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	$(1,349)	$486
Pro forma adjustments to reflect retroactive adoption of SFAS No. 143	(6)	(5)
Pro forma income (loss) from continuing operations	$(1,355)	$481
Income (loss) before cumulative effect of change in accounting principles, as reported	$(2,503)	$404
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	$(2,509)	$399
Net income (loss), as reported	$(2,737)	$406
Pro forma adjustments to reflect retroactive adoption of SFAS No. 143	(4)	(3)
Pro forma net income (loss)	$(2,741)	$403

	2002		2001	
	As Reported	Pro Forma	As Reported	Pro Forma
Basic earnings (loss) per share				
Income (loss) from continuing operations	$(4.59)	$(4.60)	$ 1.37	$ 1.36
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	$(8.38)	$(8.39)	$ 1.12	$ 1.11

	2002		2001	
	As Reported	Pro Forma	As Reported	Pro Forma
Diluted earnings (loss) per share				
Income (loss) from continuing operations	$(4.59)	$(4.60)	$ 1.31	$ 1.30
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	$(8.38)	$(8.39)	$ 1.07	$ 1.06

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

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-33, 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 $897 million goodwill impairment in 2002 related to the CRM and GEN segments and a $242 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 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.

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.

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	$(453)	$(2,737)	$ 406
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)	$(504)	$(2,813)	$ 348
Earnings (loss) per share:			
Basic—as reported	$1.50	$ (8.38)	$1.12
Basic—pro forma	$1.36	$ (8.59)	$0.94
Diluted—as reported	$1.35	$ (8.38)	$1.07
Diluted—pro forma	$1.23	$ (8.59)	$0.90

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.

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-68 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-10.

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-14.

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 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-35 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 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-41 and Note 15—Redeemable Preferred Securities—Subordinated Debentures beginning on page F-49. 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-35.

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-12.

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.

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-45 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

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 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-77 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.

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.

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

In 2003, we recorded a goodwill impairment relating to our interest in Illinois Power totaling $242 million. For further discussion, please see Note 10—Goodwill beginning on page F-33. 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-30. 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-31.

In 2002, we recorded a goodwill impairment relating to our GEN and CRM segments totaling $897 million. For further discussion, please see Note 10—Goodwill beginning on page F-33.

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 Expense	Impairment and Other Charges	(Earnings) Losses of Unconsolidated Investments	Other	Discontinued Operations	Total Charge
			(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.

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.

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-56 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-33 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.

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.

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.

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	December 31, 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	December 31, 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.

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-36. The carrying amounts and fair values of our other financial instruments were:

	December 31, 2003		December 31, 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-16 and Note 12—Debt beginning on page F-36.

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.

Note 5—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-18 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	December 31, 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

Note 8—Property, Plant and Equipment

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

	December 31, 2003	December 31, 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	(1,471)	(1,201)
	$ 8,396	$ 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-43.

A summary of our unconsolidated investments is as follows:

	December 31, 2003	December 31, 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

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.

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-22.

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-43 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.

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-24). 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-22. The market value of these investments at December 31, 2003 and 2002 was estimated to be zero.

Note 10—Goodwill

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	$ 549	$ 16	$ 381	$ 381	$ 234	$1,561
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	(549)	—	—	(348)	—	(897)
Sale of Canadian Crude business	—	(1)	—	—	—	(1)
Sale of Northern Natural	—	—	(859)	—	—	(859)
Balances as of December 31, 2002	—	15	381	—	—	396
Goodwill impaired during the period	—	—	(242)	—	—	(242)
Balances as of December 31, 2003	$ —	$ 15	$ 139	$ —	$ —	$ 154

During 2003, the value of goodwill associated with Illinois Power was determined to be impaired, resulting in our recognizing a charge of $242 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-77. The impairment charge is reflected in the consolidated statements of operations as a goodwill impairment.

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 $897 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.

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-18 for additional discussion of the sale of Northern Natural.

All charges related to goodwill during 2003 and 2002 are the same on a pre-tax or 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)	$ (453)	$(2,737)	$ 406
Add back: Goodwill amortization	—	—	46
Adjusted net income (loss)	$ (453)	$(2,737)	$ 452
Less: preferred stock dividends (gain)	(1,013)	330	42
Net income (loss) available to common stockholders	$ 560	$(3,067)	$ 410
Basic earnings (loss) per share:			
Reported net income (loss)	$ 1.50	$ (8.38)	$1.12
Goodwill amortization	—	—	.14
Adjusted net income (loss)	$ 1.50	$ (8.38)	$1.26
Diluted earnings (loss) per share:			
Reported net income (loss)	$ 1.35	$ (8.38)	$1.07
Goodwill amortization	—	—	.14
Adjusted net income (loss)	$ 1.35	$ (8.38)	$1.21

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-37. 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.

