DYNEGY INC /IL/
Form 10-Q
May 10, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 2006

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______

Commission file number: 1-15659

DYNEGY INC.

(Exact name of registrant as specified in its charter)

Illinois	**74-2928353**
(State of incorporation)	**(I.R.S. Employer Identification No.)**

1000 Louisiana, Suite 5800

Houston, Texas 77002

(Address of principal executive offices)

(Zip Code)

(713) 507-6400

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

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

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date: Class A common stock, no par value per share, 305,894,942 shares outstanding as of May 4, 2006; Class B common stock, no par value per share, 96,891,014 shares outstanding as of May 4, 2006.

DYNEGY INC.

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DEFINITIONS

As used in this Form 10-Q, the abbreviations contained herein have the meanings set forth below. Additionally, the terms Dynegy, we, us and our refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

ARB	Accounting Research Bulletin
APB	Accounting Principles Board
ARO	Asset retirement obligation
Bcf/d	Billion cubic feet per day
Cal ISO	The California Independent System Operator
Cal PX	The California Power Exchange
CDWR	California Department of Water Resources
CFTC	Commodity Futures Trading Commission
CPUC	California Public Utilities Commission
CRM	Our customer risk management business segment
CUSA	Chevron U.S.A. Inc., a wholly owned subsidiary of Chevron Corporation
DGC	Dynegy Global Communications
DHI	Dynegy Holdings Inc., our primary financing subsidiary
DMG	Dynegy Midwest Generation, Inc.
DMSLP	Dynegy Midstream Services L.P.
DMT	Dynegy Marketing and Trade
DNE	Dynegy Northeast Generation
DPM	Dynegy Power Marketing Inc.
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, Inc.
ERISA	The Employee Retirement Income Security Act of 1974, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles of the United States of America
GEN	Our power generation business
GEN-MW	Our power generation business - Midwest segment
GEN-NE	Our power generation business - Northeast segment
GEN-SO	Our power generation business - South segment
ISO	Independent System Operator
KW yr	Kilowatt year
KWh	Kilowatt hour
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MBbls/d	Thousands of barrels per day
Mcf	Thousand cubic feet
MISO	Midwest Independent Transmission Operator, Inc.
MMBtu	Millions of British thermal units
MMCFD	Million cubic feet per day
MW	Megawatts
MWh	Megawatt hour
NGL	Our natural gas liquids business segment
NOL	Net operating loss
NOV	Notice of Violation issued by the EPA
NO_x	Nitrogen oxide
NRG	NRG Energy, Inc.
NYISO	New York Independent System Operator
NYSDEC	New York State Department of Environmental Conservation

POL	Percentage of liquids
POP	Percentage of proceeds
PRB	Powder River Basin coal
REG	Our regulated energy delivery business segment
RMR	Reliability Must Run
RTO	Regional Transmission Organization
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur dioxide
SPE	Special Purpose Entity
SPN	Second Priority Senior Secured Notes
VaR	Value at Risk
VIE	Variable Interest Entity

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DYNEGY INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited) (in millions, except share data)

	March 31, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,691	$ 1,549
Restricted cash	78	397
Accounts receivable, net of allowance for doubtful accounts of $103 and $103, respectively	329	611
Accounts receivable, affiliates	1	29
Inventory	209	214
Assets from risk-management activities	288	665
Deferred income taxes	19	14
Prepayments and other current assets	144	227
Total Current Assets	2,759	3,706
Property, Plant and Equipment	6,613	6,515
Accumulated depreciation	(1,247)	(1,192)
Property, Plant and Equipment, Net	5,366	5,323
Other Assets		
Unconsolidated investments	6	270
Restricted investments	83	85
Assets from risk-management activities	83	165
Intangible assets	391	392
Deferred income taxes	1	3
Other long-term assets	181	182
Total Assets	$ 8,870	$ 10,126
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 236	$ 504
Accounts payable, affiliates	1	46
Accrued interest	126	159
Accrued liabilities and other current liabilities	246	649
Liabilities from risk-management activities	308	687
Notes payable and current portion of long-term debt	70	71
Total Current Liabilities	987	2,116
Long-term debt	4,014	4,028
Long-term debt to affiliates	200	200
Long-Term Debt	4,214	4,228
Other Liabilities		

