UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 2

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

For the fiscal year ended December 31, 2003

¨ **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	**(I.R.S. Employer**
of incorporation or organization)	**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)

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	

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, 2003, computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date, was $1,155,609,441, 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, 279,871,186 shares outstanding as of February 23, 2004; Class B common stock, no par value per share, 96,891,014 shares outstanding as of February 23, 2004.

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 2004 Annual Meeting of Shareholders, which will be filed not later than 120 days after December 31, 2003.

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DYNEGY INC. FORM 10-K/A

INTRODUCTORY NOTE

Dynegy Inc. is filing this Amendment No. 2 on Form 10-K/A (Amendment No. 2) to reflect the effect of the following items on our historical consolidated financial statements and related information, as reported in our Annual Report on Form 10-K for the fiscal year ended December 31, 2003, which was originally filed on February 27, 2004 (the Original Filing):

An increase of $139 million to the $242 million goodwill impairment charge originally recorded in the fourth quarter 2003 and a previously unrecorded after-tax asset impairment charge of $120 million, in the fourth quarter 2003, each associated with the sale of Illinois Power and

A $154 million decrease to our deferred tax liability at December 31, 2003 resulting from our tax basis balance sheet review.

The aforementioned items are discussed in more detail in the Explanatory Note to the accompanying consolidated financial statements beginning on page F-8. The following Items of the Original Filing are amended by this Amendment No. 2:

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

Item 9A. Controls and Procedures

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

Unaffected items have not been repeated in this Amendment No. 2.

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 2, INCLUDING THE FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER THE DATE OF THE ORIGINAL FILING. SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE FEBRUARY 27, 2004, INCLUDING OUR

QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

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DYNEGY INC.

FORM 10-K/A

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PART I

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 2, INCLUDING THE FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER THE DATE OF THE ORIGINAL FILING. SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE FEBRUARY 27, 2004, INCLUDING OUR QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

DEFINITIONS

As used in this Amendment No. 2, the abbreviations contained herein have the meanings set forth in the glossary beginning on page F-88. Additionally, the terms Dynegy, we, us and our refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

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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.

As discussed in the Explanatory Note to the accompanying Consolidated Financial Statements, the accompanying Consolidated Financial Statements have been restated since the date of the Original Filing. Please read the Explanatory Note to the accompanying Consolidated Financial Statements 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,				
	2003	2002	2001	2000	1999
	(in millions, except per share data) (Restated)				
Statement of Operations Data (1):					
Revenues	$ 5,787	$ 5,326	$ 9,124	$ 9,715	$ 4,821
General and administrative expenses	(366)	(325)	(420)	(312)	(208)
Depreciation and amortization expense	(454)	(466)	(452)	(386)	(114)
Asset impairment, abandonment and other charges	(200)	(190)			
Goodwill impairment	(311)	(814)			
Operating income (loss)	(569)	(1,058)	971	770	185
Interest expense	(509)	(297)	(255)	(247)	(77)
Income tax expense (benefit)	(246)	(352)	368	230	45
Net income (loss) from continuing operations	(688)	(1,190)	479	417	90
Income (loss) on discontinued operations (3)	(19)	(1,154)	(82)	27	44
Cumulative effect of change in accounting principles	40	(234)	2		
Net income (loss)	$ (667)	$ (2,578)	$ 399	$ 444	$ 134
Net income (loss) available to common stockholders	346	(2,908)	357	409	134
Earnings (loss) per share from continuing operations	$ 0.79	$ (4.16)	$ 1.29	$ 1.20	$ 0.39
Net income (loss) per share	0.84	(7.95)	1.05	1.29	0.58
Shares outstanding for diluted EPS calculation	423	370	340	315	230
Cash dividends per common share	$	$ 0.15	$ 0.30	$ 0.25	$ 0.04
Cash Flow Data:					
Cash flows from operating activities	$ 876	$ (25)	$ 550	$ 420	$ 40
Cash flows from investing activities	(266)	677	(3,828)	(1,539)	(391)
Cash flows from financing activities	(900)	(44)	3,450	1,131	399
Cash dividends or distributions to partners, net		(55)	(98)	(112)	(8)
Capital expenditures, acquisitions and investments	(338)	(981)	(4,687)	(2,415)	(521)

	December 31,				
	2003	2002	2001	2000	1999
			(in millions) (Restated)		
Balance Sheet Data (2):					
Current assets	$ 3,030	$ 7,586	$ 8,956	$ 10,827	$ 2,658
Current liabilities	2,576	6,748	8,538	10,286	2,467
Property, plant and equipment, net	8,203	8,458	9,269	7,148	2,155
Total assets	12,961	20,029	25,083	22,572	6,491
Long-term debt (excluding current portion)	5,893	5,454	5,016	3,754	1,372
Notes payable and current portion of long-term debt	331	861	458	118	192
Non-recourse debt					35
Serial preferred securities of a subsidiary	11	11	46	46	
Subordinated debentures		200	200	300	200
Series B Preferred Stock (4)		1,212	882		
Series C convertible preferred stock	400				
Minority interest (5)	121	146	1,040	1,022	
Capital leases not already included in long-term debt		15	29	15	
Total equity	1,947	2,203	4,894	3,405	1,196

(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 15 Redeemable Preferred Securities Series B Preferred Stock beginning on page F-54 for further discussion.

(5) The 2001 and 2000 amounts include amounts relating to the Black Thunder transaction discussed in Note 12 Debt Black Thunder Secured Financing beginning on page F-45.

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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.

PLEASE NOTE THAT THE INFORMATION CONTAINED IN THIS AMENDMENT NO. 2, INCLUDING THE FINANCIAL STATEMENTS AND THE NOTES THERETO, DOES NOT REFLECT EVENTS OCCURRING AFTER THE DATE OF THE ORIGINAL FILING. SUCH EVENTS INCLUDE, AMONG OTHERS, THE EVENTS DESCRIBED IN OUR QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004 AND THE EVENTS SUBSEQUENTLY DESCRIBED IN OUR CURRENT REPORTS ON FORM 8-K. FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE FEBRUARY 27, 2004, INCLUDING OUR QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

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 three areas of the energy industry: power generation; natural gas liquids; and regulated energy delivery. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. We also separately report the results of our customer risk management business, which primarily consists of our four remaining power tolling arrangements and related gas transportation contracts, as well as legacy gas and power trading positions. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and 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 four 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 summary of our current liquidity position and items that could impact our liquidity position in 2004 and beyond. Please note that this Overview section is merely a summary and should be read together with the remainder of Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, as well as the 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. 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 and, to a lesser extent, natural gas, 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. Please read Liquidity and Capital Resources Internal Liquidity Sources Cash Flows from Operations beginning on page 16 for a discussion of our views on the current pricing environment and its anticipated long-term recovery.

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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 other costs through disciplined management and safe, efficient operations;

- our ability to optimize our assets through forward 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, particularly the CDWR and Illinois Power power purchase agreements that are scheduled to expire at the end of 2004. In connection with our recently announced agreement to sell Illinois Power to Ameren, we agreed, conditioned upon the closing of the sale, to sell 2,800 MWs of capacity and up to 11.5 million MWh of energy to Illinois Power at fixed prices for two years beginning in January 2005. The closing of the sale to Ameren, which is expected by the end of 2004, is subject to receipt of required regulatory approvals and other closing conditions. Please read Results of Operations Segment Discussion 2004 Outlook REG Outlook beginning on page 34 and Note 23 Subsequent Event beginning on page F-86 for further discussion.

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 the relationship between the two, commonly referred to as the frac spread. In our upstream business, we continued the restructuring of our contract portfolio in 2003. As a result, our current contract mix has reduced our exposure to frac spread risk. Please read Item 1. Business Segment Discussion Natural Gas Liquids Upstream Business beginning on page 7 of our Original Filing for a detailed discussion of our current upstream contract mix.

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 other costs through disciplined management and safe, efficient operations;

- reduced market liquidity and our obligation to post collateral to 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 low frac spread environment and the resulting reduction in volumes available for fractionation, distribution and marketing;

the petrochemical industry s need for and utilization of our natural gas liquids feedstocks and related natural gas liquids facilities;

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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 is currently comprised of our Illinois Power subsidiary. 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.

Illinois Power is a regulated utility that serves more than 590,000 electricity customers and nearly 415,000 natural gas customers in portions of northern, central and southern Illinois. We generate earnings and cash flows in this business through sales of electric and gas service to residential, commercial and industrial customers.

The earnings and cash flows generated by this business are primarily driven by the volumes of electricity and natural gas that we sell and deliver. In terms of costs, retail electric rates are frozen through 2006, and gas costs are passed through to customers. The primary factors impacting sales volumes include:

weather and its effect on demand for our services, particularly with respect to residential electric customers;

the number of customers that choose another retail electric provider under the Illinois Customer Choice Law;

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

general economic conditions and the resulting effect on demand for our services, particularly with respect to commercial and industrial customers.

We recently entered into an agreement to sell Illinois Power and our 20% interest in the Joppa power generation facility to Ameren for $2.3 billion. The transaction is expected to close by the end of 2004, subject to the receipt of required regulatory approvals and other closing conditions. Please read Note 23 Subsequent Event beginning on page F-86 for further discussion.

Customer Risk Management. Our customer risk management business primarily consists of our four remaining power tolling arrangements and related gas transportation contracts, as well as our legacy gas and power trading positions. We have significant, long-term fixed obligations associated with our tolling and gas transportation arrangements, which obligations 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 tolling plants are located, as well as our ability to re-market the related capacity under the transportation arrangements. It also will be significantly impacted by our ability to restructure or terminate one or more of our 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 of our

Original Filing for further discussion.

Corporate and Other. Beginning January 1, 2003, Corporate and 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 in 2003 as a result of our refinancing and restructuring activities and will continue to reflect our non-investment grade credit ratings;

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general and administrative costs, with respect to which we have implemented a number of initiatives expected to yield savings beginning in 2004; 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.

Liquidity. As of February 23, 2004, we had cash on hand of $397 million and available borrowing capacity of $866 million, for total liquidity of nearly $1.3 billion. During 2003, we substantially reduced our debt and other obligations while maintaining liquidity between $1.4 billion and $1.7 billion. Our ability to maintain our liquidity position in the future will depend on a number of factors, including our ability to consummate the Illinois Power sale to Ameren and, over the longer term, to generate cash flows from our asset-based energy businesses in relation to our substantial debt obligations and ongoing operating requirements.

For the next 12 months, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be insufficient to satisfy our capital expenditures, debt maturities, increased interest expenses and operating commitments. When combined with our cash on hand, proceeds from anticipated asset sales and capacity under our $1.1 billion revolving credit facility, however, we believe we have sufficient capital resources to satisfy these obligations during this period. To further our deleveraging efforts, we also intend to explore other capital-raising activities, including potential public or private equity issuances. In addition, we will seek to renew or replace our $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005. Our liquidity position will be materially adversely affected if we are unable to renew or replace this facility, with respect to which our ability to borrow and/or issue letters of credit could become increasingly important, on or before its scheduled maturity.

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 the restructuring work that we did during 2003 extended a substantial portion of our debt maturities from 2005-2006 to 2008 and beyond, positioning us to benefit from earnings and growth opportunities associated with this expected recovery in the U.S. power markets. Conversely, although depressed frac spreads have negatively impacted our NGL segment s downstream operations, our upstream business is currently operating in a relatively favorable pricing environment. Our future financial condition and results of operations will be materially affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant pricing deterioration in our NGL segment.

LIQUIDITY AND CAPITAL RESOURCES

Debt Maturities

During 2003, we consummated a series of refinancing and restructuring transactions comprised of the following:

Restructuring of $1.66 billion in credit facilities prior to their scheduled maturities, in connection with which we granted security interests in a substantial portion of the available assets and stock of our direct and indirect subsidiaries, excluding Illinois Power;

Issuance by DHI of $1.75 billion of senior notes at a weighted average interest rate of 9.71% and a weighted average yield to maturity of 9.65%, which notes are secured on a second priority basis by substantially the same collateral that secures the obligations under DHI s restructured credit facility;

Issuance by Dynegy of $225 million of convertible subordinated debentures at an interest rate of 4.75%, which debentures are convertible into shares of our Class A common stock at $4.1210 per share, subject to certain adjustments, and guaranteed on a senior unsecured basis by DHI;

The purchase of approximately $282 million of DHI s $300 million 8.125% Senior Notes due 2005, virtually all of DHI s $150 million 6 3/4% Senior Notes due 2005 and approximately $177 million of DHI s $200 million 7.450% Senior Notes due 2006; and

Restructuring of the $1.5 billion in Series B Mandatorily Convertible Redeemable Preferred Stock previously held by a ChevronTexaco subsidiary, which we refer to as the Series B Preferred Stock. Under this restructuring, which we refer to as the Series B Exchange, the Series B Preferred Stock was exchanged for $225 million in cash, $225 million principal amount of our Junior Unsecured Subordinated Notes due 2016, which we refer to as the Junior Notes, and 8 million shares of our Series C Mandatorily Redeemable Convertible Preferred Stock due 2033 (liquidation preference $50 per share), which we refer to as the Series C preferred stock. The Series C preferred stock generally is convertible into shares of our Class B common stock at $5.78 per share, subject to shareholder approval, which approval we intend to solicit at our 2004 annual shareholder meeting.

We used the net cash proceeds from these transactions, together with approximately $300 million of cash on hand and additional funds received in the form of returned prepayments from ChevronTexaco under the Series B Exchange, to make the $225 million Series B Exchange payment, to purchase the DHI senior notes and to otherwise reduce our 2005 debt maturities as follows:

Prepay in full the $200 million Term A loan outstanding under DHI s restructured credit facility;

Prepay in full the $360 million Term B loan outstanding under DHI s restructured credit facility;

Prepay in full the $696 million of debt outstanding under the Black Thunder secured financing; and

Prepay in full the $170 million capital lease obligation associated with our CoGen Lyondell power generating facility.

For a more complete description of these transactions, including the increasing interest rate and conversion features of the securities issued in connection with the Series B Exchange, please read Note 11 Refinancing and Restructuring Transactions beginning on page F-39.

As a result of these transactions, we extended a substantial portion of our 2005-2006 maturities to 2008 and beyond. Our aggregate maturities for long-term debt are as follows:

Period	Total	Illinois Power (1)	Total Less Illinois Power (1)
		(in millions)	
2004 (2)	$ 331	$ 157	$ 174
2005	258	156	102
2006	130	86	44
2007	270	86	184

2008	311	86	225
Thereafter	4,924	1,366	3,558

(1) If the Ameren transaction closes as expected before the end of 2004, Ameren will assume Illinois Power s then outstanding indebtedness. Please read Note 12 Debt beginning on page F-41 for further discussion of our outstanding debt.

(2) Included in Illinois Power s 2004 maturities of $157 million is $71 million related to the Tilton capital lease. In October 1999, Illinois Power entered into a sublease with DMG pursuant to which DMG is obligated to make all payments under the lease.

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One important near-term maturity that remains is our $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005. While we currently have no drawn amounts under this facility, our ability to borrow and/or issue letters of credit under a revolving credit facility could become increasingly important, particularly if we are unable to generate operating cash flows relative to our substantial debt obligations and ongoing operating requirements or to realize the asset sale proceeds we anticipate. We currently intend to renew or replace this facility during 2004, although we cannot guarantee that we will be successful.

While our restructuring and refinancing transactions have extended our significant debt maturities, they also resulted in significantly increased interest expenses, as further described under Results of Operations Interest Expense beginning on page 32. We also are subject to the more restrictive covenants that are contained in the related transaction agreements. Specifically, among other limitations, these covenants limit our ability to receive payments from DHI for the purpose of paying dividends on our common stock and otherwise, limit DHI s ability to incur additional indebtedness other than for refinancing purposes and require that a significant portion of proceeds from specified asset sales and equity issuances be used to pay down outstanding indebtedness. For example, upon closing of the agreed sale of Illinois Power to Ameren, we must use 75% of the net cash proceeds to repay the Junior Notes. We are required to use 25% of the net cash proceeds of the sale to reduce permanently or cash collateralize the commitments under the facility, subject to certain exceptions, to the extent the Junior Notes are repaid up to $100 million. If the Junior Notes are not outstanding, 100% of the net cash proceeds from asset sales are required to be used, subject to certain exceptions, to reduce the commitments under the revolver. While we are currently in compliance with these restrictive covenants, our future financial condition and results of operations could be significantly affected by our ability to execute our business and financial strategies within the confines of these restrictive covenants.

The following table depicts our consolidated third-party debt obligations, including the principle-like maturities associated with the DNE leveraged lease, and the extent to which they are secured as of December 31, 2003 and 2002:

	December 31, 2003	December 31, 2002
	(in millions)	
First Secured Obligations		
Dynegy Holdings Inc.	$ 1,127	$ 2,440
Dynegy Inc.		360
Illinois Power (1)	1,967	2,092
Total First Secured Obligations	3,094	4,892
Second Secured Obligations	1,750	
Unsecured Obligations	2,160	2,266
Subtotal	7,004	7,158
Preferred Obligations	411	1,711
Total Obligations	$ 7,415	$ 8,869
Less: DNE Lease Financing	(758)	(746)
Less: Preferred Obligations	(411)	(1,711)
Other (2)	(22)	(97)
Total Notes Payable and Long-term Debt	$ 6,224	$ 6,315

(1) Ameren will assume Illinois Power s debt obligations upon closing of our agreed sale of Illinois Power, which is anticipated to occur before the end of 2004, subject to receipt of required regulatory approvals and other closing conditions. Please read Note 23 Subsequent Event

beginning on page F-86 for further discussion.

(2) Consists of net discounts on debt (totaling $12 million and $16 million at December 31, 2003 and December 31, 2002, respectively) 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. At December 31, 2002, the Tilton lease was off-balance sheet as it was accounted for as an operating lease.

Collateral Postings

We have substantially reduced our collateral postings since the end of 2002. As detailed in the table below, total collateral postings are down by approximately $704 million as of February 23, 2004. The reduction is particularly pronounced in our CRM segment, which we commenced exiting in October 2002. Our collateral postings are down in that segment by more than $634 million since year-end 2002 and by more than $800 million from their peak at September 30, 2002.

The following table summarizes our consolidated collateral postings to third parties by operating division at February 23, 2004, December 31, 2003 and December 31, 2002:

	February 23, 2004	December 31, 2003	December 31, 2002
		(in millions)	
GEN	$ 146	$ 136	$ 168
CRM	172	121	806
NGL	144	179	166
REG	42	38	28
Other	8	8	48
Total	$ 512	$ 482	$ 1,216

As described in Note 12 Debt DHI Credit Facility beginning on page F-42, we incur a 0.15% fronting fee upon the issuance of letters of credit under our restructured credit facility. A letter of credit fee is also payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 4.75% of such undrawn amount. To reduce these fees, we have used, and expect to continue to use, cash on hand, as opposed to letters of credit, to satisfy our future collateral obligations where practicable. Our ability to continue this strategy depends to a large extent on the creditworthiness of our counterparties and the availability of cash on hand.

Going forward, we expect counterparties collateral demands to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their view of our creditworthiness. 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 12 months. Over the longer term, we expect to achieve incremental reductions associated with the completion of our exit from the customer risk management business. Please see Results of Operations 2004 Outlook CRM Outlook beginning on page 35 for a discussion of the expected collateral roll-off from this business.

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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, 2003. Cash obligations reflected are not discounted and do not include related interest, accretion or dividends.

	Payments Due by Period						
	Total	2004	2005	2006	2007	2008	Thereafter
	(in millions)						
Long-Term Debt (including Current Portion)	$ 6,153	$ 260	$ 258	$ 130	$ 270	$ 311	$ 4,924
Capital Leases	81	81					
Redeemable Preferred Securities	411						411
Operating Leases	1,588	81	81	81	127	147	1,071
Unconditional Purchase Obligations	53	53					
Capacity Payments	2,852	259	243	231	232	232	1,655
Conditional Purchase Obligations	766	222	158	207	127	38	14
Pension Funding Obligations	111	8	57	46			
Other Long-Term Obligations	7	6	1				
Total Contractual Obligations	$ 12,022	$ 970	$ 798	$ 695	$ 756	$ 728	$ 8,075

Long-Term Debt (including Current Portion). Total amounts of Long-Term Debt (including Current Portion) are included in the December 31, 2003 Consolidated Balance Sheet. For additional explanation, please read Note 12 Debt beginning on page F-41.

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-34 for further discussion of these joint ventures.

Capital Leases. Capital leases consist of our Tilton capital lease obligation. Of the $81 million obligation above, $71 million is included in the December 31, 2003 Consolidated Balance Sheet as a component of Notes Payable and Current Portion of Long-Term Debt. The $10 million difference will be accreted over the remaining term of the capital lease through a charge to interest expense with a corresponding increase to short-term debt. We began reflecting the Tilton facility and the related debt in our consolidated balance sheets in September 2003 as a result of our delivery of a notice of our intent to purchase the related turbines upon the lease expiration in September 2004. For additional explanation, please read Note 12 Debt Tilton Capital Lease beginning on page F-46.

Redeemable Preferred Securities. Total amounts of Redeemable Preferred Securities are included in the December 31, 2003 Consolidated Balance Sheet. For additional explanation, please read Note 15 Redeemable Preferred Securities beginning on page F-53.

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 13. Amounts also include minimum lease payment obligations associated with office and office equipment leases.

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Unconditional Purchase Obligations. Amounts include natural gas and power purchase agreements. For additional information, please read Note 17 Commitments and Contingencies Other Commitments and Contingencies Purchase Obligations beginning on page F-67.

Capacity Payments. Capacity payments include future payments aggregating $2.3 billion under our four remaining power tolling arrangements, as further described in Item 1. Business Segment Discussion Customer Risk Management beginning on page 18 of our Original Filing. This amount includes the fixed payments associated with a derivative instrument related to the Sithe tolling arrangement, which is reflected at its fair value on our Consolidated Balance Sheet in Risk-Management Liabilities, as well as amounts relating to contracts that are accounted for on an accrual basis. At December 31, 2003, approximately $325 million of fixed payments have been reflected in the fair value of the Sithe derivative instrument. We are exploring opportunities to renegotiate or terminate one or more of these arrangements on terms we consider economical. Please read Results of Operations 2004 Outlook CRM Outlook beginning on page 35 for further discussion of the anticipated effects of these arrangements on our future results of operations.

In addition, capacity payments include fixed obligations associated with transmission, transportation and storage arrangements totaling approximately $573 million.

Conditional Purchase Obligations. Amounts include our obligations as of December 31, 2003 to purchase 14 gas-fired turbines. The purchase orders include milestone requirements by the manufacturer and provide us with the ability to cancel each discrete purchase order commitment in exchange for a fee, which escalates over time. The $479 million included herein assume all 14 turbines will be purchased. In February 2004, we terminated our conditional purchase obligation related to these gas fired turbines as part of a comprehensive settlement agreement with the manufacturer. No cash, other than $11 million previously paid to the manufacturer as a deposit, is expected to be provided as consideration for the termination.

Amounts also include $205 million related to Illinois Power s long-term power purchase agreement with AmerGen. The agreement was entered into in connection with the sale of Illinois Power s former Clinton nuclear generation facility in December 1999. Illinois Power is obligated to purchase a predetermined percentage of Clinton s electricity output through 2004 at fixed prices that exceed current and projected wholesale prices. At the time of the sale of the nuclear generation facility, a liability was recorded related to the above-market portion of this purchase agreement, which is being amortized through 2004, based on the expected energy to be purchased from AmerGen.