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-39 and Note 12—Debt—Convertible Subordinated Debentures beginning on page F-42.

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-42 and Note 15—Redeemable Preferred Securities—Series C Convertible Preferred Stock beginning on page F-48.

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.

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	185	185	259	252
Generation Facility Debt, due 2007	184	184	184	184
Generation Facility Capital Lease	—	—	165	165
Black Thunder Secured Financing	—	—	758	758
Renaissance and Rolling Hills Credit Facility, due 2003	—	—	200	200
Illinova				
Senior Notes, 7.125% due 2004	95	96	100	43
Illinois Power				
Mortgage Bonds, 6.5% due 2003	—	—	100	97
Mortgage Bonds, 6.0% due 2003	—	—	90	87
Mortgage Bonds, 6.75% due 2005	70	72	70	66
Mortgage Bonds, 7.5% due 2009	250	276	250	215
Mortgage Bonds, 11.5% due 2010	550	660	400	388
Mortgage Bonds, 7.5% due 2025	66	67	66	52
Transitional Funding Trust Notes payable to affiliates, 5.34% due through 2003	—	—	30	30
Transitional Funding Trust Notes payable to affiliates, 5.38% due through 2005	118	122	175	178
Transitional Funding Trust Notes payable to affiliates, 5.54% due through 2007	175	183	175	182
Transitional Funding Trust Notes payable to affiliates, 5.65% due through 2008	139	149	139	153
Floating Rate Pollution Control Revenue Refunding Bonds, due 2017	75	75	75	75
Adjustable Rate Pollution Control Revenue Refunding Bonds, due 2028	112	112	112	112
Adjustable Rate Pollution Control Revenue Refunding Bonds, due 2032	150	150	150	150
Pollution Control Revenue Refunding Bonds, 5.4% - 7.4%, due 2024 through 2028	179	181	179	177
Tilton Capital Lease	71	71	—	—
Term Loan, due 2003	—	—	100	100
Dynegy Inc.				
Convertible Subordinated Debentures, 4.75% due 2023	225	316	—	—
Junior Unsecured Subordinated Notes payable to affiliates, 9% - 13.75% due 2016	223	223	—	—
DGC Secured Debt (2)	—	—	360	360
	6,236		6,331	
Unamortized premium (discount) on debt, net	(12)		(16)	
	6,224		6,315	
Less: Amounts due within one year	331		861	
Total Long-Term Debt	$5,893		$5,454	

(1) At December 31, 2002, these securities, which were formerly known as the Company Obligated Preferred Securities of a Subsidiary Trust, were classified as Redeemable Preferred Securities on the Consolidated Balance Sheets. See Note 2—Accounting Policies—Accounting Principles Adopted—SFAS No. 150 beginning on page F-16.

(2) As described in Note 11—Refinancing and Restructuring Transactions—Credit Facility Restructuring beginning on page F-34, the DGC Secured Debt was replaced by DHI's Term B Loan as part of the April 2003 new credit facility, which was subsequently repaid in full during 2003.

Aggregate maturities of the principal amounts of all long-term indebtedness are as follows:

	Total	2004	2005	2006	2007	2008	Thereafter
				(in millions)			
Dynegy Holdings Inc.	$3,744	$ 79	$102	$ 44	$184	$225	$3,110
Illinova	95	95	—	—	—	—	—
Illinois Power (1)	1,937	157	156	86	86	86	1,366
Dynegy Inc.	448	—	—	—	—	—	448
Total	$6,224	$331	$258	$130	$270	$311	$4,924

(1) 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. Please see "Tilton Capital Lease" beginning on page F-41 for a discussion of the delivery of our notice of intent to exercise our option to purchase the leased turbines upon the expiration of the lease in September 2004, with respect to which an $81 million payment is due.

DHI Credit Facility. During the year ended December 31, 2003, we reduced our exposure under our revolving credit facilities by $812 million. During the period from December 31, 2003 through February 23, 2004, our outstanding letters of credit under these revolving credit facilities increased by $34 million.

As discussed in Note 11—Refinancing and Restructuring Transactions—Credit Facility Restructuring beginning on page F-34, on April 2, 2003, DHI entered into a $1.66 billion credit facility consisting of a $1.1 billion secured revolving credit facility, which matures on February 15, 2005, and two secured term loans. We repaid the secured term loans using the proceeds from our August and October 2003 debt offerings, together with cash on hand. We currently have no borrowings under the credit facility, with letters of credit issued of $222 million at February 23, 2004.