Liabilities from risk-management activities	138	255
Deferred income taxes	570	558
Other long-term liabilities	422	429
Total Liabilities	6,331	7,586
Commitments and Contingencies (Note 10)		
Redeemable Preferred Securities, redemption value of $400 at March 31, 2006 and December 31, 2005, respectively	400	400
Stockholders Equity		
Class A Common Stock, no par value, 900,000,000 shares authorized at March 31, 2006 and December 31, 2005; 307,559,414 and 305,129,052 shares issued and outstanding at March 31, 2006 and December 31, 2005, respectively	2,953	2,949
Class B Common Stock, no par value, 360,000,000 shares authorized at March 31, 2006 and December 31, 2005; 96,891,014 shares issued and outstanding at March 31, 2006 and December 31, 2005	1,006	1,006
Additional paid-in capital	46	51
Subscriptions receivable	(8)	(8)
Accumulated other comprehensive income, net of tax	8	4
Accumulated deficit	(1,797)	(1,793)
Treasury stock, at cost, 1,780,338 shares at March 31, 2006 and 1,714,384 shares at December 31, 2005	(69)	(69)
Total Stockholders Equity	2,139	2,140
Total Liabilities and Stockholders Equity	$ 8,870	$ 10,126

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited) (in millions, except per share data)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Revenues	$ 600	$ 462
Cost of sales, exclusive of depreciation shown separately below	(409)	(530)
Depreciation and amortization expense	(60)	(55)
Impairment and other charges	(2)	1
General and administrative expenses	(51)	(263)
Operating income (loss)	78	(385)
Earnings from unconsolidated investments	2	3
Interest expense	(98)	(89)
Other income and expense, net	20	3
Income (loss) from continuing operations before income taxes	2	(468)
Income tax benefit (expense) (Note 13)	(3)	174
Loss from continuing operations	(1)	(294)
Income from discontinued operations, net of tax expense of $1 and $18, respectively	1	32
Loss before cumulative effect of change in accounting principle		(262)
Cumulative effect of change in accounting principle, net of tax expense of zero and zero, respectively	1	
Net income (loss)	1	(262)
Less: preferred stock dividends	5	5
Net loss applicable to common stockholders	$ (4)	$ (267)
Earnings (Loss) Per Share (Note 9):		
Basic earnings (loss) per share:		
Loss from continuing operations	$ (0.01)	$ (0.79)
Earnings from discontinued operations		0.09
Cumulative effect of change in accounting principle		
Basic loss per share	$ (0.01)	$ (0.70)
Diluted earnings (loss) per share:		
Loss from continuing operations	$ (0.01)	$ (0.79)
Earnings from discontinued operations		0.09
Cumulative effect of change in accounting principle		
Diluted loss per share	$ (0.01)	$ (0.70)
Basic shares outstanding	400	379

Diluted shares outstanding	526	505

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (in millions)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 1	$ (262)
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Depreciation and amortization	63	79
Impairment and other charges	2	(1)
Earnings from unconsolidated investments, net of cash distributions	(2)	(1)
Risk-management activities	(41)	(11)
Loss (gain) on sale of assets, net	(1)	1
Deferred income taxes	6	(156)
Cumulative effect of change in accounting principle, net of tax (Note 1)	(1)	
Legal and settlement charges	15	68
Independence toll settlement charge		183
Other	15	(5)
Changes in working capital:		
Accounts receivable	310	(128)
Inventory	9	26
Prepayments and other assets	76	29
Accounts payable and accrued liabilities	(763)	131
Changes in non-current assets	(2)	(1)
Changes in non-current liabilities	2	14
Net cash used in operating activities	(311)	(34)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(18)	(54)
Proceeds from asset sales, net	205	(5)
Business acquisitions, net of cash acquired	(40)	(120)
Decrease (increase) in restricted cash and restricted investments	322	(17)
Net cash provided by (used in) investing activities	469	(196)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Repayments of long-term borrowings		(19)
Proceeds from issuance of capital stock	3	2
Dividends and other distributions, net	(11)	(11)
Other financing, net	(8)	1
Net cash used in financing activities	(16)	(27)
Net increase (decrease) in cash and cash equivalents	142	(257)
Cash and cash equivalents, beginning of period	1,549	628

Cash and cash equivalents, end of period	$ 1,691	$ 371

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited) (in millions)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Net income (loss)	$ 1	$ (262)
Cash flow hedging activities, net:		
Unrealized mark-to-market gains (losses) arising during period, net	19	(18)
Reclassification of mark-to-market (gains) losses to earnings, net	(14)	12
Changes in cash flow hedging activities, net (net of tax benefit (expense) of ($3) and $4, respectively)	5	(6)
Foreign currency translation adjustments	(1)	
Other comprehensive income (loss), net of tax	4	(6)
Comprehensive income (loss)	$ 5	$ (268)

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

Note 1 Accounting Policies

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with the instructions to interim financial reporting as prescribed by the SEC. The year-end condensed consolidated balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP. These interim financial statements should be read together with the consolidated financial statements and notes thereto included in our Form 10-K for the year ended December 31, 2005, which we refer to as our Form 10-K, and our Form 10-K for the year ended December 31, 2005, as amended on April 28, 2006, which we refer to as our Form 10-K/A.

