and $224 million from 2011 through 2012, respectively, in emission control projects at our Baldwin, Vermilion and Havana plants. Please read Note 16 Commitments and Contingencies Summary of Material Legal Proceedings Baldwin Station Litigation beginning on page F-57 for further discussion of this lawsuit and consent decree.

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## PART III

**Item 10.** ***Directors and Executive Officers of the Registrant***

***Executive Officers***. The information required by this Item 10 with respect to our executive officers is set forth in Part I of this annual report under the caption Item 1A. Executive Officers beginning on page 30**,** which information is incorporated herein by this reference.

***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 incorporated as an exhibit to this Form 10-K.

***Other Information***. The other information required by this Item 10 will be contained in our definitive proxy statement for our 2005 annual meeting of shareholders under the headings Proposal 1 Election of Directors and Executive Compensation Section 16(a) Beneficial Ownership Reporting Compliance and is incorporated herein by reference. The proxy statement will be filed with the SEC not later than 120 days after December 31, 2004.

**Item 11.** ***Executive Compensation***

Information with respect to executive compensation will be contained in the upcoming proxy statement under the heading Executive Compensation and is incorporated herein by reference.

**Item 12.** ***Security Ownership of Certain Beneficial Owners and Management***

Information regarding ownership of our outstanding securities will be contained in the upcoming proxy statement under the heading Principal Shareholders and is incorporated herein by reference.

**Item 13.** ***Certain Relationships and Related Transactions***

Information regarding related party transactions will be contained in the upcoming proxy statement under the headings Principal Stockholders, Proposal 1 Election of Directors and Executive Compensation Employment Agreements and Change-in-Control Agreements and Certain Relationships and Related Transactions and is incorporated herein by reference.

**Item 14.** ***Principal Accountant Fees and Services***

Information regarding principal accountant fees and services will be contained in the upcoming proxy statement under the heading Independent Auditors and is incorporated herein by reference.

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## PART IV

**Item 15.** ***Exhibits, 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 annual report:

1. Financial Statements Our consolidated financial statements are incorporated under Item 8. of this annual report.

2. Financial Statement Schedules Financial Statement Schedules are incorporated under Item 8. of this annual report.

3. Exhibits The following instruments and documents are included as exhibits to this annual report. All management contracts or compensation plans or arrangements set forth in such list are marked with a .

| Exhibit Number | Description |
|---|---|
| 2.1 | Purchase Agreement dated February 2, 2004 among Dynegy Inc., Illinova Corporation, Illinova Generating Company and Ameren Corporation (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Dynegy Inc. filed on February 4, 2004, File No. 1-15659). |
| 3.1 | Amended and Restated Articles of Incorporation of Dynegy Inc. (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 25, 2001). |
| 3.2 | Statement of Resolution Establishing Series of Series C Convertible Preferred Stock of Dynegy Inc. (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 3.3 | Amended and Restated Bylaws of Dynegy Inc. (incorporated by reference to Exhibit 3.3 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |
| 4.1 | Indenture, dated as of December 11, 1995, by and among NGC Corporation, the Subsidiary Guarantors named therein and the First National Bank of Chicago, as Trustee (incorporated by reference to exhibits to the Registration Statement on Form S-3 of NGC Corporation, Registration No. 33-97368). |
| 4.2 | First Supplemental Indenture, dated as of August 31, 1996, by and among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156). |
| 4.3 | Second Supplemental Indenture, dated as of October 11, 1996, by and among NGC Corporation, the Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156). |
| 4.4 | |

Subordinated Debenture Indenture between NGC Corporation and The First National Bank of Chicago, as Debenture Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156).