The amended credit facility provides funding for general corporate purposes and is available for the issuance of letters of credit. Borrowings under the credit facility bear interest, at our option, at (i) a base rate plus 3.75% per annum or (ii) LIBOR plus 4.75% per annum. A letter of credit fee is payable on the undrawn amount of each letter of credit outstanding at a percentage per annum equal to 4.75% of such undrawn amount. A 0.15% fronting fee is incurred upon the issuance of letters of credit. An unused commitment fee of 0.50% per annum is payable on the unused portion of the revolving facility. We incur additional fees for amending existing letters of credit.

We are required to prepay or cash collateralize outstanding borrowings under our amended credit facility with: (i) all net cash proceeds from non-ordinary course asset sales, subject to certain exceptions, subject to our prior obligation to use a portion of such proceeds to prepay outstanding Junior Notes; (ii) half of the net cash proceeds from issuances of equity, subordinated debt or additional second lien debt, except that we may use up to $250 million of equity issuance proceeds to make mandatory prepayments on the Junior Notes, so long as we reduce permanently or cash collateralize the commitments under the revolving credit facility according to a specified formula; (iii) all net cash proceeds from the issuance of senior debt; and (iv) half of extraordinary receipts (as defined in the amended credit facility).

We are also required to prepay or cash collateralize an amount of such outstanding borrowings calculated according to a specified formula in the event we pay cash dividends on our Series C convertible preferred stock or repurchase DHI senior notes that mature on or after 2007, provided we have $500 million of liquidity after such payment or repurchase. We made the first semi-annual dividend payment on the Series C convertible preferred stock of $11 million on February 11, 2004, as a result of which capacity under our revolving credit facility was reduced by $11 million.

The amended credit facility generally prohibits us and our subsidiaries, including DHI but excluding Illinois Power, from pre-paying, redeeming or repurchasing outstanding debt or preferred stock, except that we may, among other things:

- pay cash dividends on our Series C convertible preferred stock if, among other things, we make a voluntary prepayment of the credit facility and we have $500 million of liquidity after giving effect to such payment;
- prepay, repurchase or redeem, with the net cash proceeds of extraordinary receipts or issuances of equity or subordinated debt, or cash on hand, all of DHI's remaining outstanding 2005-2006 senior notes, and, if we have $500 million of liquidity for 10 days prior to and as of the date of such prepayment, the ABG Gas Supply credit agreement and the generation facility debt; and
- repurchase up to $100 million of DHI senior notes that mature on or after 2007 so long as we have $500 million of liquidity for 10 days prior to and as of the date of such repurchase and the credit facility is prepaid in connection with such repurchase according to a formula; provided that up to $300 million of such notes (including any amount repurchased under the foregoing clause) may be repurchased without a concurrent prepayment under the credit facility with the net cash proceeds of extraordinary receipts or issuances of equity or subordinated debt.

Under the amended credit facility, we and our subsidiaries, including DHI but excluding Illinois Power and DGC, are prohibited from permitting our Secured Debt/EBITDA ratio (in each case as defined in the amended credit facility) to be greater than 9.0:1.0 for the measurement period ending December 31, 2003, with the ratios decreasing quarterly until the measurement period ending December 31, 2004, at which point the ratio can not exceed 6.7:1.0.

The definition of EBITDA in the amended credit facility specifically excludes, among other items: (i) Discontinued Business Operations, as defined therein (including third-party marketing and trading, communications and tolling arrangements); (ii) certain amounts paid, incurred or reserved in connection with any litigation disclosed under the schedules to the amended credit facility; (iii) extraordinary gains or losses; (iv) any impairment, abandonment, restructuring or similar non-cash expenses; (v) interest expense; (vi) gains/losses on extinguishment of debt; and (vii) turbine cancellation payments up to $50 million in the aggregate.

Amendments to DHI Credit Facility. In July and October 2003, in conjunction with the Refinancing and the Series B Exchange, we entered into the third and fourth amendments, respectively, to DHI's credit facility to, among other things, permit the consummation of the then-proposed transactions, which included repaying the Term A Loan and the Term B Loan. The third amendment became effective in August 2003, upon the closing of the Refinancing, and the fourth amendment became effective in October 2003, immediately prior to the closing of the follow-on notes offering.

DHI Senior Notes. In July 2002, DHI repaid its $200 million 6.875% senior notes. In February 2002, DHI issued $500 million of 8.75% senior notes due 2012. Interest on the notes is due on February 15 and August 15 of each year, beginning August 15, 2002. The notes are unsecured and are not subject to a sinking fund.