Amounts also include $136 million related to our co-sourcing agreement with Accenture Ltd. This 10-year agreement may be cancelled after two years upon the payment of a termination fee.

Pension Funding Obligations. Amounts include estimated defined benefit pension funding obligations for 2004 ($8 million), 2005 ($57 million) and 2006 ($46 million). Although we expect to incur significant funding obligations subsequent to 2006, such amounts have not been included in this table because our estimates are imprecise. Under the terms of the sale of Illinois Power to Ameren, we will be required to accelerate certain of our 2005 cash funding requirements at closing of the sale.

Other Long-Term Obligations. Amounts include decommissioning costs related to Illinois Power s sale of its Clinton nuclear facility in 1999 and decontamination and decommissioning charges associated with Illinois Power s use of a facility that enriched uranium for the Clinton Power Station.

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Contingent Financial Obligations

The following table provides a summary of our contingent financial obligations as of December 31, 2003 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)	$ 188	$ 188	$	$	$
Surety Bonds (2)(4)	80	80			
Guarantees (3)	131	13	26	26	66
Total Financial Commitments	$ 399	$ 281	$ 26	$ 26	$ 66

(1) Amounts include outstanding letters of credit.
(2) Surety bonds are generally on a rolling 12-month basis.
(3) Amounts include two charter party agreements relating to VLGCs previously utilized in our global liquids business sub-chartered to a wholly owned subsidiary of Transammonia Inc. The terms of the sub-charters are identical to the terms of the original charter party agreements. We are currently in negotiations with the owners of the VLGCs and their lenders to obtain a novation/release of the two charter party agreements and a release of our guarantees.
(4) $45 million of the surety bonds were supported by collateral.

Off-Balance Sheet Arrangements

In September 2003, we delivered notice of our intent to exercise our option to purchase the Tilton assets upon the expiration of the operating lease in September 2004. As a result of this action, we began accounting for the related lease obligation, which we formerly reported as an off-balance sheet arrangement, as a capital lease. Following is a discussion of our remaining off-balance sheet arrangement.

DNE Leveraged Lease. As described in Item 1. Business Segment Discussion Power Generation Northeast region Northeast Power Coordinating Council (NPCC) beginning on page 5 of our Original Filing, we established our presence in the Northeast region by acquiring the DNE power generating facilities in January 2001 for $950 million from Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. and Niagara Mohawk Power Corporation.

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 maximize the value of the facilities 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, 2003, future lease payments are $60 million for each year 2004 through 2006, with $1.3 billion in the aggregate due from 2007 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, 2003, the present value (discounted at 10%) of future lease payments was $758 million.

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

	2003	2002	2001
		(in millions)	
Lease Expense	$ 50	$ 50	$ 34
Lease Payments (Cash Flows)	$ 60	$ 60	$ 30

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, 2003, the termination payment at par would be $997 million 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

In connection with our restructuring, we have undertaken various efforts to tightly manage costs and capital expenditures. We had approximately $333 million in capital expenditures during 2003. This is a significant reduction from the approximately $947 million in capital expenditures during 2002 and reflects our efforts to improve our capital efficiency without compromising the operational integrity of our facilities. Our 2003 capital spending by segment was as follows (in millions):

GEN	$ 151
NGL	51
REG	126
Other	5
Total	$ 333

Capital spending in our GEN segment primarily consisted of maintenance capital projects, as well as approximately $40 million spent on completing the construction of the Rolling Hills facility, which began commercial operation during the summer of 2003. Capital spending in our

NGL segment primarily related to maintenance capital projects and wellconnects, as well as $8 million in development capital at our Cedar Bayou Fractionators, LP. Capital spending in our REG segment primarily related to projects intended to maintain system reliability and new business services.

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We expect capital expenditures for 2004 to approximate $375 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 2004 are as follows (in millions):

GEN	$ 150
NGL	75
REG	140
Other	10
Total	$ 375

Increased capital spending in the NGL segment is primarily due to $20 million for gathering system expansion, additional compression and plant de-bottlenecking in North Texas related to increased gas from the Barnett Shale formation and $7 million for a significant upgrade in compression technology and efficiencies at our Monument gas processing plant.

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 $45 million in 2003 and are expected to be $67 million in 2004.

Our capital expenditures in 2004 and beyond will be limited by negative covenants contained in our restructured credit agreements. These covenants place specific dollar limitations on our ability to incur capital expenditures except in our REG segment. Please read Note 11 Refinancing and Restructuring Transactions beginning on page F-39 for further discussion of these transactions.

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, changes in law resulting in loss of tax-exempt status on certain bond issuances, 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 have not executed any transactions that require us to issue equity based on credit ratings or other trigger events.

Commitments and Contingencies

Please read Note 17 Commitments and Contingencies beginning on page F-56, which is incorporated herein by reference, for a discussion of our commitments and contingencies.

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 the dividend restrictions contained in our financing agreements. We have, however, continued to make the required dividend payments on our outstanding trust preferred securities. Please read Note 11 Refinancing and Restructuring Transactions beginning on page F-39 for a discussion of the dividend restrictions contained in our financing agreements.

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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 15 Redeemable Preferred Securities beginning on page F-53 for further discussion of this non-cash implied dividend. 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 $8 million in dividends during the year ended December 31, 2003. We did not make any dividend payments on the Series C preferred stock during the year ended December 31, 2003. However, we made the first semi-annual dividend payment of $11 million on February 11, 2004, as a result of which capacity under our revolving credit facility was reduced by $11 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 15 Redeemable Preferred Securities beginning on page F-53 for further discussion.

Internal Liquidity Sources

Our primary internal liquidity sources are cash flows from operations, cash on hand and available capacity under our $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005.

Cash Flows from Operations. We had operating cash flows of $876 million in 2003, which included approximately $500 million associated with our CRM business and $110 million from a federal income tax refund, neither of which is expected to be repeated in 2004. For 2004, we have projected operating cash flows of $150 to $185 million. This projection, which is subject to change based on a number of factors, many of which are beyond our control, reflects $825 to $850 million in forecasted operating cash flows from our GEN, NGL and REG business segments, offset by projected cash outflows of $180 to $185 million from our customer risk management business and $485 to $490 million in corporate-level expenses, including interest.

Our operating cash flows are significantly impacted by commodity prices, particularly in our power generation and NGL businesses. Although the depressed frac spread is negatively impacting our NGL segment s downstream operations, our upstream business is currently operating in, and is expected to continue to operate in, a favorable pricing environment. However, our power generation business is currently operating in a relatively weak pricing environment due to overcapacity in the markets we serve. Management believes, however, that the U.S. power markets will improve and reach a state of equilibrium a condition where supply equals demand plus a reasonable reserve over the longer term. This belief is based on various market indicators, including projected supply-demand imbalances and the perceived reaction to the risk of supply interruption. If equilibrium were to occur in one or more of the regions in which we operate, we expect that the pricing environment in the applicable regions would significantly improve. As a result, baseload and dual-fuel plants would produce higher earnings and cash flows and peaking plants would be more economical to operate.

As described above, much of the restructuring work that we have done has extended our significant debt maturities to 2008 and beyond, positioning us to benefit from this expected long-term recovery in the U.S. power markets. 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 price deterioration in the upstream portion of the NGL segment. Please read Item 1. Business Segment Discussion Power Generation beginning on page 2 of our Original Filing for a discussion of our current views on supply and demand in the regions where our power generation business operates.

Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to tightly manage our operating costs and to renew or replace our CDWR agreement. With respect to costs, we launched a value creation project in early 2003, a company-wide initiative focused on identifying opportunities to improve our operational efficiencies. In connection with this project, we have undertaken a number of initiatives,

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including our October 2003 co-sourcing agreement with Accenture Ltd. and a centralized procurement program, designed to reduce costs across the company. We also have sharpened our focus on reducing operating costs and, in January 2004, entered into a new rail transportation contract that we anticipate will reduce the fees associated with fuel procurement at our coal-fired generation facilities. Our ability to achieve these cost savings in the face of industry-wide increases in labor and benefits costs will impact our future operating cash flows.

In addition, our CDWR power purchase agreement expires by its terms on December 31, 2004. Our share of West Coast Power s revenues under this agreement in 2003 totaled $305 million. If we are unable to renew or replace this agreement, we would seek to sell the associated energy and capacity into the open market, where our operating cash flows would be dependent on then prevailing market prices. We expect that the generating facilities supporting the CDWR contract would be significantly less profitable as merchant facilities.

Cash on Hand. At February 23, 2004 and December 31, 2003, we had cash on hand of $397 million and $477 million, respectively. We intend to continue our disciplined cash management practices to maintain our cash position. For example, we have been, and intend to continue, substituting more cash as collateral with certain high-credit quality counterparties than letters of credit under our revolving credit facility. This has resulted in reduced letter of credit fees relative to cash interest income. However, unforeseen events such as legal judgments or regulatory requirements, as well as litigation settlements or contract terminations, could negatively impact our ability to do so.

Revolver Capacity. Our primary credit facility is DHI s $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005. We currently have no drawn amounts under this facility, although as of February 23, 2004, we had $222 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, particularly if we are unable to generate operating cash flows relative to our substantial debt obligations and ongoing operating requirements or to realize the asset sale proceeds we anticipate. We currently plan to pursue such a renewal or replacement during 2004, although we cannot guarantee that we will be successful in this pursuit. We expect to incur significant fees in connection with any such renewal or replacement. Please see Note 11 Refinancing and Restructuring Transactions Credit Facility Restructuring beginning on page F-39 for a discussion of the fees we incurred in connection with our April 2003 credit facility restructuring.

Current Liquidity. During 2003, we maintained a strong liquidity position, averaging total available liquidity of approximately $1.5 billion. The following table summarizes our consolidated credit capacity and liquidity position at February 23, 2004, December 31, 2003 and December 31, 2002:

	February 23, 2004	**December 31, 2003**	**December 31, 2002**
		(in millions)	
Total Revolver Capacity	$ 1,088(1)	$ 1,100(2)	$ 1,400
Outstanding Loans			(228)
Outstanding Letters of Credit Under Revolving Credit Facility	(222)	(188)	(872)
Unused Revolver Capacity	866	912	300
Cash (3)	397(4)	477	757
Liquid Inventory (5)			258
Total Available Liquidity	$ 1,263(6)	$ 1,389(6)	$ 1,315

(1)

The February 23, 2004 amount reflects $12 million of mandatory reductions of our revolving credit facility related to asset sales and dividend payments on the Series C preferred stock.

(2) Reflects the conversion of $200 million of credit capacity under the former DHI revolving credit facilities into the Term A loan in connection with the April 2003 restructuring of such facilities, as well as the May 2003 payment of the final $100 million then outstanding under Illinois Power s termed out revolving credit facility.

(3) Reflects $95 million repayment of Illinova senior notes on February 2, 2004.
(4) Includes approximately $40 million 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.
(5) Amounts reflected for 2003 and 2004 periods do not include liquid inventory, as we have sold the natural gas inventories that comprised that item and converted them to cash.
(6) Includes approximately $71 million and $17 million, respectively, of liquidity at Illinois Power. Please read Item 1. Business Regulation beginning on page 21 of our Original Filing for a discussion of ICC regulations that restrict our ability to receive cash dividends from Illinois Power. Please also read Note 23 Subsequent Event beginning on page F-86 for a discussion of our pending sale of Illinois Power to Ameren.

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. As indicated above, assuming continuation of the current commodity pricing environment, our estimated operating cash flows for 2004 will be insufficient to satisfy our capital expenditures, debt maturities, increased interest expenses and operating commitments. Accordingly, the receipt of proceeds from asset sales that we are currently pursuing or considering will significantly impact our near-term financial condition.

In February 2004, we entered into an agreement to sell Illinois Power and our 20% interest in the Joppa power generation facility to Ameren for $2.3 billion. Upon closing of the transaction, which is subject to regulatory approval and other closing conditions, we would receive $400 million in cash, subject to working capital adjustments, and Ameren would put $100 million in escrow, subject to full release to us on December 31, 2010 or earlier upon the occurrence of specified events. Please read Note 23 Subsequent Event beginning on page F-86 for further discussion of the transaction, which is expected to close before the end of 2004, and the required use of proceeds.

In an effort to maximize our return on investment and to further clarify our business strategy, we are pursuing or considering sales of other assets that we do not consider core to our operations. These assets primarily include our ownership interests in certain non-strategic and international power generation facilities, as further described in Item 1. Business Segment Discussion Power Generation beginning on page 2 of our Original Filing, as well as our minority ownership interests in a gas processing plant and Gulf Coast Fractionators, a partnership that owns a fractionator in Mont Belvieu. The sales of these non-core assets, together with other potential payments relating to our prior sale of the Hackberry LNG project, are expected to generate aggregate cash proceeds of $255 to $270 million in 2004. These aggregate proceeds include approximately $5.5 million in proceeds received in January 2004 in connection with the sale of our Jamaica investment. Generally, the aggregate projected earnings impact of these transactions is not considered material and is expected to be offset substantially by net gains on sale in 2004.

We are in the late stages of negotiations to sell our remaining interest in the Hackberry LNG project. Commercial conditions affecting projects of this type have reduced the value of our interest, which primarily included rights to future earnings from the project. As a result, we could agree to a sale of our interest at a price that would reduce the $255 to $270 million in anticipated sale proceeds above by $30 to $35 million.

Our desire or ability to effect these transactions is subject to a number of factors, many of which are beyond our control, including the market for the subject assets and investments and the receipt of any regulatory and other approvals that may be required. Accordingly, we cannot make any guarantees that these sales will be consummated or that the expected proceeds will be received. In addition, if the sales are consummated while the Junior Notes remain outstanding, we are required to use: (i) 75% of the net cash proceeds from the sale of Illinois Power to pay down the

Junior Notes and 25% of the net cash proceeds to reduce the commitments of the revolver; (ii) 25% of the net cash proceeds from other sales to pay down the Junior Notes; and (iii) 25% of the net cash proceeds from other sales to reduce permanently or cash collateralize the commitments under our revolving credit facility up to a maximum of $100 million. If the Junior Notes are not outstanding, 100% of the net cash proceeds from asset sales are required to be used, subject to certain exceptions, to reduce the commitments under the revolver. We intend to use the remaining proceeds to pay transaction fees and expenses and to repay other outstanding debt.

Although no other asset sales or related transactions have been specifically identified, we discuss and evaluate merger and acquisition activities as part of our ongoing business strategy.

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, we intend to explore additional capital-raising transactions both in the near- and longer term. These transactions could include public or private equity issuances. Our ability to issue public equity 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 equity issuance 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. Our ability to issue private equity could be similarly affected and, if such an issuance were completed, would likely be more costly, both in terms of required rates of return and other requirements typically associated with this type of transaction. Any issuance of equity likely would have other effects as well, including shareholder dilution.

The proceeds from any such issuance would be subject to the mandatory prepayment provisions of our revolving credit agreement and second secured senior notes indenture, which generally do not require prepayment for the first $250 million in proceeds, which may be used for repayment of the Junior Notes and for dollar-for-dollar commitment reduction under our revolving credit facility up to a maximum of $100 million. Please see Note 12 Debt DHI Credit Facility beginning on page F-42 for further discussion.

Conclusion

During 2003, we completed a series of refinancing and restructuring transactions that included sales of nearly $2.0 billion in DHI second priority senior secured notes and Dynegy convertible subordinated debentures. We used the net proceeds from these offerings, together with cash on hand, to repay approximately $2.0 billion in 2005-2006 debt maturities. We also made a $225 million cash payment to ChevronTexaco as part of the Series B Exchange. As a result of these transactions, we have extended a substantial portion of our debt maturities from 2005-2006 to 2008 and beyond and eliminated the uncertainty that surrounded the Series B Preferred Stock.

For the next 12 months, assuming continuation of the current commodity pricing environment, we expect that our operating cash flows will be insufficient to satisfy our capital expenditures, debt maturities, increased interest expenses and operating commitments. When combined with our cash on hand, proceeds from anticipated asset sales and capacity under our $1.1 billion revolving credit facility, however, we believe we have sufficient capital resources to discharge these obligations during this period. In order to further our deleveraging efforts, we also intend to explore other capital-raising activities, including potential public or private equity issuances. Our ability to raise additional funds may impact our ability to settle our significant ongoing litigation, as well as one or more of our four remaining power tolling arrangements, with respect to which we have substantial fixed payment obligations extending well into the future.

Over the longer term, our liquidity position and financial condition will be materially affected by a number of factors, including our ability to consummate the Illinois Power sale to Ameren and to generate cash flows from our asset-based energy businesses in relation to our debt and commercial obligations, including a substantial increase in interest expense, the fixed payment obligations associated with our CRM business and counterparty collateral requirements. The sale of Illinois Power would provide significant cash proceeds to repay outstanding debt and advance our business strategy of focusing on our unregulated energy businesses. Our future financial success is also substantially dependent on our ability to renew or replace our $1.1 billion revolving credit facility, which is scheduled to mature on February 15, 2005, with respect to which our ability to borrow and/or issue letters of credit could become increasingly important.

Our ability to generate operating cash flows from our asset-based energy businesses 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 and capital expenditures. 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 the restructuring work that we did in 2003 has extended our significant debt maturities from 2005-2006 to 2008 and beyond, positioning us to benefit from earnings and growth opportunities associated with this expected recovery in the U.S. power markets. Conversely, although depressed frac spreads have negatively impacted our NGL segment s downstream operations, our upstream business is currently operating in a relatively favorable pricing environment. Our future financial condition and results of operations will be materially affected if the U.S. power markets fail to recover in accordance with our expectations or if we experience significant pricing deterioration in the NGL segment.

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 2003, 2002 and 2001. At the end of this section, we have included our 2004 outlook for each segment.

As reflected in this report, we have changed our reporting segments. We historically 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 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. Other income (expense) items incurred by us on behalf of our subsidiaries are allocated directly to the four segments.

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 21 Segment Information beginning on page F-79 for a discussion of the impact of comparing segment results period over period. Regarding our results of operations for 2003, 2002 and 2001, 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 2003 period as compared to the 2002 and 2001 periods. Please read Results of Operations Cumulative Effect of Change in Accounting Principles beginning on page 31 for further discussion.

Non-GAAP Financial Measures. Management uses EBIT as one measure of financial performance of our business segments. EBIT is a non-GAAP financial measure and consists of operating income (loss), earnings (losses) from unconsolidated investments, other income and expense, net, minority interest income (expense), accumulated distributions associated with trust preferred securities, discontinued operations and cumulative effect of change in accounting principles. EBIT does not include interest expense or income taxes, each of which is evaluated on a consolidated level. Because we do not allocate interest expense and income taxes by segment, management believes that EBIT is a useful measure of our segment s operating performance for investors. EBIT should not be considered an alternative to, or more meaningful than, net income or cash flows from operations as determined in accordance with GAAP. Our segment and consolidated EBIT may not be comparable to similarly titled measures used by other companies.

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Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for 2003, 2002 and 2001, respectively (in millions). This financial data has been restated to reflect the items described in the Explanatory Note to the accompanying Consolidated Financial Statements. The restatements relate to an increased impairment associated with the sale of Illinois Power and our deferred income tax accounts. Please read this Explanatory Note for further discussion of these restatement items.

Year Ended December 31, 2003

	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(Restated)		
Operating income (loss)	$ 194	$ 170	$ (302)	$ (385)	$ (246)	$ (569)
Earnings (losses) from unconsolidated investments	128	(2)		(2)		124
Other items, net	4	(17)		31	2	20
Discontinued operations		(2)	(3)	(30)	7	(28)
Cumulative effect of change in accounting principles	24		(3)	43		64
Earnings (loss) before interest and taxes	$ 350	$ 149	$ (308)	$ (343)	$ (237)	$ (389)
Interest expense						(509)
Pre-tax loss						(898)
Income tax benefit						231
Net loss						$ (667)

Year Ended December 31, 2002

	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(Restated)		
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)
Discontinued operations		(37)	(561)	(51)	(854)	(1,503)
Cumulative effect of change in accounting principles					(234)	(234)
Earnings (loss) before interest and taxes	$ (432)	$ 20	$ (410)	$ (1,072)	$ (1,088)	$ (2,982)
Interest expense						(297)
Pre-tax loss						(3,279)
Income tax benefit						701
Net loss						$ (2,578)

Year Ended December 31, 2001						
	GEN	NGL	REG	CRM	Other and Eliminations	Total
				(Restated)		
Operating income	$ 391	$ 133	$ 182	$ 265	$	$ 971
Earnings (losses) from unconsolidated investments	202	13		(24)		191
Other items, net	(5)	(3)	2	(54)		(60)
Discontinued operations		(2)		(25)	(100)	(127)
Cumulative effect of change in accounting principles				3		3
Earnings (loss) before interest and taxes	$ 588	$ 141	$ 184	$ 165	$ (100)	$ 978
Interest expense						(255)
Pre-tax income						723
Income tax provision						(324)
Net income						$ 399

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The following table provides summary segmented operating statistics for 2003, 2002 and 2001, respectively:

	Year Ended December 31,		
	2003	**2002**	**2001**
Power Generation			
Million megawatt hours generated gross	39.1	39.8	40.3
Million megawatt hours generated net	37.2	37.4	34.5
Average natural gas price Henry Hub ($/MMbtu) (1)	$ 5.28	$ 3.35	$ 3.90
Average on-peak market power prices ($/MW hour)			
Cinergy	$ 37.26	$ 26.89	$ 34.85
Commonwealth Edison	36.73	26.45	34.15
Southern	41.27	30.10	38.30
New York Zone G	61.47	46.36	51.51
ERCOT	44.89	29.10	39.26
Natural Gas Liquids			
Natural gas processing volumes (MBbls/d):			
Field plants	59.6	56.0	56.1
Straddle plants	25.6	35.9	27.7
Total natural gas processing volumes	85.2	91.9	83.8
Fractionation volumes (MBbls/d)	185.3	215.2	226.2
Natural gas liquids sold (MBbls/d)	311.7	498.8	557.4
Average commodity prices:			
Crude oil WTI ($/Bbl)	$ 31.01	$ 25.75	$ 26.39
Natural gas Henry Hub ($/MMbtu) (2)	$ 5.38	$ 3.22	$ 4.26
Natural gas liquids ($/Gal)	$ 0.55	$ 0.40	$ 0.45
Fractionation spread ($/MMBtu) first of month	$ 0.87	$ 1.26	$ 0.88
Fractionation spread ($/MMBtu) daily	$ 0.79	$ 1.13	$ 1.15
Regulated Energy Delivery			
Electric sales in KWH (millions)			
Residential	5,309	5,548	5,202
Commercial	4,413	4,415	4,337
Industrial	6,123	6,306	6,353
Transportation of customer-owned electricity	2,382	2,505	2,645
Other	374	370	373
Total electric sales	18,601	19,144	18,910
Gas sales in Therms (millions)			
Residential	337	323	315
Commercial	145	137	136
Industrial	70	80	88
Transportation of customer-owned gas	226	233	246
Total gas delivered	778	773	785
Cooling degree days Actual (3)	980	1,467	1,302
Cooling degree days 10-year rolling average	1,214	1,246	1,297
Heating degree days Actual (4)	5,256	5,118	4,749

Heating degree days	10-year rolling average	4,930	5,002	5,032

(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.
(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.