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| Exhibit Number | Description |
|---|---|
| 4.5 | Amended and Restated Declaration of Trust among NGC Corporation, Wilmington Trust Company, as Property Trustee and Delaware Trustee, and the Administrative Trustees named therein, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156). |
| 4.6 | Series A Capital Securities Guarantee Agreement executed by NGC Corporation and The First National Bank of Chicago, as Guarantee Trustee, dated as of May 28, 1997 (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156). |
| 4.7 | Common Securities Guarantee Agreement of NGC Corporation dated as of May 28, 1997 (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156). |
| 4.8 | Registration Rights Agreement, dated as of May 28, 1997, among NGC Corporation, NGC Corporation Capital Trust I, Lehman Brothers, Salomon Brothers Inc. and Smith Barney Inc. (incorporated by reference to Exhibit 4.11 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 1997 of NGC Corporation, File No. 1-11156). |
| 4.9 | Fourth Supplemental Indenture among NGC Corporation, Destec Energy, Inc. and The First National Bank of Chicago, as Trustee, dated as of June 30, 1997, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.12 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1997 of NGC Corporation, File No. 1-11156). |
| 4.10 | Fifth Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of September 30, 1997, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.18 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156). |
| 4.11 | Sixth Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of January 5, 1998, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.19 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156). |
| 4.12 | Seventh Supplemental Indenture among NGC Corporation, The Subsidiary Guarantors named therein and The First National Bank of Chicago, as Trustee, dated as of February 20, 1998, supplementing and amending the Indenture dated as of December 11, 1995 (incorporated by reference to Exhibit 4.20 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1997 of NGC Corporation, File No. 1-11156). |
| 4.13 | Indenture, dated as of September 26, 1996, restated as of March 23, 1998, and amended and restated as of March 14, 2001, between Dynegy Holdings Inc. and Bank One Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2000 of Dynegy Holdings Inc., File No. 0-29311). |
| 4.14 | Exchange and Registration Rights Agreement (Preferred Stock) dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |

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| Exhibit Number | Description |
|---|---|
| 4.15 | Amended and Restated Registration Rights Agreement (Common Stock) dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 4.16 | Amended and Restated Shareholder Agreement dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 4.17 | Indenture dated as of August 11, 2003 among Dynegy Holdings Inc., the guarantors named therein, Wilmington Trust Company, as trustee, and Wells Fargo Bank Minnesota, N.A., as collateral trustee, including the form of promissory note for each series of notes issuable pursuant to the Indenture (incorporated by reference to Exhibit 4.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 4.18 | Indenture dated August 11, 2003 between Dynegy Inc., Dynegy Holdings Inc. and Wilmington Trust Company, as trustee, including the form of debenture issuable pursuant to the Indenture (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 4.19 | Registration Rights Agreement dated August 11, 2003 among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 4.20 | First Supplemental Indenture dated July 25, 2003 to that certain Indenture, dated as of September 26, 1996, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659). |
| 4.21 | Eighth Supplemental Indenture dated July 25, 2003 that certain Indenture, dated as of December 11, 1995, between Dynegy Holdings Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. filed on July 28, 2003, File No. 1-15659). |
| **4.22 | Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee. |
| **4.23 | First Supplemental Indenture dated as of January 1, 1993 to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and IBJ Schroder Bank & Trust Company, as Trustee. |
| **4.24 | Second Supplemental Indenture dated as of October 23, 2001 to the Trust Indenture dated as of January 1, 1993, among Sithe/Independence Funding Corporation, Sithe/Independence Power Partners, L.P. and The Bank of New York, as Trustee. |
| | There have not been filed or incorporated as exhibits to this annual report, other debt instruments defining the rights of holders of our long-term debt, none of which relates to authorized indebtedness that exceeds 10% of our consolidated assets. We hereby agree to furnish a copy of any such instrument not previously filed to the SEC upon request. |
| 10.1 | Dynegy Inc. Amended and Restated 1991 Stock Option Plan (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156). |

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| 10.2 | Dynegy Inc. 1998 U.K. Stock Option Plan (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156). |
| 10.3 | Dynegy Inc. Amended and Restated Employee Equity Option Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156). |
| 10.4 | Dynegy Inc. 1999 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156). |
| 10.5 | Dynegy Inc. 2000 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156). |
| 10.6 | Dynegy Inc. 2001 Non-Executive Stock Incentive Plan (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080). |
| 10.7 | Dynegy Inc. 2002 Long Term Incentive Plan (incorporated by reference to Appendix A to the Definitive Proxy Statement on Schedule 14A of Dynegy Inc., File No. 1-15659, filed with the SEC on April 9, 2002). |
| 10.8 | Extant, Inc. Equity Compensation Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-47422). |
| 10.9 | Employment Agreement, effective October 23, 2002, between Bruce A. Williamson and Dynegy Inc. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2002 of Dynegy Inc., File No. 1-15659). |
| 10.10 | Employment Agreement, effective March 11, 2003, between Carol F. Graebner and Dynegy Inc. (incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.11 | Contract for Consulting Services dated March 19, 2004 between Dynegy Inc. and Daniel L. Dienstbier (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2004 of Dynegy Inc., File No. 1-15659). |
| 10.12 | Dynegy Inc. Deferred Compensation Plan for Certain Directors (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2000 of Dynegy Inc., File No. 1-15659). |
| 10.13 | Dynegy Inc. 401(k) Savings Plan, as amended and restated effective January 1, 2002 (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 383-76570). |
| 10.14 | First Amendment to the Dynegy Inc. 401(k) Savings Plan, effective February 11, 2002 (incorporated by reference to Exhibit 10.19 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.15 | Second Amendment to the Dynegy Inc. 401(k) Savings Plan, effective January 1, 2002 (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |