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

	Year Ended December 31, 2003					
	GEN	NGL	REG	CRM	Other	Total
	(in millions)					
Goodwill impairment	$	$	$ (311)	$	$	$ (311)
Asset impairment			(193)			(193)
Southern Power tolling settlement				(133)		(133)
Sithe power tolling contract				(121)		(121)
Second quarter accrual of legal reserve					(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 fractionator 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	$ (510)	$ (303)	$ (33)	$ (858)

	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)

	Year Ended December 31, 2001					
	GEN	NGL	REG	CRM	Other	Total

			(in millions)			
Discontinued operations	$	$ (2)	$	$ (25)	$ (100)	$ (127)
Enron bankruptcy exposure				(129)		(129)
Illinois Power severance costs			(15)			(15)
Terminated Enron merger costs	(2)	(1)	(3)	(3)	(1)	(10)
Cumulative effect of change in accounting principle				3		3
Total	$ (2)	$ (3)	$ (18)	$ (154)	$ (101)	$ (278)

(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.

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Operating Income (Loss)

Operating income (loss) was $(569) million in 2003, compared to $(1,058) million and $971 million in 2002 and 2001, respectively.

GEN. Operating income (loss) for the GEN segment was $194 million in 2003, compared to $(341) million and $391 million in 2002 and 2001, respectively. Operating income for 2003 included general and administrative expense of $61 million and depreciation and amortization expense of $188 million. Please see Other beginning on page 28 for a consolidated discussion of general and administrative expense and depreciation and amortization expense.

Operating income for 2002 included the following charges:

- a $489 million impairment of goodwill (please see Note 10 Goodwill beginning on page F-38 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-27 for further discussion);
- $14 million associated with the impairment of a turbine; and
- $6 million associated with fees related to a voluntary action that we took that altered the accounting for certain lease obligations.

In addition, operating income for 2002 included general and administrative expense of $66 million and depreciation and amortization expense of $175 million. Operating income for 2001 included general and administrative expense of $103 million and depreciation and amortization expense of $163 million.

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 is 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 percent and 33 percent, 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 MW hours 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 income 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 facilities as part of the acquisition, which agreement expires in October 2004. Finally, 2003 operating income includes 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.

Operating income in 2002 included a $155 million decrease related to pricing and a $50 million benefit due to generated volumes versus 2001. GEN s results for 2002 reflect lower power prices on average as compared to 2001. This was primarily driven by a weakening economy, significantly compressed natural gas spark spreads and milder than normal summer and winter temperatures. Average on-peak prices in the Midwest and Northeast regions during 2002 decreased 23 percent and 10 percent, respectively, from the corresponding prices for 2001. Volumes increased in 2002 by 8 percent over 2001 primarily due to increased coal-fired production in the Midwest. The net MW hours generated by our Midwest and Northeast facilities were 18 million and 4.3 million, respectively, for 2001.

The decrease in operating income for 2002 also results from the fact that 2001 included approximately $50 million in revenue generating capacity contracts that expired and were not renewed in 2002. Also, revenues associated with the DNE facilities decreased approximately $40 million in 2002 as compared to 2001. This decrease primarily reflects reduced income recognized through the amortization of a liability established for a transitional power purchase agreement acquired from the seller of the facilities as part of the acquisition, which agreement expires in October 2004.

GEN s reported operating income for the 2003 period also includes approximately $4 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 the 2002 and 2001 periods include approximately $8 million and $11 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 the test, it was concluded that no impairment was necessary as the estimated undiscounted cash flows exceeded the book value of the respective asset.

Operating income for 2002 and 2001 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 and $133 million in 2002 and 2001, respectively. Operating income for 2003 included general and administrative expense of $37 million and depreciation and amortization expense of $81 million. Please see Other beginning on page 28 for a consolidated discussion of general and administrative expense and depreciation and amortization expense. 2003 operating income also included a $25 million gain associated with the sale of our Hackberry LNG project. Please see Note 3 Discontinued Operations, Dispositions, Contract Terminations and Acquisitions Dispositions and Contract Termination Hackberry LNG Project beginning on page F-25 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. Operating income for 2001 included general and administrative expense of $48 million and depreciation and amortization expense of $84 million.

The decrease in operating income in 2002 as compared to 2001 and 2003 relates primarily to the upstream business. As compared to 2002, 2001 and 2003 experienced higher natural gas and natural gas liquids prices, which resulted in a significant increase in processing plant margins at our field plants, where our frac spread risk is largely mitigated as a result of our substantial POP and POL contracts. In addition to favorable pricing, volumes of natural gas liquids produced at our field plants were 6% higher in 2003 as compared to 2002 and 2001. This is primarily due to increased production in the highly active drilling area in North Texas. Our 2003 straddle plant volumes were substantially in line with 2001 volumes, but much lower as compared to 2002 because of the low frac spread, 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.

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In our downstream business, volumes available for fractionation have steadily declined over each of the last three years from 226 MBbls per day in 2001 to 185 MBbls per day in 2003 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 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 and 2001 includes income of approximately $18 million and $14 million, respectively, 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 income (loss) for the REG segment was $(302) million in 2003, compared to $157 million and $182 million in 2002 and 2001, respectively. Operating income for 2003 included a $504 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-38, as well as general and administrative expense of $68 million and depreciation and amortization expense of $121 million. Please see Other beginning on page 28 for a consolidated discussion of general and administrative expense and depreciation and amortization expense.

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. Operating income for 2001 included a $15 million charge for severance costs, as well as general and administrative expense of $65 million and depreciation and amortization expense of $171 million.

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 May 1, 2002. 2002 operating income was favorably impacted as compared to 2001 due to weather-related increases in electric and gas residential and commercial sales volumes. The decrease in industrial revenues from 2001 to 2003 is primarily due to unfavorable economic conditions.

CRM. Operating income (loss) for the CRM segment was $(385) million in 2003, compared to $(951) million and $265 million in 2002 and 2001, respectively. 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 Sithe Independence power tolling arrangement;

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- $34 million charge associated with the cash settlement of the Batesville tolling arrangement; and
- $30 million 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. Please read Note 2 Accounting Policies Revenue Recognition beginning on page F-15 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-38);
- $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-27);
- $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.

Results for 2001 were impacted by the following:

- $129 million charge relating to exposure to Enron as a result of its Chapter 11 filing;
- $35 million mark-to-market gain on the Sithe Independence power tolling arrangement; and
- Higher commodity prices and price and basis volatility as well as market liquidity.

In addition, 2001 results included general and administrative expense of $205 million and depreciation and amortization expense of $34 million.

During 2002 and 2001, the 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 21 Segment Information beginning on page F-79 for further discussion.

Other. Other operating income (loss) was $(246) million in 2003, compared to zero in 2002 and 2001. The $(246) million 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.

Consolidated general and administrative expenses were $366 million in 2003, compared to $325 million and $420 million in 2002 and 2001, respectively. The $41 million increase from 2002 to 2003 is principally the result of the $50 million second quarter 2003 litigation reserve and higher professional fees, offset by significantly

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lower compensation costs in the 2003 period resulting from the work force reductions. The $95 million decrease from 2001 to 2002 is primarily due to lower compensation expenses in the 2002 period, due to the June 2002 and October 2002 work force reductions, which included 325 and 780 people, respectively, as well as a reduction in variable compensation expense.

Consolidated depreciation and amortization expenses were $454 million in 2003, compared to $466 million and $456 million in 2002 and 2001, respectively. The $12 million decrease from 2002 to 2003 is primarily due to reduced depreciation in our REG segment, offset by increased depreciation of generation assets due to an increased asset base. The $10 million increase from 2001 to 2002 is primarily due to the $23 million acceleration of regulatory amortization recorded in our REG segment in 2002, as well as a $17 million charge recorded in the fourth quarter 2002 associated with the acceleration of depreciation due to a change in the estimated useful lives of leasehold improvements and technology assets which were abandoned as part of our October 2002 restructuring. In addition, depreciation in 2002 was slightly higher due to an increased asset base. Increases in our asset base during the three-year period include the construction of the Heard and Riverside facilities in 2001, the construction of the Renaissance, Bluegrass and Foothills facilities in 2002 and the completion of Rolling Hills in 2003. These items were offset by a $46 million decrease due to the implementation of SFAS No. 142, which required the discontinuation of goodwill amortization beginning January 1, 2002.

Earnings (Losses) from Unconsolidated Investments.

Our earnings (losses) from unconsolidated investments were approximately $124 million during 2003 compared to $(80) million and $191 million in 2002 and 2001, respectively. Both 2002 and 2003 results include significant impairment charges related to these investments, primarily associated with the GEN segment.

GEN. GEN s earnings (losses) from unconsolidated investments were approximately $128 million during 2003 compared to $(71) million and $202 million in 2002 and 2001, respectively. Earnings for 2003 include a $26 million impairment of U.S. and international investments and 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 $144 million impairment of U.S. investments as well as a $50 million charge associated with our 50% share of a bad debt allowance recognized by West Coast Power. West Coast Power provided equity earnings of approximately $117 million, $17 million and $162 million in the years ended December 31, 2003, 2002 and 2001, respectively. Excluding impairments, earnings from our West Coast Power investment are the primary driver of results for each of the three periods.

Earnings at West Coast Power were higher in 2003 as compared to 2002 due to higher realized margins resulting from forward hedges put in place in connection with the execution of the CDWR contract. The decrease in earnings at West Coast Power from 2001 to 2002 is due in part to a reduction in contingent capacity and energy sales under the CDWR contract, as well as lower overall market prices. Please read Item 1. Business Segment Discussion Power Generation West region Western Electricity Coordinating Council (WECC) beginning on page 6 of our Original Filing for further discussion of the CDWR contract.

As noted above, 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.

As noted above, we recorded a $144 million impairment of U.S. investments in 2002, of which $33 million related to West Coast Power. 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 earnings (losses) from unconsolidated investments were approximately $(2) million during 2003 compared to $14 million and $13 million in 2002 and 2001, respectively. NGL s 2003 results were

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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 and $5 million to our results for the years ended December 31, 2002 and 2001, respectively.

CRM. CRM s earnings (losses) from unconsolidated investments were approximately $(2) million during 2003 compared to $(21) million and $(24) million in 2002 and 2001, respectively. As of December 31, 2003, CRM has no material unconsolidated investments. As such, 2004 and 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. The 2001 loss of $24 million is primarily comprised of a $19 million impairment on a technology investment and a $6 million loss on our investment in Nicor Energy.

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, $(107) million and $(60) million for 2003, 2002 and 2001, respectively.

The 2003 results included the following significant items:

- $17 million in interest income;
- $11 million gain on foreign currency transactions;
- $8 million charge for accumulated distributions associated with trust preferred securities; and
- The remaining amounts consist of individually insignificant items.

The 2002 results included the following significant 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

The remaining amounts consist of individually insignificant items.

The 2001 results included the following significant items:

$49 million interest income;

$13 million dividend income on our investment in Northern Natural preferred stock;

$93 million minority interest deduction, primarily related to Black Thunder;

$22 million charge for accumulated distributions associated with trust preferred securities; and

The remaining amounts consist of individually insignificant items.

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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.

The 2001 pre-tax loss of $127 million ($82 million after-tax) consists primarily of $100 million in pre-tax losses from the communications business and $31 million in pre-tax losses associated with the U.K. CRM 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.

On January 1, 2001, we adopted SFAS No. 133 and recognized a pre-tax benefit of $3 million ($2 million after-tax) in our CRM segment.

Please read Note 2 Accounting Policies beginning on page F-11 for further discussion of our adoption of recent accounting policies.

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Interest Expense

Interest expense totaled $509 million for 2003, compared with $297 million and $255 million for 2002 and 2001, respectively. The significant increase in 2003, as compared to 2002, primarily is 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.

The increase in interest expense in 2002 compared to 2001 was due primarily to increased principal borrowed to support our liquidity needs in 2002. Specifically, these additional principal amounts primarily relate to cash borrowings and letters of credit under our revolving credit facilities used to satisfy counterparty collateral demands. The effect of the increased interest expense relating to these additional principal amounts was partially offset by lower variable rates than in 2001.

Income Tax (Provision) 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 $352 million in 2002 and an income tax provision from continuing operations of $368 million in 2001. These amounts reflect effective rates of 26%, 23% and 43%, respectively. The 2003 and 2002 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 34% in 2003 and 37% in 2002, compared to the 2001 effective tax rate of 43%. 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 14 Income Taxes beginning on page F-50 for further discussion of our income taxes.

2004 Outlook

The following summarizes our 2004 outlook for our four reportable segments.

GEN Outlook. We expect that this segment s financial results will continue to reflect a sensitivity to power prices and that the 2004 pricing environment will be similar to what we experienced in 2003. We will continue our efforts to manage price risk through the optimization of fuel procurement and the marketing of power generated from our assets. Our sensitivity to prices and our ability to manage this sensitivity is subject to a

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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.

As discussed in Item 1. Business Segment Discussion Power Generation beginning on page 2 of our Original Filing, we enter into sales of capacity from our generation assets, which provide a revenue stream independent of energy sales. In late 2003 and continuing into 2004, we have seen increases in the market for capacity-related products from our peaking and intermediate generation facilities.

At the beginning of 2004, a substantial portion of our 2004 operating margin was under contract or hedged. The primary contracts included the CDWR contract held by West Coast Power and the Illinois Power power purchase agreement. Our future results of operations will be significantly impacted by our ability to extend or renew these agreements. West Coast Power, whose equity earnings are primarily derived from the CDWR contract, has been our largest contributor in terms of earnings from unconsolidated investments. The scheduled expiration of the CDWR contract in December 2004 will negatively impact the fair value of our investment in West Coast Power. As the value of the CDWR contract is realized through 2004, its fair value will decline, and, accordingly, we anticipate that the remaining value of the investment will be less than its book value. As a result, we will evaluate our investment quarterly and anticipate such reviews will necessitate an impairment of our investment of approximately $70 to $80 million in 2004. Please read Note 17 Commitments and Contingencies Summary of Material Legal Proceedings Western Long-Term Contract Complaints beginning on page F-61 for further discussion of the legal challenges to the CDWR contract.

Our power purchase agreement with Illinois Power is scheduled to expire at the end of 2004. In connection with the sale of Illinois Power to Ameren, DPM has agreed, conditioned on the closing of the sale, to enter into a two-year power purchase agreement with Ameren with volumes comparable to our current agreement. If we are unable to complete the sale of Illinois Power, any new agreement between Illinois Power and another Dynegy affiliate may not be executed at the same rates as our existing agreement. Please read REG Outlook below for further discussion of the power purchase agreement. Please also read Note 23 Subsequent Event beginning on page F-86 for further discussion of the pending sale of Illinois Power.

The current power purchase agreement between DMG and Illinois Power requires that notice of termination be presented by December 31, 2003, one year prior to the scheduled expiration. The parties have agreed to amend the agreement to extend this notice date requirement to March 31, 2004.

We continue to pursue additional sales of our ownership interests in a number of domestic and international generating projects that we consider non-strategic to this business. We recently executed purchase and sale agreements for our interests in Oyster Creek and Michigan Power and are continuing to pursue sales of our interests in Commonwealth, Black Mountain and Hartwell. We hold ownership interests of 50% or less in these projects, which aggregate less than 600 MWs of net generating capacity. These investments contributed approximately $26 million to our results in 2003. Please read Note 9 Unconsolidated Investments GEN Investments beginning on page F-35 for further discussion of these investments. Additionally, the pending transaction with Ameren includes the transfer of our 20% interest in the Joppa facility, which contributed approximately $2 million in earnings from unconsolidated investments in 2003. Our ability to consummate these sales on the terms and within the timeframes we anticipate is subject to several factors, many of which are beyond our control.

NGL Outlook. We expect that this segment s financial results will continue to reflect a sensitivity to natural gas and natural gas liquids prices and that the 2004 pricing environment will be similar to what we experienced in 2003. Our upstream volumes under POP and POL contracts will continue to benefit from these relatively higher prices. However, natural gas liquids production from both our own and third-party natural gas processing plants that are exposed to KW economics will continue to be exposed to depressed frac spreads, as natural gas

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continues to be higher in value than natural gas liquids on a Btu basis. As a result, we expect a reduced natural gas liquids supply to our fractionation, storage and distribution infrastructure, similar to 2003.

In some brief periods during 2003, the frac spread increased to a level sufficient to support natural gas liquids extraction, but not enough to generate meaningful upstream margin improvement. We expect this to occur during 2004. The increased natural gas liquids volumes produced during these brief periods resulted in some incremental margins in our downstream operations.

Drilling rig rates for natural gas throughout our core processing areas in New Mexico, West Texas, North Texas and offshore Louisiana continue to increase, consistent with natural gas prices that have averaged $5-$6/MMBtu. Continued exploration and production at these levels will benefit our upstream business by providing additional volumes for gathering and processing. If natural gas prices were to decline 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 for many of our commercial relationships. We expect similar collateral requirements until such time as our credit ratings improve substantially. Our ability to hedge future natural gas liquids production during 2004 will again be limited by reduced market liquidity, our obligation to post collateral and significant backwardation of natural gas liquids prices.

We intend to continue our aggressive North Texas gathering system expansion, where additional compression and plant debottlenecking are expected to add volumes to our expanded Chico gas processing plant. We expect to see volume growth in this area of 24% in 2004.

We also intend to continue to review our asset portfolio to maximize our return on investment. We have identified a few assets where our interests are not aligned with our partners. We may pursue sales of one or more of these 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 18 for further discussion.

REG Outlook. Future results of operations for the REG segment may be affected, either positively or negatively, by regulatory actions (with respect to rates or otherwise), general economic conditions, weather and customers choosing to utilize competitive alternate service providers. The effects of the REG segment on our consolidated results of operations will be significantly impacted by our ability to consummate the pending sale of Illinois Power to Ameren. Please read Note 23 Subsequent Event beginning on page F-86 for further discussion of this pending transaction.

We expect 2004 operating income, excluding depreciation, amortization, general and administrative expenses and the impairment of goodwill, to be similar to actual results for 2003. Cash flow from operations is expected to be higher in 2004 than in 2003 as a result of the delayed recovery of gas inventories in 2003 and higher prepaid gas costs from our customers in 2003 as compared to our 2004 expectations.

Illinois Power s ability to meet its capacity and energy needs beyond 2004 is addressed in connection with the pending sale of Illinois Power to Ameren. Pursuant to a related agreement, which is conditioned upon the closing of the transaction, Illinois Power will purchase 2,800 MWs of capacity and up to 11.5 million MWh of energy from DPM at fixed prices for two years beginning in January 2005. Additionally, DPM will sell 300 MWs of capacity in 2005 and 150 MWs of capacity in 2006 to Illinois Power at a fixed price with an option to purchase energy at market-based prices. Any capacity and energy needs not met by this agreement would be secured from either existing agreements, through a specified competitive purchasing process, or, in limited circumstances, through open market purchases.

The current power purchase agreement between DMG and Illinois Power requires that notice of termination be presented by December 31, 2003, one year prior to the scheduled expiration. The parties have agreed to amend the agreement to extend this notice date requirement to March 31, 2004.

In the event that both the pending transaction for the sale of Illinois Power to Ameren is not completed, the existing agreement with DMG is terminated and no replacement agreement is executed with a Dynegy affiliate, Illinois Power will be required to purchase a substantial portion of its power on the open market at then current market prices. In the event that the Ameren transaction is not completed and the existing agreement with DMG is either not terminated or is replaced by another agreement with a Dynegy affiliate, Illinois Power will be required to purchase any amount of capacity and energy not provided under the contract on the open market at then current market prices. Volatility in market prices for power could affect Illinois Power to the extent that it would be required to purchase power in the open market.

CRM Outlook. Our CRM business future results of operations will be significantly impacted by our ability to execute our exit strategy. We continue to explore opportunities to assign or renegotiate the terms of some of our four remaining power tolling arrangements. If we do not renegotiate or terminate these power tolling arrangements, these arrangements will continue to negatively impact our earnings and cash flows based on the current pricing environment. Even if we do renegotiate or terminate some of these arrangements, we could be required to pay a significant amount of cash relating to any such renegotiation or termination which may also negatively impact earnings and cash flows. For a discussion of our annual and long-term obligations under these arrangements, see Item 1. Business Segment Discussion Customer Risk Management beginning on page 18 of our Original Filing.

The earnings of the CRM segment may also be significantly impacted, either positively or negatively, by mark-to-market changes in the value of a derivative contract associated with the Sithe Independence tolling agreement as power and gas prices change.

We have posted approximately $120 million of collateral associated with this business. Approximately $20 million of this balance relates to our tolling arrangements. An additional $40 million relates to the ABG Gas Supply gas contract, which will expire in the first quarter of 2006. The remaining $60 million is related to our legacy gas and power positions, which collateral will be substantially eliminated by 2007.

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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:

	For the Year Ended December 31, 2003					
	GEN	NGL	REG	CRM	Other & Eliminations	Consolidated
	(in millions)					
Operating Cash Flows Before Changes in Working Capital	$ 457	$ 233	$ 198	$ (29)	$ (420)	$ 439
Changes in Working Capital	(29)	(47)	(131)	525	119	437
Net Cash Provided by (Used in) Operating Activities	$ 428	$ 186	$ 67	$ 496	$ (301)	$ 876

	For the Year Ended December 31, 2002					
	GEN	NGL	REG	CRM	Other & Eliminations	Consolidated
	(in millions)					
Operating Cash Flows Before Changes in Working Capital	$ 349	$ 73	$ 371	$ 200	$ (124)	$ 869
Changes in Working Capital	(91)	(49)	(109)	(518)	(127)	(894)
Net Cash Provided by (Used in) Operating Activities	$ 258	$ 24	$ 262	$ (318)	$ (251)	$ (25)

	For the Year Ended December 31, 2001					
	GEN	NGL	REG	CRM	Other & Eliminations	Consolidated
	(in millions)					
Operating Cash Flows Before Changes in Working Capital	$ 431	$ 147	$ 269	$ 180	$ 43	$ 1,070
Changes in Working Capital	71	12	(160)	(476)	33	(520)
Net Cash Provided by (Used in) Operating Activities	$ 502	$ 159	$ 109	$ (296)	$ 76	$ 550

Operating Cash Flow. Our cash flow provided by operations totaled $876 million for the 12 months ended December 31, 2003. 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 the 12 months ended December 31, 2003.

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For the 12 months ended December 31, 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.

For the 12 months ended December 31, 2001, our cash flow provided by operations totaled $550 million. Our GEN segment experienced strong operational results, reflecting added generation capacity and a favorable commodity price environment, which contributed operating cash flows of approximately $500 million. Similarly, our NGL segment experienced strong operational results stemming from beneficial price realization and positive working capital changes related to sales of natural gas liquids in storage due to the favorable business environment.

Capital Expenditures and Investing Activities. Cash used in investing activities for the 12 months ended December 31, 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 the 12 months ended December 31, 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.

Finally, cash used in investing activities in 2001 totaled $3.8 billion. Included in 2001 capital expenditures is the purchase of the Central Hudson power generation facilities for $903 million. Additional capital expenditures of approximately $1.7 billion principally related to the construction of power generation assets, improvements of existing facilities related to the REG segment and investments associated with technology infrastructure. Also during 2001, we invested $1.5 billion on our purchase of Northern Natural Series A Preferred Stock. Business acquisitions during 2001 included approximately $595 million related to the purchase of BGSL and approximately $40 million related to our purchase of iaxis. Proceeds from asset sales in 2001 included the sale of the Central Hudson facilities in May 2001 for $920 million pursuant to a leveraged lease transaction, in addition to proceeds from the disposal of non-strategic Canadian assets and investments. Other investing activities in 2001 primarily include investments relating to a generation and a telecommunications lease arrangement.

Financing Activities. 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.

- 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 notes offering; (2) $1,607 million associated with the August 2003 refinancing, (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 2, 2003 credit facility restructuring.

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In connection with the August 2003 refinancing, we made a $225 million cash payment to ChevronTexaco.

Repayments of long-term debt totaled $2.7 billion for 2003 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 public notes; (3) $360 million prepayment of the Term B loan outstanding under DHI s restructured credit facility; (4) $200 million prepayment of the Term A loan outstanding under DHI s 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 Generation 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 credit agreement; (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 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 credit agreement;

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 credit agreement;

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 therefrom;

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 include $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;

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.

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During 2001, cash provided by financing activities totaled approximately $3.5 billion. The following summarizes the significant items:

Proceeds from long-term borrowings consisted primarily of (1) the issuance of $496 million of 6.875% Senior Notes due April 1, 2011, net of issuance costs. Such proceeds were used to repay credit facility borrowings obtained to finance the purchase of the Central Hudson generation facilities; (2) $282 million associated with the ABG Gas Supply credit agreement; (3) the issuance of $187 million of variable rate pollution control bonds by Illinois Power; and (4) proceeds from lease arrangements of approximately $340 million, which were used in the construction of two generation facilities and the U.S. fiber optic network;

Repayments of long-term debt include $187 million of variable rate pollution control bonds, which were repaid and retired contemporaneously with the issuance of lower rate bonds discussed above, $87 million of transitional funding trust notes and $30 million of Illinova s medium term notes;

Proceeds from the sale of capital stock and from options and 401(k) plans approximated $604 million. We sold approximately 29.8 million shares of common stock during 2001. The offerings included approximately 27.5 million shares of Class A common stock sold to the public in December 2001. We also sold approximately 1.2 million shares of Class B common stock to ChevronTexaco in private transactions pursuant to the exercise of ChevronTexaco s preemptive rights. This amount is net of underwriting commissions and expenses of approximately $32 million;

Proceeds of $1.5 billion relate to the sale of 150,000 shares of Series B Preferred Stock to ChevronTexaco, concurrent with Dynegy s purchase of Northern Natural Series A Preferred Stock;

We repurchased approximately 1.7 million shares of our outstanding Class A common stock pursuant to our stock repurchase plan at a cost of $68 million;

Illinois Power redeemed $100 million of Trust Originated Preferred Securities issued by Illinois Power Financing I. The redemption was financed with $85 million from cash on hand and $15 million in commercial paper; and

We made payments of dividends and other distributions totaling $98 million.

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, while the regulated energy delivery business has higher seasonal gas sales in the winter and higher seasonal electricity sales in the summer. These trends 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.

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CRITICAL ACCOUNTING POLICIES

Our Controller s 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 regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We have identified the following six critical accounting policies that require a significant amount of judgment and are considered to be the most 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;
- 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, 2003, 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 businesses consist largely of the ownership and operation of physical assets that we use in various generation, processing and delivery operations. These processes include 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 transmission lines. End sales from these businesses result in physical delivery of commodities to our wholesale, commercial and 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 forward physical and financial transactions, 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

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computed by multiplying all existing positions in the portfolio by estimated prices, reduced by a LIBOR-based 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 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.

Under SFAS No. 133, as amended, 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, 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 a long-lived asset is held and used, the determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the fair value of the assets and recording a loss if the 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 to determine if an impairment loss is required.

We follow the guidance of APB 18, The Equity Method of Accounting for Investments in Common Stock, and SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities, 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 events warrant an assessment. Fair value utilized in this assessment is also based on our estimate of future cash flows.

Our assessment regarding the existence of impairment factors is based on market conditions, operational performance and legal factors impacting our businesses. Our review of factors present and the resulting estimation of the appropriate carrying value of our property, plant and equipment, investments and goodwill are subject to judgments and estimates that management is required to make. Our fair value estimates are impacted significantly by the estimated useful lives of the assets, commodity prices, regulations and discount rate assumptions. If different judgments were applied to fair value calculations, the fair value estimate, and potential resulting impairment, could differ from our estimate. Actual results could vary materially from these estimates.

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Estimated Useful Lives

The estimated useful lives of our long-lived assets are used to compute depreciation expense and are also used for impairment testing. Estimated useful lives are based 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. These estimates could be impacted by future energy prices, environmental regulations and competition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation charges would be accelerated.

Accounting for Contingencies

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, 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 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 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 judgments were applied with respect to these matters, it is likely that reserves would be recorded for different amounts.

Liabilities are recorded when environmental assessment indicates that remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based on relevant past experience, currently enacted laws and regulations, existing technology, site-specific costs and cost-sharing arrangements. Recognition of any joint and several liability is based upon our best estimate of our final pro-rata share of such liability. Any changes in assumptions could lead to increases or decreases in our ultimate liability, with any such changes recognized immediately in earnings.

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 is recognized immediately in earnings.

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. Please read Note 14 Income Taxes beginning on page F-50 for further discussion.

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 exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences 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

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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. To the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or benefit within the tax provisions in the consolidated statements of operations. Significant management judgment is required in determining any valuation allowance recorded against our deferred tax assets.

We have recorded deferred tax assets principally resulting from net operating losses, AMT credits and capital losses. As of December 31, 2003 and 2002, deferred tax assets related to net operating losses totaled $543 million and $246 million, respectively. As of December 31, 2003 and 2002, deferred tax assets related to AMT credits totaled $218 million. We have not established a valuation allowance against these net operating losses or AMT credits, as we believe that it is more likely than not that these deferred tax assets will be realized. We expect that future sources of taxable income, including the sale of Illinois Power, reversing temporary differences and other tax planning strategies will be sufficient to realize these assets. 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.

As of December 31, 2003 and 2002, deferred tax assets related to capital losses totaled $194 million and $223 million, respectively, and valuation allowances recorded related to these losses totaled $135 million and $171 million, respectively. In 2003, we reduced the valuation allowance by $33 million based on capital gains recognized in 2003 or anticipated to be recognized in early 2004 related to various dispositions, excluding our sale of our interest in Joppa, which is subject to regulatory approval. Any changes 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 14 Income Taxes beginning on page F-50 for a discussion of the change in our valuation allowance.

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 2003. Accordingly, at December 31, 2003, we used a discount rate of 6.0%, a decline of 50 basis points from the 6.5% rate used as of December 31, 2002. This decline in the discount rate had the impact of increasing the underfunded status of our pension plans by approximately $44 million.

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, 2004 is 8.75%, compared with 9.00% during 2003. This change did not impact 2003 pension expense, but it will adversely impact pension expense beginning in 2004. We expect the decrease in this assumption, coupled with the decreased discount rate discussed above and the passage of time, will increase 2004 pension expense by approximately $15 million over 2003 expense.

On December 31, 2003, 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. As a result, in accordance with SFAS No. 87, Employers Accounting for Pensions, as of December 31, 2003, we have recognized a charge to accumulated other comprehensive loss of $57 million (net of taxes of $33 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.

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, 2004	Impact on 2004 Expense
	(in millions)	
Increase Discount Rate 50 basis points	$ (58.5)	$ (5.3)
Decrease Discount Rate 50 basis points	64.6	5.7
Increase Expected Rate of Return 50 basis points		(3.2)
Decrease Expected Rate of Return 50 basis points		3.2

We expect to make $8 million in cash contribution related to our pension plans during 2004. In addition, it is likely that we will be required to continue to make contributions to the pension plan beyond 2004. 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 $57 million in 2005 and $46 million in 2006.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 2 Accounting Policies Accounting Principles Adopted beginning on page F-19 for a discussion of recently issued accounting pronouncements affecting us. Specifically, 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. We also adopted SFAS No. 143 effective January 1, 2003. We adopted SFAS No. 150 and EITF Issue 03-11 effective July 1, 2003. We adopted portions of FIN 46R, as required by GAAP, effective December 31, 2003.

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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, 2003 (in millions)
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at January 1, 2003	$ 363
Risk-management losses recognized through the income statement in the period, net (1)	(184)
Cash received related to risk-management contracts settled in the period, net (2)	(260)
Changes in fair value as a result of a change in valuation technique (3)	
Non-cash adjustments and other (4)	(56)
Fair value of portfolio at December 31, 2003	$ (137)
Income Statement Reconciliation	
Risk-management losses recognized through the income statement in the period, net (1)	$ (184)
Physical business recognized through the income statement in the period, net (5)	(130)
Non-cash adjustments and other	5
Net recognized operating loss	$ (309)
Cash Flow Statement	
Cash received related to risk-management contracts settled in the period, net (2)	$ 260
Estimated cash paid related to physical business settled in the period, net (5)	(130)
Timing and other, net (6)	(57)
Cash received during the period	$ 73
Risk-Management cash flow adjustment for the year ended December 31, 2003 (7)	$ 382

(1) This amount consists primarily of $121 million in mark-to-market losses on contracts associated with the Sithe Independence power tolling arrangement and a $30 million loss associated with the settlement of power supply agreements with Kroger.
(2) This amount consists primarily of the Kroger settlement of approximately $110 million and cash received due to the wind-down of our CRM business.
(3) Our modeling methodology has been consistently applied.
(4) This amount primarily consists of approximately $97 million of risk-management assets that were removed from the risk-management accounts at January 1, 2003 in conjunction with the adoption of certain provisions of EITF Issue 02-03. This amount is offset primarily by changes in value associated with cash flow hedges.
(5) This amount consists primarily of capacity payments on our power tolling arrangements.
(6) This amount consists primarily of cash paid in connection with the settlement of cash flow hedges.
(7) This amount is calculated as Cash received during the period less Net recognized operating loss.

The net risk management liability of $137 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, 2003. 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	2004	2005	2006	2007	2008	Thereafter
				(in millions)			
Mark-to-Market (1)	$ (144)	$ (22)	$ (17)	$ (25)	$ (39)	$ (12)	$ (29)
Cash Flow (2)	(152)	(17)	(14)	(24)	(43)	(15)	(39)

(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, 2003 of $137 million on the consolidated balance sheets includes the $144 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, 2003, based on our valuation methodology.

Net Fair Value of Risk-Management Portfolio

	Total	2004	2005	2006	2007	2008	Thereafter
				(in millions)			
Market Quotations (1)	$ (69)	$ (22)	$ (20)	$	$ (25)	$ (1)	$ (1)
Prices Based on Models (2)	(75)		3	(25)	(14)	(11)	(28)
Total	$ (144)	$ (22)	$ (17)	$ (25)	$ (39)	$ (12)	$ (29)

(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 40.

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 80 of our Original Filing.

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UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

This Form 10-K/A 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, e other words of similar meaning. In particular, these include, but are not limited to, statements relating to the following:

- projected operating or financial results, include anticipated cash flows from operations and asset sale proceeds for 2004;
- expectations regarding capital expenditures, interest expense and other payments;
- our ability to execute 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 as they come due, particularly the February 2005 maturity of our $1.1 billion revolving credit facility;
- 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 consummate the disposition of specified non-strategic assets on the terms and in the timeframes anticipated, particularly the agreed upon sale of Illinois Power to Ameren; 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, particularly for power, natural gas, natural gas liquids and other fuels, as such as the frac spread and, to a lesser extent, the natural gas spark spread;
- the effects of competition in our asset-based business lines;

the effects of the proposed sale of specified non-strategic assets, particularly the agreed upon sale of Illinois Power to Ameren;

the condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions, and our financial condition, including our ability to satisfy our significant debt maturities;

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

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

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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 and regulated energy delivery 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 the other effects of our 2003 restructuring and refinancing transactions, including the security arrangements and restrictive covenants contained in the related financing agreements;

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 the CRM business and environmental liabilities that may not be covered by indemnity or insurance, as well as the FERC, U.S. Attorney and other similar investigations primarily surrounding Project Alpha and our past trading practices;

other North American regulatory or legislative developments that affect the regulation of the electric utility industry, the demand and pricing for energy generally, increase in 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/A. 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/A 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/A, except as otherwise required by applicable law.

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

Our financial statements and financial statement schedules are set forth at pages F-1 through F-94 inclusive, found at the end of this annual report, and are incorporated herein by reference.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures. Effective 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 our establishment of a disclosure committee and the various processes carried out under the direction of this committee in an effort to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified by the SEC. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective at the reasonable assurance level and designed to ensure that the information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the requisite time periods. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal controls over financial reporting (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) identified in connection with the evaluation of our internal controls performed during the fourth quarter 2003 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

During the second and third quarter 2004 we identified deficiencies in our internal controls 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. We also identified deficiencies in our tax accounting and tax reconciliation controls and processes that make this an area of particular focus. During the third quarter 2004, we determined that adjustments related to our deferred income tax accounts in periods prior to 2004 were required. We identified these deficiencies and promptly brought them to the attention of our audit and compliance committee and independent auditors. Accordingly, in this Form 10-K/A, we have restated our consolidated financial statements. For further information, please see the Explanatory Note beginning on page F-8. We believe we have addressed these tax deficiencies, by taking the following steps to improve our internal controls around our tax accounting and tax reconciliation controls and processes:

- Increased the levels of review in the preparation of the quarterly and annual tax provision;
- Formalized processes, procedures and documentation standards; and
- Restructured our Tax Department to ensure segregation of duties regarding preparation and review of the quarterly and annual tax provision.

Beginning with the year ending December 31, 2004, Section 404 of the Sarbanes-Oxley Act of 2002 requires us to provide an annual internal controls report of management. This report must contain (i) a statement of management s responsibility for establishing and maintaining adequate internal controls over financial reporting for our company, (ii) a statement identifying the framework used by management to conduct the required evaluation of the effectiveness of our internal controls over financial reporting, (iii) management s assessment of the effectiveness of our internal controls over financial reporting as of the end of our most recent fiscal year, including a statement as to whether or not our internal controls over financial reporting are effective, and (iv) a statement that our independent auditors have issued an attestation report on management s assessment of our internal controls over financial reporting. Additionally, Section 404 requires that our independent auditors

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attest to and report on management s assessment of our internal controls over financial reporting. In seeking to achieve compliance with Section 404 within the prescribed period, management formed a steering committee to oversee our efforts to comply with Section 404, engaged outside consultants and adopted and implemented a detailed project work plan to assess the adequacy of our internal controls over financial reporting, remediate any control weaknesses that may be identified, validate through testing that controls are functioning as documented and implement a continuous reporting and improvement process for internal controls over financial reporting.

Additionally, the Public Company Accounting Oversight Board recently adopted very stringent standards governing management s required evaluation of its internal controls over financial reporting and the independent auditors review of those controls and management s evaluation thereof. These standards will likely result in a significant number of companies, which may include Dynegy, identifying significant deficiencies and/or material weaknesses in their internal controls. Indeed, the items referenced in the preceding paragraphs could preclude our independent auditors from delivering an unqualified opinion on internal controls under Section 404 of Sarbanes-Oxley.

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PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

(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
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.
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).
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).

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Exhibit Number	Description
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).
4.15	Exchange and Registration Rights Agreement (Notes) dated August 11, 2003 between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.3 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 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).
4.17	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).

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Exhibit Number	Description
4.18	Indenture dated August 11, 2003 between Dynegy Inc. and Wilmington Trust Company, as trustee (incorporated by reference to Exhibit 4.6 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	Junior Unsecured Subordinated Note due 2016 in the principal amount of $225,000,000 issued on August 11, 2003 by Dynegy Inc. to Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.7 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	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).
4.21	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).
4.22	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).
4.23	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).
4.24	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).
	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).
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).

Exhibit Number	Description
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. 1-11156).
10.10	Employment Agreement, effective February 1, 2000, between Charles L. Watson and Dynegy Inc. (incorporated by reference to Exhibit 10.9 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156)
10.11	Employment Agreement, effective February 1, 2000, between Stephen W. Bergstrom and Dynegy Inc. (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1999 of Dynegy Inc., File No. 1-11156).
10.12	Employment Agreement, effective as of September 16, 2002, between R. Blake Young and Dynegy Inc. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2002 of Dynegy Inc., File No. 1-15659).
10.13	Employment Agreement, effective February 1, 2000, between Alec G. Dreyer 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, 2002 of Dynegy Inc., File No. 1-11156).
10.14	Employment Agreement, effective December 2, 2002, between Nick J. Caruso and Dynegy Inc. (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2002 of Dynegy Inc., File No. 1-11156).
***10.15	Employment Agreement, effective March 11, 2003, between Carol F. Graebner and Dynegy Inc.
10.16	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).
10.17	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).
***10.18	Amendment to the Dynegy Inc. 401(K) Savings Plan, effective January 1, 2004.
***10.19	First Amendment to Dynegy Inc. 401(K) Savings Plan, effective February 11, 2002.
***10.20	Second Amendment to Dynegy Inc. 401(K) Savings Plan, effective January 1, 2002.
***10.21	Third Amendment to Dynegy Inc. 401(K) Savings Plan, effective October 1, 2003.
10.22	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).
10.23	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).
10.24	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).
10.25	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).

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Exhibit Number	Description
10.26	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).
10.27	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).
***10.28	Second Supplement to the Dynegy Inc. Executive Severance Pay Plan.
***10.29	Dynegy Inc. Mid-Term Incentive Performance Award Program.
10.30	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).
***10.31	Amendment to the Dynegy Northeast Generation, Inc. Savings Incentive Plan, effective January 1, 2004.
10.32	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).
10.33	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).
10.34	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).
*10.35	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).
10.36	Dynegy Inc. Severance Pay Plan (incorporated by reference to Exhibit 10.41 to the Annual Report on Form 10-K for the Fiscal Year Ended December 31, 1998 of Dynegy Inc., File No. 1-11156).
10.37	Credit Agreement, dated as of April 1, 2003, among Dynegy Holdings Inc., as borrower, Dynegy Inc., as parent guarantor, various subsidiary guarantors and the lenders party thereto (incorporated by reference to Exhibit 10.31 to the Annual Report on Form 10-K for the Year Ended December 31, 2002 of Dynegy Inc., File No. 1-15659).
10.38	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).
10.39	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).
10.40	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).

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Exhibit Number	Description
10.41	Third Amendment to the Loan Documents dated as of July 15, 2003 among Dynegy Holdings Inc., as borrower, Dynegy Inc., as parent guarantor, various subsidiary guarantors and the lenders party thereto, including the Lender Consent dated August 1, 2003 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the Quarterly Period Ended June 30, 2003 of Dynegy Inc., File No. 1-15659).
10.42	Fourth Amendment to the Credit Agreement dated as of October 9, 2003 among Dynegy Holdings Inc., as borrower, Dynegy Inc., as parent guarantor, various subsidiary guarantors and the lenders party thereto (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K of Dynegy Inc. filed on October 15, 2003, File No. 1-15659).
10.43	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).
10.44	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).
10.45	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).
10.46	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).
10.47	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).
10.48	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).
10.49	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).
10.50	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).
10.51	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).
***14.1	Dynegy Inc. Code of Ethics for Senior Financial Professionals.
***21.1	Subsidiaries of the Registrant.

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Exhibit Number	Description
**23.1	Consent of PricewaterhouseCoopers LLP.
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* 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
*** Previously filed
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.

(b) Reports on Form 8-K of Dynegy Inc. for the fourth quarter of 2003.

1. During the quarter ended December 31, 2003, we filed a Current Report on Form 8-K on October 2, 2003. Items 5 and 7 were reported and no financial statements were filed.

2. During the quarter ended December 31, 2003, we filed a Current Report on Form 8-K on October 15, 2003. Items 5 and 7 were reported and no financial statements were filed.

3. During the quarter ended December 31, 2003, we filed a Current Report on Form 8-K on October 30, 2003. Items 7 and 12 were reported and no financial statements were filed.

4. During the quarter ended December 31, 2003, we filed a Current Report on Form 8-K on November 4, 2003. Items 5 and 7 were reported and no financial statements were filed.

5. During the quarter ended December 31, 2003, we filed a Current Report on Form 8-K on November 18, 2003. Items 5 and 7 were reported and no financial statements were filed.

6. During the quarter ended December 31, 2003, we filed a Current Report on Form 8-K on November 24, 2003. Items 5 and 7 were reported and no final statements were filed.

7. During the quarter ended December 31, 2003, we filed a Current Report on Form 8-K on December 8, 2003. Items 5 and 7 were reported and no final statements were filed.

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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: January 18, 2005	By:	/s/ Nick J. Caruso
		Nick J. Caruso
		Executive Vice President and Chief Financial Officer

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DYNEGY INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Dynegy Inc.:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Dynegy Inc. and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company s management; our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States), which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 17, the Company is the subject of substantial litigation. The Company s ongoing liquidity, financial position and operating results may be adversely impacted by the nature, timing and amount of the resolution of such litigation. The consolidated financial statements do not include any adjustments, beyond existing accruals applicable under Statement of Financial Accounting Standards No. 5, Accounting for Contingencies, that might result from the ultimate resolution of such matters.

As discussed in the Explanatory Note beginning on page F-8, the consolidated financial statements have been restated to reflect an increase in the impairment associated with the sale of Illinois Power and for adjustments to the deferred income tax accounts.

As discussed in Note 2, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2003. As discussed in Note 2, the Company adopted the provisions of Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, as of July 1, 2003. As discussed in Note 2, the Company adopted certain provisions of Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities an interpretation of ARB 51 (revised December 2003), as of December 31, 2003. As discussed in Note 2, the Company adopted the provisions of Statement of Financial Accounting Standards No. 132 (revised 2003), Employers Disclosures About Pensions and Other Postretirement Benefits an Amendment of FASB Statements No. 87, 88, and 106 and a revision of FASB Statement No. 132, as of December 31, 2003. As discussed in Note 2, the Company adopted the provisions of Emerging Issues Task Force No. 02-03, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, related to the rescission of Emerging Issues Task Force Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, as of January 1, 2003. As discussed in Note 2, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets, and Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, as of January 1, 2002.

PricewaterhouseCoopers LLP

Houston, Texas

February 26, 2004, except for the Explanatory Note beginning on page F-8, as to which the date is January 18, 2005.

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DYNEGY INC.