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| 10.16 | Third Amendment to the Dynegy Inc. 401(k) Savings Plan, effective October 1, 2003 (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.17 | Amendment to the Dynegy Inc. 401(k) Savings Plan, effective January 1, 2004 (incorporated by reference to Exhibit 10.18 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.18 | Dynegy Inc. 401(k) Savings Plan Trust Agreement (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76570). |
| 10.19 | Dynegy Inc. Deferred Compensation Plan (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080). |
| 10.20 | Dynegy Inc. Deferred Compensation Plan Trust Agreement (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-76080). |
| 10.21 | Dynegy Inc. Short-Term Executive Stock Purchase Loan Program (incorporated by reference to Exhibit 10.19 to the Annual Report on Form 10-K for the Year Ended December 31, 2001 of Dynegy Inc., File No. 1-15659). |
| 10.22 | Dynegy Inc. Deferred Compensation Plan for Certain Directors (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.23 | Dynegy Inc. Executive Severance Pay Plan, as amended effective September 30, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.24 | Second Supplement to the Dynegy Inc. Executive Severance Pay Plan (incorporated by reference to Exhibit 10.28 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |
| **10.25 | First Amendment to The Dynegy Inc. Executive Severance Pay Plan effective May 19, 2004. |
| 10.26 | Dynegy Inc. Mid-Term Incentive Performance Award Program (incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.27 | Dynegy Northeast Generation, Inc. Savings Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 of Dynegy Inc., Registration No. 333-111985). |
| 10.28 | Amendment to the Dynegy Northeast Generation, Inc. Savings Incentive Plan, effective January 1, 2004 (incorporated by reference to Exhibit 10.31 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.29 | Dynegy Inc. Severance Pay Plan, as amended effective September 30, 2003 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.30 | Lease Agreement entered into on June 12, 1996 between Metropolitan Life Insurance Company and Metropolitan Tower Realty Company, Inc., as landlord, and NGC Corporation, as tenant (incorporated by reference to Exhibit 10.69 to the Registration Statement on Form S-4 of Midstream Combination Corp., Registration No. 333-09419). |

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| 10.31 | First Amendment to Lease Agreement entered into on June 12, 1996 between Metropolitan Life Insurance Company and Metropolitan Tower Realty Company, Inc., as landlord, and NGC Corporation, as tenant (incorporated by reference to Exhibit 10.70 to the Registration Statement on Form S-4 of Midstream Combination Corp., Registration No. 333-09419). |
| *10.32 | Master Natural Gas Liquids Purchase Agreement, dated as of September 1, 1996, between Warren Petroleum Company, Limited Partnership and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 1996 of NGC Corporation, File No. 1-11156). |
| 10.33 | Amended and Restated Credit Agreement dated as of May 28, 2004 among Dynegy Holdings Inc., as Borrower, Dynegy Inc., as Parent Guarantor, the Other Guarantors Party Thereto, the Lenders Party Thereto and Various Other Parties Thereto (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 1, 2004, File No. 1-15659). |
| 10.34 | Shared Security Agreement, dated April 1, 2003, among Dynegy Holdings, Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.32 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659). |
| 10.35 | Non-Shared Security Agreement, dated April 1, 2003, among Dynegy Inc., various grantors named therein and Bank One, N.A. as collateral agent (incorporated by reference to Exhibit 10.33 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659). |
| 10.36 | Collateral Trust and Intercreditor Agreement, dated as of April 1, 2003, among Dynegy Holdings Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.34 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659). |
| 10.37 | Amendment No. 1 to Collateral Trust and Intercreditor Agreement, dated as of May 28, 2004, among Dynegy Holdings Inc., various grantors named therein, JPMorgan Chase Bank, as collateral agent, Wilmington Trust Company, as corporate trustee, and John M. Beeson, Jr., as individual trustee (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2004 of Dynegy Inc., File No. 1-15659). |
| 10.38 | Series B Preferred Stock Exchange Agreement dated as of July 28, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.39 | Indemnity Agreement dated August 11, 2003 among Dynegy Inc., Dynegy Holdings Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.40 | Intercreditor Agreement dated August 11, 2003 among Dynegy Holdings Inc., various grantors named therein, Wilmington Trust Company, as corporate trustee, John M. Beeson, Jr., as individual trustee, Bank One, NA, as collateral agent, and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.41 | Second Lien Shared Security Agreement dated August 11, 2003 among Dynegy Holdings Inc., various grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |

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| 10.42 | Second Lien Non-Shared Security Agreement dated August 11, 2003 among Dynegy Inc., various grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.43 | Purchase Agreement dated August 1, 2003 among Dynegy Inc., Dynegy Holdings Inc. and the initial purchasers named therein (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.44 | Purchase Agreement dated August 1, 2003 among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659). |
| 10.45 | Purchase Agreement dated September 30, 2003 among Dynegy Holdings Inc., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K of Dynegy Inc. filed on October 15, 2003, File No. 1-15659). |
| 10.46 | Power Purchase Agreement dated September 30, 2004 between Illinois Power Company and Dynegy Power Marketing, Inc. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2004 of Dynegy Inc., File No. 1-15659). |
| 10.47 | Escrow Agreement dated as of September 30, 2004 among Illinova Corporation, Ameren Corporation and JPMorgan Chase Bank, as escrow agent (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended September 30, 2004 of Dynegy Inc., File No. 1-15659). |
| **10.48 | Stock Purchase Agreement dated as of November 1, 2004 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. |
| **10.49 | Amendment to Stock Purchase Agreement (Special Payroll Payment) dated as of January 28, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. |
| **10.50 | Amendment to Stock Purchase Agreement dated as of January 31, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. |
| **10.51 | Amendment to Stock Purchase Agreement (Luz Sale) dated as of January 31, 2005 among Dynegy New York Holdings Inc., Exelon SHC, Inc., Exelon New England Power Marketing, L.P. and ExRes SHC, Inc. |
| **10.52 | Tenth Amendment to Amended and Restated Base Gas Sales Agreement, dated as of June 29, 2001, by and between Enron North America Corp. and Sithe/Independence Power Partners, L.P. |
| **10.53 | Power Purchase Agreement dated as of November 17, 2004, between Dynegy Power Marketing, Inc., as seller, and Constellation Energy Commodities Group, Inc., as purchaser. |
| **10.54 | Assignment and Assumption Agreement dated as of November 17, 2004 between Dynegy Power Marketing, Inc. and Constellation Energy Commodities Group, Inc. |
| 14.1 | Dynegy Inc. Code of Ethics for Senior Financial Professionals (incorporated by reference to Exhibit 14.1 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003 of Dynegy Inc., File No. 1- 15659). |
| **21.1 | Subsidiaries of the Registrant. |
| **23.1 | Consent of PricewaterhouseCoopers LLP. |

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| **23.2 | Consent of PricewaterhouseCoopers LLP (West Coast Power LLC). |
| **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. |

* Exhibit omits certain information that we have filed separately with the SEC pursuant to a confidential treatment request pursuant to Rule 406 promulgated under the Securities Act of 1933, as amended.

** Filed herewith

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

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## 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, thereunto duly authorized.

DYNEGY INC.

Date: March 11, 2005

By: /s/ BRUCE A. WILLIAMSON

**Bruce A. Williamson**

**President, Chief Executive Officer and**

**Chairman of the Board**

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

| | | |
|---|---|---|
| /s/ BRUCE A. WILLIAMSON<br>**Bruce A. Williamson** | President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer) | March 11, 2005 |
| /s/ NICK J. CARUSO | | |