CONSOLIDATED BALANCE SHEETS

(RESTATED)

See Explanatory Note

(in millions, except share data)

	December 31, 2003	December 31, 2002
ASSETS		
Current Assets		
Cash and cash equivalents	$ 477	$ 757
Restricted cash	19	17
Accounts receivable, net of allowance for doubtful accounts of $184 and $151, respectively	1,010	2,791
Accounts receivable, affiliates	25	31
Inventory	279	236
Assets from risk-management activities	818	2,618
Prepayments and other current assets	402	1,136
Total Current Assets	3,030	7,586
Property, Plant and Equipment	9,867	9,659
Accumulated depreciation	(1,664)	(1,201)
Property, Plant and Equipment, Net	8,203	8,458
Other Assets		
Unconsolidated investments	612	668
Assets from risk-management activities	629	2,529
Goodwill	15	326
Other long-term assets	472	462
Total Assets	12,961	20,029
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 522	$ 1,586
Accounts payable, affiliates	74	65
Accrued liabilities and other current liabilities	811	1,818
Liabilities from risk-management activities	838	2,418
Notes payable and current portion of long-term debt	245	861
Current portion of long-term debt to affiliates	86	
Total Current Liabilities	2,576	6,748
Long-term debt	5,124	5,454
Long-term debt to affiliates	769	

Total Long-term Debt	5,893	5,454
Other Liabilities		
Liabilities from risk-management activities	746	2,366
Deferred income taxes	524	765
Other long-term liabilities	743	924
Total Liabilities	10,482	16,257
Minority Interest	121	146
Commitments and Contingencies (Note 17)		
Redeemable Preferred Securities, redemption value of $411 and $1,711 at December 31, 2003 and December 31, 2002, respectively (Note 15)	411	1,423
Stockholders Equity		
Class A Common Stock, no par value, 900,000,000 shares authorized at December 31, 2003 and December 31, 2002; 280,350,169 and 274,850,589 shares issued and outstanding at December 31, 2003 and December 31, 2002, respectively	2,848	2,825
Class B Common Stock, no par value, 360,000,000 shares authorized at December 31, 2003 and December 31, 2002; 96,891,014 shares issued and outstanding at December 31, 2003 and December 31, 2002	1,006	1,006
Additional paid-in capital	41	705
Subscriptions receivable	(8)	(12)
Accumulated other comprehensive loss, net of tax	(20)	(55)
Accumulated deficit	(1,852)	(2,198)
Treasury stock, at cost, 1,679,183 shares at December 31, 2003 and December 31, 2002	(68)	(68)
Total Stockholders Equity	1,947	2,203
Total Liabilities and Stockholders Equity	$ 12,961	$ 20,029

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(RESTATED)

See Explanatory Note

(in millions, except per share data)

	Year Ended December 31,		
	2003	**2002**	**2001**
Revenues	$ 5,787	$ 5,326	$ 9,124
Cost of sales, exclusive of depreciation shown separately below	(5,054)	(4,596)	(7,317)
Depreciation and amortization expense	(454)	(466)	(452)
Goodwill impairment	(311)	(814)	
Impairment and other charges	(200)	(190)	
Gain on sale of assets	29	7	36
General and administrative expenses	(366)	(325)	(420)
Operating income (loss)	(569)	(1,058)	971
Earnings (losses) from unconsolidated investments	124	(80)	191
Interest expense	(509)	(297)	(255)
Other income and expense, net	25	(59)	55
Minority interest income (expense)	3	(36)	(93)
Accumulated distributions associated with trust preferred securities	(8)	(12)	(22)
Income (loss) from continuing operations before income taxes	(934)	(1,542)	847
Income tax benefit (expense)	246	352	(368)
Income (loss) from continuing operations	(688)	(1,190)	479
Loss on discontinued operations, net of taxes (Note 3)	(19)	(1,154)	(82)
Income (loss) before cumulative effect of change in accounting principles	(707)	(2,344)	397
Cumulative effect of change in accounting principles, net of taxes (Note 2)	40	(234)	2
Net income (loss)	(667)	(2,578)	399
Less: preferred stock dividends (gain) (Note 15)	(1,013)	330	42
Net income (loss) applicable to common stockholders	$ 346	$ (2,908)	$ 357
Earnings (Loss) Per Share (Note 16):			
Basic earnings (loss) per share:			
Earnings (loss) from continuing operations	$ 0.87	$ (4.16)	$ 1.35
Loss from discontinued operations	(0.05)	(3.15)	(0.26)
Cumulative effect of change in accounting principles	0.11	(0.64)	0.01

Basic earnings (loss) per share	$ 0.93	$ (7.95)	$ 1.10
Diluted earnings (loss) per share:			
Earnings (loss) from continuing operations	$ 0.79	$ (4.16)	$ 1.29
Loss from discontinued operations	(0.04)	(3.15)	(0.25)
Cumulative effect of change in accounting principles	0.09	(0.64)	0.01
Diluted earnings (loss) per share	$ 0.84	$ (7.95)	$ 1.05
Basic shares outstanding	374	366	326
Diluted shares outstanding	423	370	340

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(RESTATED)

See Explanatory Note

(in millions)

	Year Ended December 31,		
	2003	**2002**	**2001**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (667)	$ (2,578)	$ 399
Adjustments to reconcile net income (loss) to net cash flows from operating activities:			
Depreciation and amortization	525	613	482
Goodwill impairment	311	814	
Impairment and other charges	200	847	
(Earnings) losses from unconsolidated investments, net of cash distributions	33	232	(117)
Risk-management activities	382	638	(17)
Loss (gain) on sale of assets	(57)	620	(36)
Deferred income taxes	(258)	(706)	253
Cumulative effect of change in accounting principles (Note 2)	(40)	234	(2)
Reserve for doubtful accounts	19	68	55
Other	(9)	87	53
Changes in working capital:			
Accounts receivable	1,683	421	1,622
Inventory	93	3	24
Prepayments and other assets	726	(762)	(183)
Accounts payable and accrued liabilities	(2,017)	(454)	(2,011)
Changes in non-current assets and liabilities, net	(48)	(102)	28
Net cash provided by (used in) operating activities	876	(25)	550
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(333)	(947)	(2,551)
Investments in unconsolidated affiliates	(5)	(14)	(1,533)
Business acquisitions, net of cash acquired		(20)	(603)
Proceeds from asset sales, net	72	1,583	1,078
Other investing, net		75	(219)
Net cash provided by (used in) investing activities	(266)	677	(3,828)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from long-term borrowings	2,219	969	1,537
Net proceeds from short-term borrowings		181	
Repayments of borrowings	(2,749)	(623)	(504)
Net cash flow from commercial paper and revolving lines of credit	(128)	(724)	599
Payment to ChevronTexaco for Series B preferred stock restructuring	(225)		

Proceeds from issuance of capital stock	6	240	604
Proceeds from issuance of convertible preferred stock			1,500
Purchase of serial preferred securities of a subsidiary		(28)	
Purchase of treasury stock		(1)	(68)
Redemption of Illinois Power Preferred Securities			(100)
Dividends and other distributions, net		(55)	(98)
Decrease (increase) in restricted cash	(2)	11	(1)
Other financing, net	(21)	(14)	(19)
Net cash provided by (used in) financing activities	(900)	(44)	3,450
Effect of exchange rate changes on cash	10	(59)	(23)
Net increase (decrease) in cash and cash equivalents	(280)	549	149
Cash and cash equivalents, beginning of period	757	208	59
Cash and cash equivalents, end of period	$ 477	$ 757	$ 208

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

(RESTATED)

See Explanatory Note

(in millions)

	Common Stock	Additional Paid-In Capital	Subscriptions Receivable	Accumulated Other Comprehensive Loss	Retained Earnings (Accumulated Deficit)	Treasury Stock	Total
December 31, 2000	$ 2,912	$ 15	$	$ (15)	$ 496	$ (3)	$ 3,405
Net income					399		399
Other comprehensive loss, net of tax				(12)			(12)
Common Stock issued	605						605
Subscriptions receivable			(38)				(38)
Implied dividend on Series B Preferred Stock		660					660
Options exercised	57						57
Dividends and other distributions					(140)		(140)
401(k) plan and profit sharing stock	13						13
Options granted		13					13
Treasury stock						(68)	(68)
December 31, 2001	$ 3,587	$ 688	$ (38)	$ (27)	$ 755	$ (71)	$ 4,894
Net loss					(2,578)		(2,578)
Other comprehensive loss, net of tax				(28)			(28)
Differential of Series A Preferred Purchase		7					7
Common Stock issued	205						205
Subscriptions receivable			26				26
Options exercised	22						22
Dividends and other distributions					(375)		(375)
401(k) plan and profit sharing stock	17						17
Options granted		11					11
Treasury stock		(1)				3	2
December 31, 2002	$ 3,831	$ 705	$ (12)	$ (55)	$ (2,198)	$ (68)	$ 2,203
Net loss					(667)		(667)
Other comprehensive income, net of tax				35			35
Series B Preferred Stock restructuring		(660)			1,224		564
Subscriptions receivable			4				4
Options exercised	15	(6)					9
Dividends and other distributions					(211)		(211)
401(k) plan and profit sharing stock	8						8
Options granted		2					2

December 31, 2003	$ 3,854	$ 41	$ (8)	$ (20)	$ (1,852)	$ (68)	$ 1,947

See the notes to the consolidated financial statements.

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DYNEGY INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(RESTATED)

See Explanatory Note

(in millions)

	Year Ended December 31,		
	2003	2002	2001
Net income (loss)	$ (667)	$ (2,578)	$ 399
Cash flow hedging activities, net:			
Cumulative effect of transition adjustment			61
Unrealized mark-to-market gains arising during period, net	39	73	4
Reclassification of mark-to-market (gains) losses to earnings, net	(37)	(73)	(57)
Changes in cash flow hedging activities, net (net of tax expense of $1, zero and $5, respectively)	2		8
Foreign currency translation adjustments	24	31	(21)
Minimum pension liability (net of tax benefit (expense) of $(5), $38 and zero, respectively)	9	(66)	
Unrealized gains on securities, net:			
Unrealized holding losses arising during period, net			(11)
Less: Reclassification adjustments for losses realized in net income (loss)		7	12
Net unrealized gains (net of tax expense of zero, $3 and zero, respectively)		7	1
Other comprehensive income (loss), net of tax	35	(28)	(12)
Comprehensive income (loss)	$ (632)	$ (2,606)	$ 387

See the notes to the consolidated financial statements.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(RESTATED)

PLEASE NOTE THAT THESE FINANCIAL STATEMENTS AND THE NOTES THERETO DO NOT REFLECT EVENTS OCCURRING AFTER FEBRUARY 27, 2004 (THE DATE OF THE ORIGINAL FILING). FOR A DESCRIPTION OF THESE EVENTS, PLEASE READ OUR EXCHANGE ACT REPORTS FILED SINCE FEBRUARY 27, 2004, INCLUDING OUR QUARTERLY REPORTS ON FORM 10-Q FOR THE PERIODS ENDED MARCH 31, 2004, JUNE 30, 2004 AND SEPTEMBER 30, 2004, OUR CURRENT REPORTS ON FORM 8-K AND ANY AMENDMENTS THERETO.

EXPLANATORY NOTE

This Amendment No. 2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2003 includes restatements of our consolidated financial statements for each of the three years in the period ended December 31, 2003. The restatements relate to an increased impairment associated with the sale of Illinois Power and our deferred income tax accounts. Quarterly information in this Explanatory Note is unaudited. Specifically, the restatements are as follows:

Impairment of Illinois Power. As more fully discussed in Note 10 Goodwill beginning on page F-38, during 2003, the value of goodwill associated with Illinois Power was determined to be impaired, resulting in our recognizing a charge of $242 million. During 2004, while preparing to record the Illinois Power sale, we identified a deferred tax asset that was excluded from our 2003 impairment analysis. Our exclusion of this asset understated the net book value of the assets and, as a result, understated the impairment that had been recorded in 2003. The impact of the error resulted in an after-tax understatement of goodwill impairment of $139 million and an after-tax understatement of asset impairments of $120 million. As such, we recognized an additional after-tax charge of $259 million ($0.61 per diluted share) in 2003. This correction had no impact on our previously reported net cash provided by (used in) operating activities, investing activities or financing activities.

The table below reflects the quarterly and year-to-date impact of the additional impairments on net income as originally reported.

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
			(in millions)			
2003	$	$	$	$	$	$ (259)

Deferred Income Tax Accounts. As previously disclosed in our second quarter 2004 Form 10-Q, we undertook an evaluation of our tax accounting and reconciliation controls and processes, including a tax basis balance sheet review which we have recently completed. Through this initiative, we determined that adjustments related to our deferred income tax accounts in periods prior to 2004 are required. These adjustments primarily related to errors associated with accounting for acquisitions, incorrect classification of goodwill impairments as permanent differences for purposes of calculating the tax provision and other items. As a result of these errors, adjustments were also made to goodwill and other long-term liabilities accounts.

This restatement has no effect on our previously reported net cash provided by (used in) operating activities, investing activities or financing activities.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

The table below reflects the quarterly and year-to-date impact of the correction to our previous accounting for income taxes on net income as originally reported.

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Month Ended December 31	Six Months Ended June 30	Nine Months Ended September 30	Twelve Months Ended December 31
				(in millions)			
2000 and prior							$ (36)
2001							(7)
2002	$ (1)	$	$ 170	$ (10)	$ (1)	$ 169	159
2003				45			45

Summary. A synopsis of the aggregate financial impact of these restatements on the amounts originally reported in the Original Filing is as follows:

RESTATED SELECTED BALANCE SHEET DATA

	December 31, 2003	December 31, 2002
	(in millions)	
Property, Plant and Equipment, Net		
As previously reported	$ 8,396	$ 8,458
Impairment of Illinois Power	(193)	
As restated	$ 8,203	$ 8,458
Goodwill		
As previously reported	$ 154	$ 396
Impairment of Illinois Power	(139)	
Deferred income tax accounts		(70)
As restated	$ 15	$ 326
Total Assets		

As previously reported	$ 13,293	$ 20,099
Impairment of Illinois Power	(332)	
Deferred income tax accounts		(70)
As restated	$ 12,961	$ 20,029
Deferred income taxes		
As previously reported	$ 751	$ 951
Impairment of Illinois Power	(73)	
Deferred income tax accounts	(154)	(186)
As restated	$ 524	$ 765
Other long-term liabilities		
As previously reported	$ 750	$ 924
Deferred income tax accounts	(7)	
As restated	$ 743	$ 924
Total Liabilities		
As previously reported	$ 10,716	$ 16,443
Impairment of Illinois Power	(73)	
Deferred income tax accounts	(161)	(186)
As restated	$ 10,482	$ 16,257
Stockholders Equity		
As previously reported	$ 2,045	$ 2,087
Impairment of Illinois Power	(259)	
Deferred income tax accounts	161	116
As restated	$ 1,947	$ 2,203

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

RESTATED SELECTED RESULTS OF OPERATIONS DATA

	Year Ended December 31,		
	2003	**2002**	**2001**
Depreciation and amortization expense			
As previously reported	$ (454)	$ (466)	$ (456)
Deferred income tax accounts			4
As restated	$ (454)	$ (466)	$ (452)
Goodwill impairment			
As previously reported	$ (242)	$ (897)	$
Impairment of Illinois Power	(139)		
Deferred income tax accounts	70	83	
As restated	$ (311)	$ (814)	$
Impairment and other charges			
As previously reported	$ (7)	$ (190)	$
Impairment of Illinois Power	(193)		
As restated	$ (200)	$ (190)	$
Income tax benefit (expense)			
As previously reported	$ 198	$ 276	$ (357)
Impairment of Illinois Power	73		
Deferred income tax accounts	(25)	76	(11)
As restated	$ 246	$ 352	$ (368)
Net income (loss)			
As previously reported	$ (453)	$ (2,737)	$ 406
Impairment of Illinois Power	(259)		
Deferred income tax accounts	45	159	(7)
As restated	$ (667)	$ (2,578)	$ 399
Net income (loss) available to common stockholders			

As previously reported	$ 560	$ (3,067)	$ 364
Impairment of Illinois Power	(259)		
Deferred income tax accounts	45	159	(7)
As restated	$ 346	$ (2,908)	$ 357
Earnings (loss) per diluted share			
As previously reported	$ 1.35	$ (8.38)	$ 1.07
Impairment of Illinois Power	(0.61)		
Deferred income tax accounts	0.10	0.43	(0.02)
As restated	$ 0.84	$ (7.95)	$ 1.05

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(RESTATED)

Note 1 Organization and Operations of the Company

Dynegy Inc. (together with our subsidiaries, we , us or our) is a holding company and conducts substantially all of our business through our subsidiaries. We own operating divisions engaged in power generation, natural gas liquids and regulated energy delivery. We also separately report the results of our customer risk management business. We had four reportable business segments in 2003: GEN, NGL, REG and CRM. We reported our results in these four business segments based on the diversity of their respective operations. Please see a description of abbreviations used in these footnotes beginning on page F-88.

Note 2 Accounting Policies

Our accounting policies conform to GAAP. Our most significant accounting policies are described below. The preparation of consolidated financial statements in conformity with GAAP requires management to develop estimates and to make assumptions that affect reported financial position and results of operation. These estimates and assumptions also impact the nature and extent of disclosure, if any, of contingent liabilities. We review significant estimates affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Judgments and estimates are based on our beliefs and assumptions derived from information available at the time such estimates are made. Adjustments made with respect to the use of these estimates often relate to information not previously available. Uncertainties with respect to such estimates and assumptions are inherent in the preparation of financial statements. Estimates are primarily used in (1) developing fair value assumptions, including estimates of future cash flows and discounts rates, (2) analyzing tangible and intangible assets for possible impairment, (3) estimating the useful lives of our assets, (4) assessing future tax exposure and the realization of tax assets, (5) determining amounts to accrue for contingencies and (6) estimating various factors used to value our pension assets. Actual results could differ materially from any such estimates.

Principles of Consolidation. The accompanying consolidated financial statements include our accounts and the accounts of our majority-owned or controlled subsidiaries, and our proportionate share of assets, liabilities, revenues and expenses of undivided interests in certain gas processing facilities, after eliminating intercompany accounts and transactions. Certain reclassifications have been made to prior-period amounts to conform with current-period financial statement classifications.

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

Restricted Cash. Restricted cash represents cash that is unavailable for general purpose cash needs. Restricted cash reflects amounts reserved for use in retiring Illinois Power s Transitional Funding Trust Notes. This is further discussed in Note 12 Debt Illinois Power Transitional Funding Trust Notes beginning on page F-46.

Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivable if it is reasonable to assume we will not collect all or part of outstanding balances. We review collectibility and establish or adjust our allowance as necessary primarily using a percent of balance methodology. The specific identification method is also used in certain circumstances.

Investment in Unconsolidated Affiliates. Investments in affiliates over which we may exercise significant influence, generally 20% to 50% ownership interests, are accounted for using the equity method. Any excess of our investment in affiliates, as compared to our share of the underlying equity, that is not recognized as goodwill is amortized over the estimated economic service lives of the underlying assets. Other investments over which

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

we may not exercise significant influence and that have readily determinable fair values are considered available-for-sale and are recorded at quoted market values or at the lower of cost or net realizable value, if there are no readily determinable fair values. For securities with readily determinable fair values, the change in the unrealized gain or loss, net of deferred income tax, is recorded as a separate component of accumulated other comprehensive income (loss) in the consolidated statements of comprehensive income (loss). Realized gains and losses on investment transactions are determined using the specific identification method. All investments in unconsolidated affiliates are periodically assessed for other-than-temporary declines in value, with write-downs recognized in earnings (losses) from unconsolidated investments in the consolidated statements of operations.

Concentration of Credit Risk. We sell our energy products and services to customers in the electric and gas distribution industries and to entities engaged in industrial and petrochemical businesses. These industry concentrations have the potential to impact our overall exposure to credit risk, either positively or negatively, because the customer base may be similarly affected by changes in economic, industry, weather or other conditions.

Inventory. Our natural gas, natural gas liquids, coal and crude oil inventories are valued at the lower of weighted average cost or at market. Our materials and supplies inventory is carried at the lower of cost or market using the specific identification method.

Property, Plant and Equipment. Property, plant and equipment, which has consisted principally of gas gathering, processing, fractionation, terminalling and storage facilities, natural gas transportation and electric transmission lines, pipelines and power generating facilities, is recorded at historical cost. Expenditures for major replacements, renewals and major maintenance are capitalized. We consider major maintenance to be expenditures incurred on a cyclical basis to maintain and prolong the efficient operation of our assets. Expenditures for repairs and minor renewals to maintain assets in operating condition are expensed. Depreciation is provided using the straight-line method over the estimated economic service lives of the assets, ranging from three to 60 years. Composite depreciation rates (composite rates) are applied to functional groups of assets having similar economic characteristics. The estimated economic service lives of our functional asset groups are as follows:

Asset Group	Range of Years
Power Generation Facilities	27 to 40
Natural Gas Gathering Systems and Processing Facilities	14 to 25
Fractionation, Terminaling and Natural Gas Liquids Storage Facilities	14 to 25
Transportation Equipment	5 to 10
Regulated Electric Assets	21 to 60
Regulated Gas Assets	27 to 50
Regulated Other Assets	14 to 46
Buildings and Improvements	10 to 40
Office and Miscellaneous Equipment	3 to 35

Gains and losses are not recognized for retirements of property, plant and equipment subject to composite rates until the asset group subject to the composite rate is retired. Gains and losses on sales of individual assets are reflected in gain on sale of assets in the consolidated statements of operations. Through December 31, 2001, we reviewed the carrying value of our long-lived assets in accordance with SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed of. In August 2001, the FASB

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which addresses the accounting and reporting for the impairment or disposal of long-lived assets and supersedes SFAS No. 121 and APB Opinion No. 30, Reporting the Results of Operations Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions. Under this standard, we evaluate an asset for impairment when events or circumstances indicate its carrying value may not be recovered. These events include market declines, changes in the manner in which we intend to use an asset or decisions to sell an asset and adverse changes in the legal or business environment. When we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to the estimated sales price, less costs to sell. Our adoption of SFAS No. 144 on January 1, 2002 did not have any impact on our financial position or results of operations. See Note 4 Restructuring and Impairment Charges beginning on page F-26 for a discussion of impairment charges we recognized in 2002 and 2003.

Asset Retirement Obligations. In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. We adopted SFAS No. 143, which provides accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets, effective January 1, 2003. Under SFAS No. 143, an ARO is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted towards the ultimate obligation amount and the capitalized ARO costs are depreciated over the useful life of the related asset.

As part of the transition adjustment in adopting SFAS No. 143, existing environmental liabilities in the amount of $73 million were reversed in the first quarter 2003. The fair value of the remediation costs estimated to be incurred upon retirement of the respective assets is included in the ARO and was recorded upon adoption of SFAS No. 143. Since the previously accrued liabilities exceeded the fair value of the future retirement obligations, the impact of adopting SFAS No. 143 was an increase in earnings, net of tax, of $34 million in the first quarter 2003, which is included in cumulative effect of change in accounting principles in the consolidated statements of operations. In addition to these liabilities, we also have potential retirement obligations for dismantlement of power generation facilities, power transmission assets, a fractionation facility and natural gas storage facilities. Our current intent is to maintain these facilities in a manner such that they will be operated indefinitely. As such, we cannot estimate any potential retirement obligations associated with these assets. Liabilities will be recorded in accordance with SFAS No. 143 at the time we are able to estimate any new AROs.

At January 1, 2003, our ARO liabilities were $26 million for our GEN segment, $9 million for our NGL segment and $6 million for our REG segment. These retirement obligations relate to activities such as ash pond and landfill capping, closure and post-closure costs, environmental testing, remediation, monitoring and land and equipment lease obligations. Annual amortization of the assets resulting from adoption of this standard and the accretion of the liability towards the ultimate obligation amount was $7 million in 2003. During 2003, accretion expense recognized for the fair value for all of our ARO liabilities totaled $5 million. There were no additional AROs recorded or settled during 2003. During 2003, we changed the estimated timing of our estimated cash flows associated with our ARO liability in the REG segment due to delivery of notice of our intention to exercise our option to purchase the Tilton turbines, as further described at Note 12 Debt Tilton Capital Lease beginning on page F-46, and reduced the liability by $5 million, accordingly. At December 31, 2003, our ARO liabilities were $30 million for our GEN segment, $10 million for our NGL segment and $1 million for our REG segment.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

The following pro forma financial information has been prepared to give effect to the adoption of SFAS No. 143 as if it had been adopted January 1, 2001:

	Year Ended December 31,	
	2002	2001
	(in millions)	
Income (loss) from continuing operations, as reported	$ (1,190)	$ 479
Pro forma adjustments to reflect retroactive adoption of SFAS No. 143	(6)	(5)
Pro forma income (loss) from continuing operations	(1,196)	$ 474
Income (loss) before cumulative effect of change in accounting principles, as reported	$ (2,344)	$ 397
Pro forma adjustments to reflect retroactive adoption of SFAS No. 143	(6)	(5)
Pro forma income (loss) before cumulative effect of change in accounting principles	$ (2,350)	$ 392
Net income (loss), as reported	$ (2,578)	$ 399
Pro forma adjustments to reflect retroactive adoption of SFAS No. 143	(4)	(3)
Pro forma net income (loss)	$ (2,582)	$ 396

	2002		2001	
	As Reported	Pro Forma	As Reported	Pro Forma
Basic earnings (loss) per share				
Income (loss) from continuing operations	$ (4.16)	$ (4.17)	$ 1.35	$ 1.34
Loss from discontinued operations	(3.15)	(3.15)	(0.26)	(0.26)
Cumulative effect of change in accounting principles, net	(0.64)	(0.64)	0.01	0.01
Basic earnings (loss) per share	$ (7.95)	$ (7.96)	$ 1.10	$ 1.09

	2002	2001

	As Reported	Pro Forma	As Reported	Pro Forma
Diluted earnings (loss) per share				
Income (loss) from continuing operations	$ (4.16)	$ (4.17)	$ 1.29	$ 1.28
Income (loss) from discontinued operations	(3.15)	(3.15)	(0.25)	(0.25)
Cumulative effect of change in accounting principles, net	(0.64)	(0.64)	0.01	0.01
Diluted earnings (loss) per share	$ (7.95)	$ (7.96)	$ 1.05	$ 1.04

The following table presents the AROs that would have been included in other long-term liabilities on our consolidated balance sheets if SFAS No. 143 had been adopted January 1, 2001:

	2002	2001
	(in millions)	
Balance, beginning of year	$ 36	$ 30
Liabilities incurred	1	2
Accretion expense	4	4
Balance, end of year	$ 41	$ 36

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Other Contingencies. Environmental costs relating to current operations are expensed or capitalized, as appropriate, depending on whether they provide future economic benefit. Liabilities are recorded when environmental assessment indicate remedial efforts are probable and the costs can be reasonably estimated. Measurement of liabilities is based on currently enacted laws and regulations, existing technology and site-specific costs. Liabilities may be recognized on a discounted basis if the amount and timing of anticipated expenditures are fixed or reliably determinable; otherwise, such liabilities are recognized on an undiscounted basis. Liabilities incurred by providing indemnification in connection with assets sold or closed are recognized upon such sale or closure to the extent they are probable, can be estimated and have not previously been reserved. In assessing liabilities, no offset is made for potential insurance recoveries. Recognition of any joint and several liability is based upon our best estimate of our final pro rata share of such liability.

Liabilities for other contingencies are recognized in accordance with SFAS No. 5 upon identification of an exposure, which, when fully analyzed, indicates that it is both probable a liability has been incurred and the loss amount can be reasonably estimated. Non-capital costs to remedy such contingencies or other exposures are charged to a reserve, if one exists, or otherwise to current-period operations. We accrue the lesser end of the range when a range of probable loss exists.

Goodwill and Other Intangible Assets. Prior to January 1, 2002, intangible assets, principally goodwill, were amortized on a straight-line basis over their estimated useful lives of 25 to 40 years. However, we adopted SFAS No. 142 effective January 1, 2002, and, accordingly, discontinued amortizing goodwill. In accordance with SFAS No. 142, we subject goodwill to a fair value-based impairment test on at least an annual basis. As further discussed in Note 10 Goodwill beginning on page F-38, with the adoption of SFAS No. 142 and the resulting impairment test, we recognized a $234 million charge in our communications business associated with the cumulative effect of implementing this standard. In addition, we recognized an $814 million goodwill impairment in 2002 related to the CRM and GEN segments and a $311 million goodwill impairment in 2003 related to the REG segment. The estimation of fair value is highly subjective, inherently imprecise and can change materially from period to period based on, among other things, an assessment of market conditions, projected cash flows and discount rate. We currently perform our annual impairment test in the fourth quarter after our annual budgetary process, and we may record further impairment losses in future periods as a result of such test.

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 whether to apply one comprehensive accounting model rather than the other based on guidance provided by the FASB and the SEC.

The accrual model has historically been used to account for substantially all of the operations conducted in the GEN, NGL and REG segments. Revenues from power generation are recognized upon output, product delivery or satisfaction of specific targets, all as specified by contractual terms. Revenues for product sales, gas processing, storage and marketing and refinery services are recognized when title passes to the customer or when the service is performed. Fractionation and transportation revenues are recognized based on volumes received in accordance with contractual terms. Our transmission, distribution and retail electric and natural gas services revenues are recognized when services are provided to customers. Shipping and handling costs are included in revenue when billed to customers with the sale of products.

The fair value model is used to account for certain forward physical and financial transactions, primarily in the GEN and CRM segments, which meet criteria defined by FASB for derivative instruments. These criteria

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

require these contracts to relate to future periods, to contain price and volume components and to have terms that require or permit net settlement of the contract in cash or its 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. The net gains or losses resulting from the revaluation of these contracts during the period are recognized currently in our consolidated statements of operations unless such contracts qualify and are designated as cash flow hedges, in which case the same gains or losses are recorded in other comprehensive income (loss) until such time as the hedged transaction occurs. If the underlying transaction being hedged by the commodity, interest rate or foreign currency transaction is disposed of or otherwise terminated, the gain or loss associated with such contract is no longer deferred and is recognized in the period the underlying contract is eliminated. Subsequent gains and losses associated with the change in value of interest rate or foreign currency instruments are recognized in other income and expense, net, unless the instrument is redesignated as a hedge. If the hedging transaction is terminated prior to the occurrence of the underlying transaction being hedged, the gain or loss associated with the hedging transaction is deferred and recognized in income in the period in which the underlying transaction being hedged occurs. Assets and liabilities associated with these transactions are reflected on our consolidated balance sheets as risk-management assets and liabilities and classified as short- (i.e., current) or long-term pursuant to each contract s individual length.

We estimate the fair value of our marketing portfolio using a liquidation value approach assuming that our ability to transact business in the market remains at historical levels. The estimated fair value of our portfolio is computed by multiplying all existing positions in our portfolio by estimated prices, reduced by a LIBOR-based 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 or, if market quotes are unavailable, (2) prices from a proprietary model that incorporates forward energy prices derived from market quotes and values from executed transactions.

In 2002, the EITF reached consensuses on several issues pursuant to Issue 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities. First, the EITF concluded that all mark-to-market gains and losses on energy trading contracts (whether realized or unrealized) should be shown net in the income statement, regardless of whether the contract is physically or financially settled. In the third quarter 2002, we began presenting all mark-to-market gains and losses on a net basis in the consolidated statements of operations to reflect this change in accounting principle.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Second, in October 2002, as an additional component of EITF Issue 02-03, the EITF rescinded EITF Issue 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, which previously required use of mark-to-market accounting for our energy trading contracts. While the rescission of EITF Issue 98-10 reduced the number of contracts accounted for on a mark-to-market basis, it did not eliminate mark-to-market accounting. All derivative contracts that either do not qualify, or are not designated, as hedges or as normal purchases or sales, as defined by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, continue to be marked-to-market in accordance with SFAS No. 133. Any earnings or losses previously recognized under EITF Issue 98-10 that would not have been recognized under SFAS No. 133 were reversed in 2003 pursuant to adopting the provisions of EITF Issue 02-03. The cumulative effect of this change in accounting principle resulted in after-tax earnings of $21 million in 2003 and comprised the following items that are no longer required to be recorded using mark-to-market accounting (in millions):

Removal of net risk-management assets representing the value of natural gas storage contracts	$ (176)
Removal of other net risk-management assets	(24)
Removal of net risk-management liabilities representing the value of power tolling arrangements	103
Net change in risk-management assets and liabilities	(97)
Addition of inventory previously included in risk-management assets (1)	130
Pre-tax gain recorded from change in accounting principle	33
Income tax provision	(12)
After-tax gain recorded in the consolidated statements of operations.	$ 21

(1) All of the natural gas inventory was sold during 2003.

Cash inflows and outflows associated with the settlement of risk management activities are recognized in operating cash flows.

Income Taxes. We file a consolidated U.S. federal income tax return and, for financial reporting purposes, account for income taxes using the liability method in accordance with SFAS No. 109, Accounting for Income Taxes. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities caused by differences between financial statement carrying amounts and the tax bases of certain assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. Valuation allowances are provided against deferred tax assets when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates used to recognize deferred tax assets are subject to revision, either higher or lower, in future periods based on new facts or circumstances.

Earnings Per Share. Basic earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period. Diluted earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period plus each share that would have been outstanding assuming the issuance of common shares for all potentially dilutive common shares outstanding during the period.

Foreign Currency. For subsidiaries whose functional currency is not the U.S. Dollar, assets and liabilities are translated at year-end rates of exchange and revenues and expenses are translated at monthly average exchange rates. Translation adjustments for the asset and liability accounts are included as a separate component of accumulated other comprehensive loss in stockholders equity.

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Currency transaction gains and losses are recorded in other income and expense, net on the consolidated statements of operations and totaled gains of $12 million, gains of $4 million and losses of $18 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Employee Stock Options. In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. SFAS No. 148 amends SFAS No. 123, Accounting for Stock-Based Compensation, and provides alternative methods of transition (prospective, modified prospective or retroactive) for entities that voluntarily change to the fair value-based method of accounting for stock-based employee compensation in a fiscal year beginning before December 16, 2003. SFAS No. 148 requires prominent disclosure about the effects on reported net income of an entity s accounting policy decisions with respect to stock-based employee compensation. We transitioned to a fair value-based method of accounting for stock-based compensation in the first quarter 2003 and are using the prospective method of transition as described under SFAS No. 148. As a result, a charge of approximately $1 million is included in general and administrative expenses for the year ended December 31, 2003.

Under the prospective method of transition, all stock options granted after January 1, 2003 are accounted for on a fair value basis. Options granted prior to January 1, 2003 continue to be accounted for using the intrinsic value method. Accordingly, for options granted prior to January 1, 2003, compensation expense is not reflected for employee stock options unless they were granted at an exercise price lower than market value on the grant date. We have granted in-the-money options in the past and continue to recognize compensation expense over the applicable vesting periods. No in-the-money stock options have been granted since 2001.

Had compensation cost for all stock options granted prior to 2003 been determined on a fair value basis consistent with SFAS No. 123, our net income (loss) and basic and diluted earnings (loss) per share amounts would have approximated the following pro forma amounts for the years ended December 31, 2003, 2002 and 2001, respectively.

	Years Ended December 31,		
	2003	2002	2001
	(in millions, except per share data)		
Net income (loss) as reported	$ (667)	$ (2,578)	$ 399
Add: Stock-based employee compensation expense included in reported net income (loss), net of related tax effects	2	8	9
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(53)	(84)	(67)
Pro forma net income (loss)	$ (718)	$ (2,654)	$ 341

Earnings (loss) per share:			
Basic as reported	$ 0.93	$ (7.95)	$ 1.10
Basic pro forma	$ 0.79	$ (8.16)	$ 0.92
Diluted as reported	$ 0.84	$ (7.95)	$ 1.05
Diluted pro forma	$ 0.72	$ (8.16)	$ 0.88

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions used for grants in 2003, 2002 and 2001: dividends per year of zero for 2003, $0.15 for 2002 and $0.30 per share for 2001; expected volatility of 89.6%, 74.3% and 46.4%, respectively; a risk-free interest rate of 3.9%, 4.2% and 4.3%, respectively; and an expected option life of 10 years for all periods.

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Regulatory Assets and Liabilities. SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, allows companies whose service obligations and prices are regulated to maintain balance sheet assets representing costs they expect to recover from customers through inclusion in future rates. Illinois Power, our wholly owned utility subsidiary, records regulatory assets in accordance with SFAS No. 71. Regulatory assets at December 31, 2003 and 2002 totaled approximately $207 million and $256 million, respectively, and are included in other long-term assets on our consolidated balance sheets. The investment tax credit related to regulatory assets is amortized over the lives of the respective assets which gave rise to the investment tax credit.

Rate-regulated companies subject to SFAS No. 71 are permitted to accrue the estimated cost of removal and salvage associated with certain of their assets through depreciation expense. The amounts accrued in depreciation are not associated with AROs recorded in accordance with SFAS No. 143. We estimate that as of December 31, 2002, approximately $69 million of cost of removal, net of salvage, allowed under rate regulation was included in accumulated depreciation. With the adoption of SFAS No. 143, we reclassified this amount from accumulated depreciation to regulatory liabilities. At December 31, 2003, approximately $72 million of cost of removal, net of salvage, was included in regulatory liabilities.

Minority Interest. Minority interest on the consolidated balance sheets includes third-party investments in entities that we consolidate, but do not wholly own. The net pre-tax results attributed to minority interest holders in consolidated entities are included in minority interest income (expense) in the consolidated statements of operations.

Accounting Principles Adopted

SFAS No. 132. In December 2003, the FASB released SFAS No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits. The revised standard requires disclosures for pensions and other postretirement benefit plans and replaces existing pension disclosure requirements. We adopted the new disclosure requirements as of December 31, 2003. Please see Note 20 Employee Compensation, Savings and Pension Plans beginning on page F-74 for these required disclosures.

SFAS No. 143. In June 2001, the FASB issued SFAS No. 143, which we adopted January 1, 2003. For further discussion, please see Asset Retirement Obligations beginning on page F-13.

SFAS No. 146. In July 2002, the FASB issued SFAS No. 146, Accounting for Exit or Disposal Activities, which addresses the recognition, measurement and reporting of costs associated with exit and disposal activities, including restructuring activities previously accounted for pursuant to the guidance in EITF Issue 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). SFAS No. 146 is effective for exit or disposal activities initiated after December 31, 2002. The application of SFAS No. 146 during 2003 did not have a material impact on our financial statements.

SFAS No. 148. In December 2002, the FASB issued SFAS No. 148. We transitioned to a fair value-based method of accounting for stock-based compensation in the first quarter 2003 and are using the prospective method of transition as described under SFAS No. 148. For further discussion, please see Employee Stock Options beginning on page F-18.

SFAS No. 149. In April 2003, the FASB issued SFAS No. 149, Amendment of SFAS No. 133 on Derivative Instruments and Hedging Activities, which clarifies and amends various issues related to derivatives

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and financial instruments addressed in SFAS No. 133 and interpretations issued by the Derivatives Implementation Group. In particular, SFAS No. 149: (1) clarifies when a contract with an initial net investment meets the characteristics of a derivative; (2) clarifies when a derivative contains a financing component that should be recorded as a financing transaction on the balance sheet and the statement of cash flows; (3) amends the definition of an underlying in SFAS No. 133 to conform to the language used in FIN No. 45; and (4) clarifies other derivative concepts. SFAS No. 149 is applicable to all contracts entered into or modified after June 30, 2003 and to all hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 did not materially impact our financial statements.

SFAS No. 150. In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, which establishes how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. Instruments that have an unconditional obligation requiring the issuer to redeem the instrument by transferring an asset at a specified date are required to be classified as liabilities on the balance sheet. Instruments that require the issuance of a variable number of equity shares by the issuer generally do not have the risks associated with equity instruments and as such should also be classified as liabilities on the balance sheet. SFAS No. 150 was effective for contracts in existence or created or modified for the first interim period beginning after June 15, 2003. Upon adoption, we reclassified approximately $200 million of Company Obligated Preferred Securities (now referred to as Subordinated Debentures), previously recorded in the mezzanine section of our balance sheet between liabilities and stockholders equity, to long-term liabilities. Accordingly, the interest related to this instrument is recorded as interest expense beginning July 1, 2003. Prior year amounts have not been reclassified to conform to this change. Previously, the preferred return on this instrument was reported in accumulated distributions associated with trust preferred securities in the consolidated statements of operations. Further, the $400 million in Series C convertible preferred stock issued in August 2003 in connection with the Series B Exchange is classified within the mezzanine section of our consolidated balance sheets due to the $5.78 per share substantive conversion option, which renders the mandatory redemption feature contingent upon the holder not exercising its conversion option. See Note 11 Refinancing and Restructuring Transactions Series B Exchange beginning on page F-40 for further discussion.

FIN No. 45. In November 2002, the FASB issued FIN No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. As required by FIN No. 45, we adopted the disclosure requirements on December 31, 2002. On January 1, 2003, we adopted the initial recognition and measurement provisions for guarantees issued or modified after December 31, 2002. The adoption of the recognition and measurement provisions did not materially impact our financial statements.

FIN No. 46. In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities An Interpretation of ARB No. 51. In December 2003, the FASB issued the updated and final interpretation FIN No. 46R. FIN No. 46R requires that an equity investor in a variable interest entity have significant equity at risk (generally a minimum of 10%, which is an increase from the 3% required under previous guidance) and hold a controlling interest, evidenced by voting rights, and absorb a majority of the entity s expected losses, receive a majority of the entity s expected returns, or both. If the equity investor is unable to evidence these characteristics, the entity that retains these ownership characteristics will be required to consolidate the variable interest entity as the primary beneficiary. FIN No. 46 was applicable immediately to variable interest entities created or obtained after January 31, 2003. While we have not entered into any arrangements in 2003 that would be subject to FIN No. 46, entities previously formed are impacted. FIN No. 46R was effective on December 31, 2003 for interests in entities that were previously considered special purpose entities under then existing authoritative guidance. We recorded a cumulative effect of change in accounting

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principle of $15 million after-tax related to our adoption of this portion of FIN No. 46R, as further described below. Please also see Note 12 Debt Illinois Power Transitional Funding Trust Notes beginning on page F-46 and Note 15 Redeemable Preferred Securities Subordinated Debentures beginning on page F-54. We will adopt FIN No. 46R for non-special purpose entities on March 31, 2004. We are in the process of assessing the impact, if any, that this adoption will have on our financial statements.

CoGen Lyondell, Inc. (CLI) is the lessee of the CoGen Facility, a 610 MW gas-fueled combined-cycle co-generation plant that sells steam and electricity to the Lyondell Chemical Complex and sells electricity to the open wholesale market in ERCOT. Additionally, CoGen Lessor is a synthetic lease entity which leases the CoGen Facility to CLI. Both entities were previously considered special purpose entities and also met the definition of a VIE because their equity holders did not have a controlling interest or significant equity investment at risk in the entity. We were considered the primary beneficiary of both entities as we held a fixed-price purchase option on the assets of the entities during the lease term and maintained a residual value guarantee for 97% of the facility on CoGen Lessor. FIN No. 46R does not impact our accounting for CLI, as we have always consolidated CLI. Additionally, we began accounting for our lease with CoGen Lessor as a capital lease in June 2002, and, therefore, began consolidating the generation facility and the associated debt. The $15 million cumulative effect noted above is primarily a result of recording additional accumulated depreciation on the facility from June 1997, inception of the leasing arrangement, through June 2002. If we had adopted this portion of FIN No. 46R on January 1, 2001, our income (loss) before cumulative effect of change in accounting principles would have increased (decreased) by zero, $(1) million and $(3) million for the years ended December 31, 2003, 2002 and 2001, respectively. Our net income (loss) would have increased (decreased) by $15 million, $(1) million and $(3) million for the years ended December 31, 2003, 2002 and 2001, respectively. Our basic and diluted earnings per share would have increased (decreased) by $0.04, zero and $(0.01) for the years ended December 31, 2003, 2002 and 2001, respectively. We retired the $170 million capital lease obligation with proceeds received from our October 2003 follow-on notes offering further described in Note 11 Refinancing and Restructuring Transactions Follow-on Notes Offering beginning on page F-40.

EITF Issue 02-03. During 2002, the EITF reached consensus on several issues pursuant to EITF Issue 02-03. For further discussion, please see Revenue Recognition beginning on page F-15.

EITF Issue 03-11. In July 2003, the EITF reached consensus on Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , and Not Held for Trading Purposes as Defined in EITF Issue 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities. The consensus stated that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. The consideration of the facts and circumstances, including economic substance, should be made in the context of the various activities of the entity rather than based solely on the terms of the individual contracts. We were not materially impacted by the adoption of EITF Issue 03-11.

Note 3 Discontinued Operations, Dispositions, Contract Terminations and Acquisitions

Discontinued Operations

During 2002, we sold our ownership interests in Northern Natural, our U.K. natural gas storage business and our global liquids business. In addition, as part of our restructuring plan, we sold or liquidated additional portions of our operations during 2003, including our communications business and our U.K. CRM business, some of which have been accounted for as discontinued operations under SFAS No. 144, as further described below.

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Northern Natural. In November 2001, we acquired 1,000 shares of Northern Natural Series A Preferred Stock for $1.5 billion. DHI, our wholly owned subsidiary, concurrently acquired an option to purchase all of the equity of Northern Natural s indirect parent company. DHI exercised its option in November 2001 upon termination of a merger agreement with Enron, and closing of the option exercise occurred on January 31, 2002.

On August 16, 2002, we sold Northern Natural to MidAmerican for $879 million in cash, net of working capital adjustments. Under the terms of this agreement, MidAmerican acquired all of the common and preferred stock of Northern Natural and assumed all of Northern Natural s $950 million of debt. We incurred a pre-tax loss in 2002 of $599 million ($561 million after-tax) associated with the sale, including adjustments for changes in working capital. NNG s results of operations are included as a discontinued operation in our consolidated statements of operations, as part of our REG segment.

For federal income tax purposes, the sale resulted in a capital loss, which may be deducted solely against capital gains, if any, realized by us in our consolidated federal tax returns. There is a three-year carryback and a five-year carryforward for capital losses under existing federal statutes. For financial reporting purposes, we recorded a valuation allowance against a portion of the potential tax benefit because of uncertainty about our ability to generate future capital gains. Please see Note 14 Income Taxes beginning on page F-50 for further information about our capital loss carryforwards and related valuation allowance.

Pursuant to the sale agreement, we are obligated to indemnify MidAmerican against any breaches of our representations and warranties contained therein. This indemnification obligation, which is capped at approximately $209 million, includes any potential tax liabilities we might have assumed when we acquired Northern Natural from the Enron consolidated group.

On September 30, 2002, DHI sold $90 million in Northern Natural 6.875% senior notes due May 2005 for approximately $96 million, including accrued interest of $2 million. DHI acquired the notes at par value in April 2002 pursuant to a tender offer that it agreed to effect in order to obtain a bondholder consent in connection with the acquisition of Northern Natural. The gain on sale of approximately $4 million is reflected in other income and expense, net on the accompanying 2002 consolidated statements of operations and is net of accrued interest.

U.K. Storage. In the fourth quarter 2001, we completed the purchase of BGSL, a wholly owned subsidiary of BG Group plc. Under the terms of the purchase agreement, we paid approximately £421 million (approximately $595 million at November 28, 2001) for BGSL and its assets. The assets consisted primarily of the Hornsea onshore gas storage facility in the United Kingdom, the Rough offshore natural gas fields in the North Sea and the Easington natural gas processing terminal on the East Yorkshire coast.

BGSL s results of operations are included as a discontinued operation in our consolidated statements of operations, as part of our CRM segment, beginning December 1, 2001. A condensed balance sheet as of the acquisition date is as follows ($ in millions):

Current assets	$ 57
Property, plant and equipment	792
Goodwill	9
Total assets acquired	858
Current liabilities	56
Long-term liabilities	207
Total liabilities assumed	263
Net assets acquired	$ 595

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On September 30, 2002, we sold a subsidiary that owned the Hornsea facility for net cash proceeds of approximately $189 million. There was no gain or loss recognized on this sale. On November 14, 2002, we sold the subsidiaries that owned the Rough offshore natural gas field and the Easington natural gas processing terminal for cash proceeds of approximately $500 million, thereby completing the disposition of all BGSL-related assets. We recognized a pre-tax gain on the sale of Rough of approximately $30 million ($5 million after-tax) in 2002.

Global Liquids. With our decision to exit the international LPG trading and transportation business, we sold our global liquids business in December 2002, which was included in our NGL segment, to Trammo Gas International Inc., a wholly owned subsidiary of Transammonia Inc. We did not receive any cash consideration at close. We have the right to receive contingent payments in the future, which are capped at $8 million. We recorded pre-tax write-downs and accruals totaling $27 million associated with this transaction in 2002, which is reflected in discontinued operations in the NGL segment.

Approximately $12 million of the $27 million charge noted above was our investment in EIOL. We had a 37.5% ownership interest in EIOL valued at $12 million that we accounted for using the equity method. As previously reported, we wrote down our investment in the EIOL project to zero at December 31, 2002 due to our expectation that we would receive no value or cash flows for our current investment in the project. As expected, our exit from the EIOL project was completed in 2003. The remaining 2002 charges associated with this disposition included the write-off of a logistics and accounting computer system not acquired by the purchaser and other related restructuring costs.

Global Communications. In September 2000, we completed the acquisition of Extant, a privately held communications company. Our net investment consisted of $92 million in cash and 1.8 million shares of our Class A common stock. Following the transaction, we established DGC, a new segment that also owned 80% of a limited partnership called DynegyConnect, L.P., to conduct many of the activities previously conducted by Extant. In March 2003, we agreed to acquire the remaining 20% of DynegyConnect effective September 19, 2001 in exchange for $45 million cash and settlement of a lawsuit. Additionally, in the first quarter 2001, we finalized the acquisition of iaxis, a European communications business, and created Dynegy Europe Communications.

DGC executed an agreement to sell 40% of its ownership in an entity that owns a Beijing communications data center. DGC retained a 20% ownership interest, which will be accounted for using the cost method. The sale of the Asian investments resulted in a $2 million pre-tax gain ($3 million after-tax) in the fourth quarter 2002, net of the impact of assets impaired in the second quarter 2002.

During January 2003, we disposed of Dynegy Europe Communications to an affiliate of Klesch & Company, a London-based private equity firm. We recognized an after-tax gain on the sale of approximately $19 million in the first quarter 2003.

During May 2003, we disposed of our U.S. communications network held by DynegyConnect, L.P. to an affiliate of 360networks Corporation. During the second quarter 2003, we recognized an after-tax gain on the sale of approximately $2 million. Approximately $13 million of undiscounted obligations with respect to this business remain following these sales.

U.K. CRM. We substantially completed our exit from the U.K. CRM business during the first quarter 2003. For the year ended December 31, 2003, we recognized an after-tax loss of $21 million, mostly from selling and terminating all our U.K. gas and power positions, as well as administrative expenses, depreciation and

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amortization, shut-down costs and currency translation losses. Collateral postings totaling $98 million were eliminated with the selling/terminations of these positions. We do not expect the U.K. CRM business to have a material impact on our future results.

The following table summarizes information related to our discontinued operations:

	Northern Natural	U.K. Storage	U.K. CRM	Global Liquids	DGC	Total
			(in millions)			
2003						
Revenue	$	$	$ 21	$	$ 5	$ 26
Loss from operations before taxes			(31)	(2)	(26)	(59)
Loss from operations after taxes			(21)	(2)	(21)	(44)
Gain (loss) on sale before taxes	(3)	1			33	31
Gain (loss) on sale after taxes	(2)	1			26	25
2002						
Revenue	$ 201	$ 140	$ 16	$ 784	$ 22	$ 1,163
Income (loss) from operations before taxes (1)	38	34	(115)	(22)	(856)	(921)
Income (loss) from operations after taxes	23	23	(77)	(19)	(541)	(591)
Gain (loss) on sale before taxes	(599)	30		(15)	2	(582)
Gain (loss) on sale after taxes	(561)	5		(10)	3	(563)
2001						
Revenue	$	$ 15	$ 20	$ 890	$ 27	$ 952
Income (loss) from operations before taxes		6	(31)	(2)	(100)	(127)
Income (loss) from operations after taxes		4	(22)	(1)	(63)	(82)

(1) During the second quarter 2002, we reviewed DGC s long-lived assets for impairment in accordance with SFAS No. 144 and determined that future cash flows from DGC s operations were insufficient to recover the carrying value of its long-lived assets. As a result, a pre-tax impairment charge of $611 million was recorded in Impairment and Other Charges and subsequently reclassified to discontinued operations. In addition, during the first quarter 2002 and third quarter 2002, $20 million and $4 million, respectively, of impairment charges were recorded for our discontinued communications business.

Dispositions and Contract Terminations

Pending Sale of Illinois Power. Please see Note 23 Subsequent Event beginning on page F-86 for a discussion of the pending sale to Ameren of our stock in Illinois Power and our 20% interest in the Joppa power generation facility.

Batesville Tolling Arrangement. In December 2003, we reached an agreement with Virginia Electric and Power Company, a subsidiary of Dominion Resources, to terminate a wholesale power tolling contract totaling approximately 110 MWs. Under the terms of the agreement, we paid Virginia Power $34 million to end the arrangement. As a result, we eliminated approximately $63 million in future capacity payments as well as collateral obligations of $12.5 million. We recognized a pre-tax loss of approximately $34 million ($22 million after-tax) in connection with this agreement.

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Kroger Company Settlement. In July 2003, we reached a settlement with Kroger related to four power supply contracts. Under the terms of the settlement agreement, which was approved by the FERC, Kroger paid us approximately $110 million to terminate two of the four power contracts and to restructure at current market prices the remaining two contracts through which we provide electricity to Kroger subsidiary stores in California. We also resolved an outstanding FERC dispute related to contract pricing as part of the settlement,.

The four contracts were derivatives under SFAS No. 133 and were carried at their fair value on the consolidated balance sheets, with changes in fair value recognized in earnings. Our net risk management asset related to these contracts was approximately $140 million at June 30, 2003. Therefore, the $30 million difference between the settlement of $110 million and the carrying value of the net risk management asset was recorded as a pre-tax charge ($19 million after-tax). The two restructured contracts were carried at fair value with changes in fair value recognized in earnings through August 2003, when such contracts were terminated.

Southern Power Tolling Arrangements. In April 2003, we reached an agreement in principle with Southern Power to terminate three power tolling arrangements among Dynegy, Southern Power and our respective affiliates covering an aggregate of 1,100 MWs. Under the terms of the agreement, we paid Southern Power $155 million to terminate these arrangements. The terminations resulted in $89 million of net collateral being returned to us and eliminated our obligation to make $1.7 billion of capacity payments to Southern Power over the next 30 years. The transaction closed in May 2003, and we recognized a pre-tax loss of approximately $133 million ($84 million after-tax).

Hackberry LNG Project. During the first quarter 2003, we entered into an agreement to sell our interest in Hackberry LNG Terminal LLC, the entity we formed in connection with our proposed LNG terminal/gasification project in Hackberry, Louisiana, to Sempra LNG Corp., a subsidiary of San Diego-based Sempra Energy. The transaction closed in April 2003. At closing, we received an initial payment of $20 million and recognized a pre-tax gain of approximately $12 million ($8 million after-tax) on this sale. We retained the right to receive additional contingent payments based upon project development milestones; however, we are currently in the late stages of negotiations to sell our remaining interest in this project. In October 2003, we received a $15 million payment associated with the completion of a project milestone and recognized a pre-tax gain of $15 million ($9 million after-tax).

SouthStar Energy Services. During the first quarter 2003, we completed the sale of our 20% equity investment in SouthStar Energy Services LLC. We received approximately $20 million cash and recognized a pre-tax gain of approximately $1 million ($1 million after-tax). The gain is included in gain on sale of assets in the consolidated statements of operations.

Canadian Assets. In August and November 2002, we sold significant portions of our Canadian crude oil and natural gas marketing businesses to Seminole. The pre-tax loss on these sales was approximately $7 million.

Acquisitions

DNE. In the first quarter 2001, we acquired the DNE power generation facilities. These facilities consist of a combination of baseload, intermediate and peaking facilities aggregating approximately 1,700 MWs. The facilities are approximately 50 miles north of New York City and were acquired for approximately $903 million cash, plus inventory and certain working capital adjustments. In May 2001, two of our subsidiaries completed a sale-leaseback transaction to provide term financing for the DNE facilities. Under the terms of the sale-leaseback transaction, our subsidiaries sold plants and equipment and agreed to lease them back for terms expiring within 34 years, exclusive of renewal options.

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Consideration Paid for Acquisitions. Consideration paid for the 2002 and 2001 business acquisitions was as follows:

	NNG	BGSL	iaxis
		(in millions)	
Cash purchase of stock	$ 1,565	$ 595	$ 40
Liabilities assumed	1,070	263	83
Total consideration	$ 2,635	$ 858	$ 123

Note 4 Restructuring and Impairment Charges

Amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-8.

In 2003, we recorded a goodwill impairment totaling $311 million and a pre-tax asset impairment totaling $193 million relating to our interest in Illinois Power. For further discussion, please see Note 10 Goodwill beginning on page F-38. In addition, during 2003, we recorded a $26 million pre-tax charge related to the impairment of some of our generation investments. For further discussion, please see Note 9 Unconsolidated Investments GEN Investments beginning on page F-35. Also, during 2003, we recorded a $12 million pre-tax charge related to the impairment of our investment in GCF. For further discussion, please see Note 9 Unconsolidated Investments NGL Investments beginning on page F-36.

In 2002, we recorded a goodwill impairment relating to our GEN and CRM segments totaling $814 million. For further discussion, please see Note 10 Goodwill beginning on page F-38.

In 2002, we recorded pre-tax restructuring and impairment charges of $1,129 million relating to various aspects of our operations. The table below provides the amounts of these charges by business area and the caption in which they are included in our consolidated statements of operations:

	Depreciation and Amortization	Impairment and Other Charges	(Earnings) Losses of Unconsolidated	Other	Discontinued Operations	Total Charge

	Expense		Investments			
			(in millions)			
Impairment of communications business	$	$	$	$	$ 635	$ 635
Severance and other restructuring costs	17	140		20	42	219
Impairment of generation investments			144			144
Impairment of technology investments			31		49	80
Impairment of other obsolete assets		50			1	51
	$ 17	$ 190	$ 175	$ 20	$ 727	$ 1,129

Impairment of Communications Business. During 2002, prospects for the communications sector continued to deteriorate as evidenced by an increased number of bankruptcies in the sector, continued devaluation of debt and equity securities, a lack of financing sources and further pricing pressures resulting from challenges faced by major industry participants. As a result of this deterioration, a continuing negative outlook for the industry and our desire to improve our liquidity, we began to take measures to reduce cash losses in the business, including reducing capital spending and lowering operating and administrative expenses.

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(RESTATED)

Our impairment analysis of our communications business, calculated in accordance with the guidelines set forth in SFAS No. 144, indicated future cash flows from DGC s operations were insufficient to recover the carrying value of its long-lived assets. As a result, impairments totaling $306 million ($199 million after-tax) were recorded. As all of these charges relate to our global communications business, they are reported in discontinued operations. In addition, assets related to communications leases were determined to be impaired, resulting in an additional impairment of $329 million ($214 million after-tax), which is also reported in discontinued operations.

Severance and Other Restructuring Costs. In the second quarter 2002, we recognized a $37 million pre-tax ($24 million after-tax) charge for severance benefits from a work force reduction that affected approximately 325 employees. In addition, in October 2002, we announced a restructuring plan designed to improve operational efficiencies and performance across our lines of business. As part of this restructuring, which included a further work force reduction of approximately 780 employees, we recognized a pre-tax charge of $182 million ($118 million after-tax) during the fourth quarter 2002. The total charge of $219 million ($142 million after-tax) is detailed below (in millions):

Cancellation fees and operating leases	$ 61
Severance	115
Asset impairments	15
Change in estimated useful lives of assets	28
	$ 219

In accordance with EITF Issue 94-3, we recognized $61 million in charges ($40 million after-tax) associated with cancellation fees and accruals for the termination of operating leases. These accruals are not discounted.

In addition, we recognized charges of $115 million ($75 million after-tax) for severance benefits for approximately 1,100 employees of various segments and all staffing levels, including our former Chief Executive Officer, former President and former Chief Financial Officer.

Following is a schedule of 2003 and 2002 activity for the liabilities recorded associated with the cancellation fees, operating leases and severance:

	Severance	Cancellation Fees and Operating Leases	Total

		(in millions)	
Balance at December 31, 2001	$	$	$
2002 charge	115	61	176
2002 cash payments	(44)		(44)
Balance at December 31, 2002	$ 71	$ 61	$ 132
2003 adjustments to liability	(8)	4	(4)
2003 cash payments	(40)	(35)	(75)
Balance at December 31, 2003	$ 23	$ 30	$ 53

The adjustment to the accrued liability during 2003 primarily reflects reductions in the severance accrual for employees who will now be retained, as well as for employees of our foreign operations. In addition, we adjusted the liability for operating leases for revised estimates of potential income from subleasing the leased facilities.

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The severance balance at December 31, 2003 primarily relates to severance that has not been paid to our former Chief Executive Officer, former President and former Chief Financial Officer, each of whom has initiated an arbitration proceeding against us related to this severance. Please read Note 17 Commitments and Contingencies Summary of Material Legal Proceedings Severance Arbitrations beginning on page F-62 for further discussion.

Impairment losses of $15 million ($10 million after-tax) were also incurred in accordance with SFAS No. 144 as a result of the corporate restructuring plan for certain technology assets no longer being utilized. The remaining $28 million ($18 million after-tax) of the charge represents accelerated depreciation due to a change in the estimated useful life for leasehold improvements and technology assets related to the abandonment of those assets. This charge was included in depreciation and amortization expense, and $11 million was subsequently reclassified to discontinued operations.

Impairment of generation investments. In conjunction with our review of the carrying value of goodwill in the third quarter 2002 (see Note 10 Goodwill beginning on page F-38 for further discussion), we assessed the carrying value of our generation portfolio on an asset-by-asset basis. The generation portfolio includes wholly-owned generating facilities, which are reflected in property, plant and equipment, as well as investments in partnerships and limited liability companies that own generating facilities, which are reflected in unconsolidated investments. Based on this review, the carrying value associated with the wholly-owned generation facilities was considered realizable. However, some unconsolidated investments were considered impaired, resulting in a pre-tax charge of $144 million, which is reflected in earnings (losses) from unconsolidated investments on the consolidated statements of operations. The diminution in the fair value of these investments was primarily a result of depressed energy prices.

Impairment of technology investments. During the second quarter 2002, we recognized an impairment charge associated with certain technology investments. The $23 million pre-tax ($15 million after-tax) charge was recorded in earnings (losses) from unconsolidated investments, and $4 million of the charge ($3 million after-tax) was subsequently reclassified to discontinued operations. This is in addition to the first quarter 2002 pre-tax charge of $45 million ($30 million after-tax) resulting from unfavorable market conditions, which was recorded in earnings (losses) from unconsolidated investments and subsequently reclassified to discontinued operations.

These investments were re-evaluated at September 30, 2002 based on our inability to sell certain investments for their adjusted carrying values and the continued depressed conditions in the technology sector. Based on this assessment, the remaining carrying value of these investments was written-off, resulting in a pre-tax charge of $12 million ($8 million after-tax), which was recorded in earnings (losses) from unconsolidated investments. The cumulative pre-tax charge related to technology investments for the year ended December 31, 2002 was $80 million ($53 million after-tax), of which $49 million was subsequently reclassified to discontinued operations.

Impairment of other obsolete assets. As a result of our decision to exit the CRM business, our investment in Dynegy*direct* was written off in the third quarter 2002, resulting in a pre-tax charge of $25 million ($16 million after-tax). The charge was recorded in impairment and other charges in the consolidated statements of operations.

In the fourth quarter 2002, we also recognized a $14 million ($9 million after-tax) charge associated with the impairment of a generation turbine, as its fair value calculated in accordance with SFAS No. 144 was less than its carrying value. The charge was recorded in impairment and other charges in the consolidated statements of operations.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

We recognized a pre-tax charge of $12 million ($8 million after-tax) in the second quarter 2002 related to the retirement of partially depreciated information technology equipment and software replaced during the quarter with new system applications and arrangements as well as miscellaneous deposits that are not expected to provide future value. The equipment and software was replaced during the second quarter 2002 with new system applications and arrangements. The charge was recorded in impairment and other charges, and $1 million of the charge ($1 million after-tax) was subsequently reclassified to discontinued operations.

Note 5 Risk Management Activities and Financial Instruments

Our operations are impacted by several factors, some of which may not be mitigated by risk management methods. These risks include, but are not limited to, commodity price, interest rate and foreign exchange rate fluctuations, weather patterns, counterparty credit risks, changes in competition, operational risks, environmental risks and changes in regulations.

We define market risk as changes to our earnings and cash flow resulting from changes in market conditions, including changes in commodity prices, interest rates and currency rates as well as the impact of volatility and market liquidity on such prices. We seek to manage market risk through diversification, controlling position sizes and executing hedging strategies.

Accounting for Derivative Instruments and Hedging Activities

We follow the accounting and disclosure requirements of SFAS No. 133, as amended. On January 1, 2001, we recorded the impact of the adoption of SFAS No. 133 as a cumulative effect adjustment to our consolidated results as follows:

	Net Income	Other Comprehensive Income
	(in millions)	
Adjustment to fair value of derivatives	$ 3	$ 105
Income tax effects	(1)	(44)
Total	$ 2	$ 61

Under SFAS No. 133, all derivative instruments are recognized in the balance sheet at their fair values and changes in fair value are recognized immediately in earnings, unless such instruments qualify, and are designated, as hedges of future cash flows, fair values or net investments in foreign operations or qualify, and are designated as normal purchases and sales. We distinguish between these hedges, which are further described below, as follows:

Cash flow hedges. Under these derivatives, the effective portion of changes in fair value is recorded as a component of accumulated other comprehensive loss until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported immediately as a component of other income and expense, net in the consolidated statements of operations.

Fair value hedges. Under these derivatives, changes in the fair value of the derivative and changes in the fair value of the related asset or liability are recorded in current period earnings.

Net investments in foreign operations. Under these derivatives, the effective portion of changes in the fair value of the derivative is recorded in the foreign currency translation adjustment, a component of accumulated other comprehensive loss. Any ineffective portion is reported immediately as a component of other income and expense, net in the consolidated statements of operations.

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DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Cash flow hedges. We enter into financial derivative instruments that qualify as cash flow hedges. Instruments related to our power generation and natural gas liquids businesses are entered into for purposes of hedging future fuel requirements and sales commitments and locking in future margin. Interest rate swaps are used to convert the floating interest-rate component of some obligations to fixed rates.

During the years ended December 31, 2003, 2002 and 2001, there was no material ineffectiveness from changes in fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness related to the hedge of future cash flows. During the year ended December 31, 2003, we recorded a charge of less than $1 million related to the reclassification of earnings in connection with forecasted transactions that were no longer considered probable of occurring. During the years ended December 31, 2002 and 2001, no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable of occurring.

The balance in cash flow hedging activities, net at December 31, 2003 is expected to be reclassified to future earnings, contemporaneously with the related purchases of fuel, sales of electricity or natural gas liquids and payments of interest, as applicable to each type of hedge. Of this amount, after-tax gains of approximately $2 million are currently estimated to be reclassified into earnings over the 12-month period ending December 31, 2004. The actual amounts that will be reclassified to earnings over this period and beyond could vary materially from this estimated amount as a result of changes in market conditions and other factors.

Fair value hedges. We also enter into derivative instruments that qualify as fair value hedges. We use interest rate swaps to convert a portion of our non-prepayable fixed-rate debt into variable-rate debt. During the years ended December 31, 2003, 2002 and 2001, there was no ineffectiveness from changes in the fair value of hedge positions and no amounts were excluded from the assessment of hedge effectiveness. During the year ended December 31, 2003, we recorded a $6 million gain related to firm commitments that no longer qualified as fair value hedges. During the years ended December 31, 2002 and 2001, no amounts were recognized in relation to firm commitments that no longer qualified as fair value hedges.

Net investment hedges in foreign operations. We have investments in foreign subsidiaries, the net assets of which are exposed to currency exchange-rate volatility. We have used derivative financial instruments, including foreign exchange forward contracts and cross-currency interest rate swaps, to hedge this exposure. As of December 31, 2003, we had no net investment hedges in place. For the years ended December 31, 2002 and 2001, approximately $12 million and $29 million, respectively, of net losses related to these contracts were included in the foreign currency translation adjustment. This amount offsets the cumulative translation gains of the underlying net investments in foreign subsidiaries for the period the derivative financial instruments were outstanding.

During the year ended December 31, 2003, our efforts to exit the U.K. CRM business and the European communications business were substantially completed. As required by SFAS No. 52, Foreign Currency Translation, a significant portion of unrealized gains and losses resulting from translation and financial instruments utilized to hedge currency exposures previously recorded in stockholders equity were recognized in income, resulting in an after-tax loss of approximately $16 million.

DYNEGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(RESTATED)

Accumulated other comprehensive loss. Accumulated other comprehensive loss, net of tax, is included in stockholders equity on the consolidated balance sheets as follows:

	December 31,	
	2003	2002
	(in millions)	
Cash flow hedging activities, net	$ 10	$ 8
Foreign currency translation adjustment	27	3
Minimum pension liability	(57)	(66)
Accumulated other comprehensive loss, net of tax	$ (20)	$ (55)

Notional contract amounts. The absolute notional contract amounts associated with the derivative instruments designated as hedges were as follows:

	December 31,	
	2003	2002
Fair Value Hedge Interest Rate Swaps (in Millions of U.S. Dollars)	$ 25	$ 601
Fixed Interest Rate Received on Swaps (Percent)	5.706	5.616
Cash Flow Hedge Interest Rate Swaps (in Millions of U.S. Dollars)	$ 405	$ 1,566
Fixed Interest Rate Paid on Swaps (Percent)	3.448	2.824
Natural Gas Cash Flow Hedges (Trillion Cubic Feet) (1)	0.073	
Electricity Cash Flow Hedges (Million Megawatt Hours) (1)	3.651	
Fuel Oil Cash Flow Hedges (Million Barrels) (1)	0.825	

(1) As of December 31, 2002, we had not designated any commodity derivative instruments as cash flow or fair value hedges.

Fair Value of Financial Instruments. The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, Disclosures About Fair Value of Financial Instruments. We have determined the estimated fair-value amounts using available market information and selected valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies could have a material effect on the estimated fair-value amounts.

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DYNEGY INC.

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(RESTATED)

The carrying values of current financial assets and liabilities approximate fair values due to the short-term maturities of these instruments. The carrying amounts and fair values of debt are included in Note 12 Debt beginning on page F-41. The carrying amounts and fair values of our other financial instruments were:

	December 31,			
	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Dynegy Inc.				
Series B Preferred Stock (1)	$	$	$ 1,500	$ 365
Series C Convertible Preferred Stock	400	316		
Foreign Currency Risk-Management Contracts			3	3
Dynegy Holdings Inc.				
Subordinated Debentures (2)			200	14
Fair Value Hedge Interest Rate Swap	3	3	73	73
Cash Flow Hedge Interest Rate Swap	(3)	(3)	(16)	(16)
Interest Rate Risk-Management Contracts	(4)	(4)	(74)	(74)
Commodity Cash Flow Hedge Contracts	17	17		
Commodity Risk-Management Contracts	(86)	(86)	(43)	(43)
Illinois Power Company				
Serial Preferred Securities of a Subsidiary	11	10	11	4

(1) Carrying value at December 31, 2002 represents $1,212 million included in Redeemable Preferred Securities, $660 million in additional paid-in capital and $(372) million in accumulated deficit in the consolidated balance sheets.

(2) At December 31, 2003, these securities were classified as Debt on the consolidated balance sheets. Please read Note 2 Accounting Policies Accounting Principles Adopted SFAS No. 150 beginning on page F-20 and Note 12 Debt beginning on page F-41.

The fair value of our Preferred Securities of a Subsidiary Trust at December 31, 2002 were based on quoted market prices by financial institutions that actively trade these debt securities. The fair value of the Series B Preferred Stock at December 31, 2002 reflects management s then-current estimate of the realizable value of such securities based on an estimate of our enterprise value. This enterprise value estimate reflected information derived from the debt and equity markets and, as a result, was highly sensitive to the market prices at which our public debt and equity securities traded. The fair value of the Series C convertible preferred stock at December 31, 2003 is based on an estimate provided by an external financial institution. The estimate reflects debt and equity market information for comparable securities and also incorporates the original lock-up period of the security. The fair value stated above is the mid-point of the valuation range of $287 million to $344 million. The fair value of interest rate, foreign currency and commodity risk-management contracts were based upon the estimated consideration that would be received to terminate those contracts in a gain position and the estimated cost that would be incurred to terminate those contracts in a loss position.

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(RESTATED)

Note 6 Cash Flow Information

Following are supplemental disclosures of cash flow and non-cash investing and financing information:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Interest paid (net of amount capitalized)	$ 428	$ 323	$ 248
Taxes paid (net of refunds)	$ (116)	$ 12	$ 79
Detail of businesses acquired:			
Current assets and other	$	$ 144	$ 62
Fair value of non-current assets		2,491	903
Liabilities assumed, including deferred taxes		(1,070)	(346)
Cash balance acquired		(44)	(16)
Cash paid, net of cash acquired	$	$ 1,521	$ 603
Other non-cash investing and financing activity:			
Series B Exchange	$ 1,224	$	$
Implied dividend on Series B Preferred Stock	(203)	(330)	(42)
Addition of a capital lease	66	170	
Sale of West Texas LPG Pipeline Limited Partnership		45	

The businesses acquired included: Northern Natural (2002); BGSL (2001); and iaxis (2001). Please read Note 3 Discontinued Operations, Dispositions, Contract Terminations and Acquisitions Discontinued Operations beginning on page F-21 for more information regarding these acquisitions. The $1,521 million paid to acquire Northern Natural includes $1,501 million paid in 2001, which is included in investments in unconsolidated affiliates in the consolidated statements of cash flows for the year ended December 31, 2001.

Note 7 Inventory

A summary of our inventories is as follows:

	December 31,	
	2003	2002
	(in millions)	
Natural gas in storage	$ 77	$ 49
Natural gas liquids	40	46
Coal	48	49
Crude oil	16	10
Materials and supplies	98	82
	$ 279	$ 236

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(RESTATED)

Note 8 Property, Plant and Equipment

Amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-8.

A summary of our property, plant and equipment is as follows:

	December 31,	
	2003	2002
	(in millions)	
Generation assets	$ 5,745	$ 5,428
Natural gas liquids assets		
Natural gas processing	1,048	992
Fractionation	234	221
Liquids marketing	35	33
Natural gas gathering and transmission	160	176
Terminals and storage	248	254
Barges	29	29
Regulated energy delivery assets	2,156	2,053
Customer risk management assets	4	14
IT systems and other	208	459
	9,867	9,659
Accumulated depreciation	(1,664)	(1,201)
	$ 8,203	$ 8,458

Interest capitalized related to costs of projects in process of development totaled $12 million, $16 million and $20 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Note 9 Unconsolidated Investments

Our unconsolidated investments consist primarily of investments in affiliates that we do not control, but where we have significant influence over operations. These investments are accounted for by the equity method of accounting. Our share of net income from these affiliates is reflected in the consolidated statements of operations as earnings (losses) from unconsolidated investments. Our principal equity method investments consist of entities that operate generation and natural gas liquids assets. We entered into these ventures principally to share risk and leverage existing commercial relationships. These ventures maintain independent capital structures and have financed their operations either on a non-recourse basis to us or through their ongoing commercial activities. We hold investments in joint ventures in which ChevronTexaco or its affiliates are investors. For additional information about these investments, please read Note 13 Related Party Transactions beginning on page F-48.

A summary of our unconsolidated investments is as follows:

	December 31,	
	2003	**2002**
	(in millions)	
Equity affiliates:		
GEN investments	$ 518	$ 542
NGL investments	82	102
CRM investments		4
Total equity affiliates	600	648
Other affiliates, at cost	12	20
Total unconsolidated investments	$ 612	$ 668

DYNEGY INC.

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(RESTATED)

Cash distributions received from our equity investments during 2003, 2002 and 2001 were $158 million, $91 million and $100 million, respectively. Our investment balances include unamortized purchase price differences of $73 million and $65 million at December 31, 2003 and 2002, respectively. The unamortized purchase price differences represent the excess of our purchase price over our share of the investee s book value at the time of acquisition. Undistributed earnings from our equity investments included in accumulated deficit at December 31, 2003 and 2002 totaled $161 million.

GEN Investments. Generation investments include ownership interests in nine joint ventures that own fossil fuel electric generation facilities, as well as a limited number of international ventures. Our ownership is 50% in the majority of these ventures. Our aggregate net investment of $518 million at December 31, 2003 represents approximately 2,300 MWs of net generating capacity. Our most significant investment in generating capacity is our interest in West Coast Power, representing approximately 1,200 MWs of net generating capacity in California. Our net investment in West Coast Power totaled approximately $291 million and $287 million at December 31, 2003 and December 31, 2002, respectively. West Coast Power provided equity earnings of approximately $117 million, $17 million and $162 million in the years ended December 31, 2003, 2002 and 2001, respectively. West Coast Power earnings for 2003 include a $20 million charge representing our share of a goodwill impairment. West Coast Power earnings for 2002 include an impairment charge of $33 million to write down our investment to fair value, as well as a $50 million charge representing our share of a bad debt allowance. A significant amount of West Coast Power s earnings relate to the CDWR contract, which expires at the end of 2004.

Summarized financial information for West Coast Power, and our equity share thereof, was:

	December 31,					
	2003		2002		2001	
	Total	Equity Share	Total	Equity Share	Total	Equity Share
	(in millions)					
Current assets	$ 257	$ 129	$ 255	$ 128	$ 401	$ 201
Non-current assets	454	227	532	266	659	330
Current liabilities	55	28	112	56	138	69
Non-current liabilities	8	4	34	17	269	135
Revenues	696	348	585	293	1,562	781
Operating income	231	116	48	24	345	173
Net income	233	117	34	17	326	162

In the fourth quarter 2003, we evaluated our domestic and international interests in several power generation entities. We conducted this evaluation, which was required by GAAP, because of a surplus of both international and domestic investments being actively marketed for sale and a continued, sustained downturn in the independent power producer market. Through our evaluation, we determined that several of these equity investments experienced circumstances and events that indicated that the book value of our investment was no longer recoverable and that such decline in value was other than temporary. For some of our investments, we have entered into active discussions with either the owner of the entity or a third party, who, in some cases, has conducted extensive due diligence on the investment to determine an appropriate bid price. We believe that a bid price, or an external valuation, is the best determinant of fair value for these investments, if available. For other investments, we prepared internal valuation models to determine the fair value. After comparing the fair values of each of our investments to their book value, we recorded a pre-tax impairment charge of $26 million ($16 million after-tax) and included this charge in earnings (losses) from unconsolidated investments. The ultimate sale of these investments may result in additional charges.

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During the first quarter 2004, we sold our interest in our Jamaica project, an international facility with aggregate net generating capacity of 13 MWs (our 17.55% share). Net proceeds associated with the sale were approximately $5.5 million, and we did not recognize a gain or loss on the sale. Also during the first quarter 2004, we entered into agreements to sell our interests in Oyster Creek and Michigan Power. Closing of the transactions, which are subject to regulatory approval and other closing conditions, is expected in the second quarter 2004.

In August and September 2003, we sold our interests in the Frontier, Paris and Ferndale domestic projects located in Texas and Washington (aggregate net generating capacity of approximately 130 MWs) and in two international projects located in Honduras and Pakistan (aggregate net generating capacity of approximately 110 MWs). Net proceeds associated with these sales were approximately $25 million. We recognized a $1 million after-tax loss on the transactions during 2003.

On November 22, 2002, a petition was filed in the United States Bankruptcy Court for the District of Minnesota by several former officers of NRG Energy, the parent company of the partner and operator in two of our joint ventures (including West Coast Power), to put NRG Energy into bankruptcy. This proceeding was settled and the involuntary bankruptcy was dismissed in early May 2003. NRG Energy and certain of its affiliates subsequently made voluntary Chapter 11 filings in the United States Bankruptcy Court for the Southern District of New York, together with a filing of a plan of reorganization. In July 2003, we filed proofs of claim against NRG Energy and certain of its affiliates, and the Bankruptcy Court confirmed NRG Energy s plan of reorganization in November 2003. According to a press release issued by NRG Energy, it emerged from bankruptcy in December 2003, although it has yet to address our proofs of claim. We cannot predict with any degree of certainty the effects of this plan or NRG Energy s reorganization on the operations of the joint ventures.

In addition to the charges related to our investment in West Coast Power described above, equity earnings during 2002 were negatively impacted by a pre-tax impairment of $111 million (net of the $33 million West Coast Power impairment) in multiple equity investments based on a fair value assessment, as further discussed in Note 4 Restructuring and Impairment Charges beginning on page F-26.

NGL Investments. At December 31, 2003, natural gas liquids investments included a 22.9% ownership interest in Venice Energy Services Company, L.L.C. (VESCO), a venture that operates a natural gas liquids processing, extraction, fractionation and storage facility in the Gulf Coast region as well as a 38.75% ownership interest in GCF, a venture that fractionates natural gas liquids on the Gulf Coast. In August 2002, we sold our investment in WTLPS to ChevronTexaco. Please read Note 13 Related Party Transactions beginning on page F-48 for further discussion of this transaction.

During the fourth quarter 2003, we determined that the fair value of our minority interest in GCF, based on bid prices received for a possible sale of the investment, was lower than the book value. As such, we recorded a pre-tax impairment charge in the fourth quarter of 2003 of $12 million ($8 million after-tax) and included this charge in earnings (losses) from unconsolidated investments.

CRM Investments. During the first quarter 2003, we sold substantially all of the operations of Nicor Energy, a joint venture with Nicor Inc., and we are in the process of completing the liquidation of the company. As of December 31, 2003, we had settled all payments relating to this joint venture and no longer maintain a purchase agreement with Nicor Energy.

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(RESTATED)

Summarized aggregate financial information for unconsolidated equity investments, exclusive of the West Coast Power information previously disclosed, and our equity share thereof was:

	December 31,					
	2003		2002		2001	
	Total	Equity Share	Total	Equity Share	Total	Equity Share
	(in millions)					
Current assets	$ 271	$ 109	$ 504	$ 175	$ 555	$ 189
Non-current assets	1,404	605	1,441	607	1,724	652
Current liabilities	182	73	375	144	401	146
Non-current liabilities	649	301	720	330	1,021	377
Revenues	1,501	542	2,762	990	2,438	767
Operating income	234	90	336	105	304	95
Net income	154	53	239	70	218	61

Earnings from unconsolidated investments of $124 million for the year ended December 31, 2003 includes the $53 million above and $117 million from West Coast Power, offset by $45 million in impairments of investments and a $1 million loss on the sale of an investment. Losses from unconsolidated investments of $80 million for the year ended December 31, 2002 consist primarily of the $70 million above and $17 million from West Coast Power, offset by impairments of generation and technology investments of $144 million and $31 million, respectively (see Note 4 Restructuring and Impairment Charges Impairment of generation investments and Note 4 Restructuring and Impairment Charges Impairment of technology investments, both beginning on page F-28). Earnings from unconsolidated investments of $191 million for the year ended December 31, 2001 consist primarily of the $61 million above and $162 million from West Coast Power, offset by a $19 million pre-tax loss on a technology investment due to impairment.

Other Investments. In addition to these equity investments, we hold interests in companies for which we do not have significant influence over the operations. These investments are accounted for by the cost method. Such investments totaled $12 million and $20 million at December 31, 2003 and 2002, respectively. We also owned securities that had a readily determinable fair market value and were considered available-for-sale. During 2001, we recognized a $19 million pre-tax loss on a technology investment due to impairments that were determined by management to be other-than-temporary. During 2002, we wrote down the remaining values of our available-for-sale securities. For further discussion, please see Note 4 Restructuring and Impairment Charges beginning on page F-26. The market value of these investments at December 31, 2003 and 2002 was estimated to be zero.

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Note 10 Goodwill

Amounts in this footnote have been restated. For further information, please see the Explanatory Note beginning on page F-8.

The changes in the carrying amount of goodwill for each of our reporting units for the years ended December 31, 2003 and 2002 were as follows:

	GEN	NGL	REG	CRM	Other	Total
			(in millions)			
Balances as of January 1, 2002	$ 489	$ 16	$ 311	$ 358	$ 234	$ 1,408
Cumulative effect of change in accounting principle					(234)	(234)
Goodwill acquired during the period			887			887
Purchase price adjustments			(28)	(33)		(61)
Goodwill impaired during the period	(489)			(325)		(814)
Sale of Canadian Crude business		(1)				(1)
Sale of Northern Natural			(859)			(859)
Balances as of December 31, 2002		15	311			326
Goodwill impaired during the period			(311)			(311)
Balances as of December 31, 2003	$	$ 15	$	$	$	$ 15

During 2003, the value of goodwill associated with Illinois Power was determined to be impaired, resulting in our recognizing a charge of $311 million. Additionally, Illinois Power s other assets were determined to be impaired, resulting in our recognizing a pre-tax charge of $193 million. In determining the impairment amount, the fair value of Illinois Power was determined based on the sales price allocation assigned to Illinois Power from the announced sale of Illinois Power and our Joppa investment in February 2004, as further described in Note 23 Subsequent Event beginning on page F-86. The impairment charges are reflected in the consolidated statements of operations in Goodwill impairment and Impairment and other charges.

Significant components of the changes in goodwill during 2002 included the following:

We adopted SFAS No. 142 effective January 1, 2002, and, accordingly, tested for impairment all amounts recorded as goodwill. We determined that goodwill associated with our former DGC reporting segment was impaired and we therefore recognized a charge of $234 million for this impairment. The fair value of this reporting segment was estimated using the expected discounted future cash flows. The value was negatively impacted by continued weakness in the communications and broadband markets. The impairment charge is reflected in the consolidated statements of operations as a cumulative effect of change in accounting principle.

During 2002, the value of goodwill associated with our former WEN segment was determined to be impaired, resulting in our recognizing a charge of $814 million. The fair values of the respective components of this segment were estimated utilizing the expected discounted future cash flows. The primary factors leading to this impairment were: (1) the reduction in near-term power prices; (2) an increase in the rate of return required for investors to enter the energy merchant sector; and (3) our decision to exit third-party risk management aspects of the marketing and trading business. The impairment charge is reflected in the consolidated statements of operations as a goodwill impairment.

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Also in 2002, $887 million of goodwill associated with the acquisition of Northern Natural was recorded in the REG segment and subsequently removed when Northern Natural was sold. See Note 3 Discontinued Operations, Dispositions, Contract Terminations and Acquisitions Discontinued Operations Northern Natural beginning on page F-22 for additional discussion of the sale of Northern Natural.

All charges related to goodwill during 2003 are the same on a pre-tax or an after-tax basis. Of the $814 million goodwill impairment recognized in 2002, $579 million related to goodwill for which there was no tax basis, and thus that portion of the impairment was the same on a pre-tax or an after-tax basis. The remaining impairment of $235 million was $148 million on an after-tax basis.

The following table shows what our net income and earnings per share would have been in 2001 if goodwill had not been amortized during those periods, compared to the net loss and earnings (loss) per share we recorded for 2003 and 2002:

	2003	2002	2001
		(in millions, except per share data)	
Reported net income (loss)	$ (667)	$ (2,578)	$ 399
Add back: Goodwill amortization			42
Adjusted net income (loss)	$ (667)	$ (2,578)	$ 441
Less: preferred stock dividends (gain)	(1,013)	330	42
Net income (loss) available to common stockholders	$ 346	$ (2,908)	$ 399
Basic earnings (loss) per share:			
Reported net income (loss)	$ 0.93	$ (7.95)	$ 1.10
Goodwill amortization			0.13
Adjusted net income (loss)	$ 0.93	$ (7.95)	$ 1.23
Diluted earnings (loss) per share:			
Reported net income (loss)	$ 0.84	$ (7.95)	$ 1.05
Goodwill amortization			0.12
Adjusted net income (loss)	$ 0.84	$ (7.95)	$ 1.17

Note 11 Refinancing and Restructuring Transactions

During 2003, we completed a series of transactions that significantly altered our outstanding debt balances. The following summarizes the most significant of those transactions.

Credit Facility Restructuring. On April 2, 2003, DHI entered into a $1.66 billion credit facility, consisting of: (i) a $1.1 billion DHI secured revolving credit facility; (ii) a $200 million DHI secured term loan (Term A Loan); and (iii) a $360 million DHI secured term loan (Term B Loan). The credit facility replaced, and preserved the commitment of each lender under, DHI s former $900 million and $400 million revolving credit facilities, which had maturity dates of April 28, 2003 and May 27, 2003, respectively, and Dynegy s $360 million DGC secured debt, which had a maturity date of December 15, 2005. For further discussion of the credit facility, please see Note 12 Debt DHI Credit Facility beginning on page F-42. We incurred debt issuance costs aggregating approximately $41 million in connection with the new facility. Such amounts have been capitalized and are amortized over the term of the credit facility and term loans.

DYNEGY INC.

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(RESTATED)

Refinancing. In August 2003, we consummated a series of refinancing transactions, which we refer to collectively as the Refinancing. In connection with the Refinancing, DHI issued $1.45 billion of second priority senior secured notes in a private placement transaction pursuant to Rule 4(2) of the Securities Act of 1933 and completed a cash tender offer and related consent solicitation pursuant to which it purchased: approximately (i) $282 million in principal amount of its $300 million 8.125% Senior Notes due 2005; (ii) virtually all of its $150 million 6¾% Senior Notes due 2005; and (iii) $177 million in principal amount of its $200 million 7.450% Senior Notes due 2006. We paid approximately $5 million above par value of the notes in connection with this purchase, and we paid a consent fee in connection with the related consent solicitation to eliminate several of the restrictive covenants and certain other provisions previously contained in the indentures governing these notes.

Also in connection with the Refinancing, we issued $225 million of convertible subordinated debentures in a private placement transaction pursuant to Rule 4(2) of the Securities Act of 1933.

We used the net proceeds from the Refinancing, along with cash on hand, to make the $225 million cash payment required under the Series B Exchange, as described below, and to prepay or repurchase indebtedness including the Term A loan, $165 million of the Term B loan, $609 million of DHI s outstanding senior notes in the tender offer described above and $696 million of debt outstanding under the Black Thunder secured financing.

The prepayment of the debt above resulted in accelerated charges during 2003 of approximately $20 million, pre-tax, of unamortized financing costs and the settlement value of the associated interest rate hedge instruments. We incurred debt issuance costs aggregating approximately $60 million in connection with the Refinancing. Such amounts have been capitalized and are amortized over the term of the notes issued in connection with the Refinancing.

For further discussion of the second priority senior secured notes and the convertible subordinated debentures, please see Note 12 Debt DHI Second Priority Senior Secured Notes beginning on page F-44 and Note 12 Debt Convertible Subordinated Debentures beginning on page F-47.

Series B Exchange. Also in August 2003, we restructured the $1.5 billion in Series B Preferred Stock previously held by a subsidiary of ChevronTexaco. Pursuant to the restructuring, which we refer to as the Series B Exchange, this ChevronTexaco subsidiary exchanged its Series B Preferred Stock for: (i) a $225 million cash payment; (ii) $225 million principal amount of our Junior Unsecured Subordinated Notes due 2016, which we refer to as the Junior Notes; and (iii) 8 million shares of our Series C Mandatorily Redeemable Convertible Preferred Stock due 2033 (liquidation preference of $50 per share), which we refer to as the Series C convertible preferred stock.

For further discussion of the Junior Notes and the Series C convertible preferred stock, please see Note 12 Debt Junior Unsecured Subordinated Notes beginning on page F-47 and Note 15 Redeemable Preferred Securities Series C Convertible Preferred Stock beginning on page F-53.

Follow-on Notes Offering. In October 2003, DHI consummated a follow-on offering, which we refer to as the follow-on notes offering, of $300 million aggregate principal amount of additional second priority senior secured notes in a private placement transaction pursuant to Section 4(2) of the Securities Act of 1933. The net proceeds from the follow-on notes offering, along with cash on hand, were utilized to prepay the $194 million outstanding under our Term B Loan and retire the $170 million capital lease obligation associated with the CoGen Lyondell generation facility. We incurred debt issuance costs aggregating approximately $3 million in connection with the follow-on notes offering. Such amounts have been capitalized and will be amortized over the term of the notes issued in connection with the follow-on notes offering.

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Note 12 Debt

Notes payable and long-term debt consisted of the following:

	December 31,			
	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Dynegy Holdings Inc.				
Revolving Credit Facilities	$	$	$ 128	$ 128
Senior Notes, 6.75% due 2005			150	54
Senior Notes, 8.125% due 2005	18	18	300	114
Senior Notes, 7.45% due 2006	22	24	206	70
Senior Notes, 6.875% due 2011	519	455	522	158
Senior Notes, 8.75% due 2012	500	501	500	170
Senior Debentures, 7.125% due 2018	179	147	190	47
Senior Debentures, 7.625% due 2026	181	147	198	46
Second Priority Senior Secured Notes, floating rate due 2008	225	225		
Second Priority Senior Secured Notes, 9.875% due 2010	625	705		
Second Priority Senior Secured Notes, 10.125% due 2013	900	1,035		
Subordinated Debentures payable to affiliates, 8.316%, due 2027 (1)	200	164		
ABG Gas Supply Credit Agreement, due through 2006				