The unaudited condensed consolidated financial statements contained in this report include all material adjustments that, in the opinion of management, are necessary for a fair statement of the results for the interim periods. The results of operations for the interim periods presented in this Form 10-Q are not necessarily indicative of the results to be expected for the full year or any other interim period due to seasonal fluctuations in demand for our energy products and services, changes in commodity prices, timing of maintenance and other expenditures and other factors. The preparation of the unaudited condensed consolidated financial statements in conformity with GAAP requires management to make estimates and judgments that affect our reported financial position and results of operations. These estimates and judgments also impact the nature and extent of disclosure, if any, of our contingent liabilities. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are primarily used in (1) developing fair value assumptions, including estimates of future cash flows and discount rates, (2) analyzing tangible and intangible assets for possible impairment, (3) estimating the useful lives of our assets, (4) assessing future tax exposure and the realization of tax assets, (5) determining amounts to accrue for contingencies, guarantees and indemnifications and (6) estimating various factors used to value our pension assets and liabilities. Actual results could differ materially from any such estimates. Certain reclassifications have been made to prior period amounts in order to conform to current year presentation.

Asset Retirement Obligations. At December 31, 2005, our ARO liabilities were $48 million for our GEN-MW segment and $8 million for our GEN-NE segment. These retirement obligations related to activities such as ash pond and landfill capping, dismantlement of power generation facilities, closure and post-closure costs, environmental testing, remediation, monitoring and land and equipment lease obligations. We continue to follow the provisions for disclosure and accounting for these AROs under SFAS No. 143, Asset Retirement Obligations. During the three months ended March 31, 2006 and 2005, there were no material additional AROs recorded or settled, and our accretion expenses and revisions to estimated cash flows were not material. At March 31, 2006, our ARO liabilities were $49 million for our GEN-MW segment and $8 million for our GEN-NE segment.

Accounting Principles Adopted

SFAS No. 123(R). 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 used the prospective method of transition as described under SFAS No. 148.

In December 2004, the FASB issued SFAS No. 123(R), Share-Based Payment, which revises SFAS No. 123. SFAS No. 123(R) requires all companies to expense the fair value of employee stock options and other forms of stock-based compensation. We adopted SFAS No. 123(R) effective January 1, 2006, using the modified prospective transition method permitted under this pronouncement. Our cumulative effect of implementing this standard, which consists entirely of a forfeiture adjustment, was less than $1 million after tax. The application of SFAS 123(R) had no material impact on the unaudited condensed consolidated statements of cash flows and basic and diluted loss per share for the three months ended March 31, 2006, compared to amounts that would have been reported pursuant to our previous accounting.

In November 2005, the FASB issued FSP No. 123(R)-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards. We have adopted the short-cut method to calculate the beginning balance of the additional paid-in-capital (or APIC) pool of the excess tax benefit, and to determine the subsequent impact on the APIC pool and unaudited condensed consolidated statements of cash flows of the tax effects of employee stock-based compensation awards that were outstanding upon our adoption of FAS 123(R). Utilizing the short-cut method, we have determined that we have a Pool of Windfall tax benefits that can be utilized to offset future shortfalls that may be incurred.

Under SFAS No. 148 s 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 have recognized compensation expense over the applicable vesting periods. No in-the-money stock options have been granted since 1999.

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 loss and basic and diluted loss per share amounts would not have been impacted for the three-month periods ended March 31, 2006 and 2005.

Our share-based payments primarily consist of stock options and restricted stock awards. For stock options, we determine the fair value of each stock option at the grant date using a Black-Scholes model, with the following weighted-average assumptions used for grants for the three months ended March 31, 2006 and 2005: dividends per quarter of zero; expected volatility (historical) of 48.8% and 84.1%, respectively; a risk-free interest rate of 5.1% and 4.2%, respectively based upon observed interest rates appropriate for the term of our employee stock options; and an expected option life of 10 years for options granted prior to 2006 and 6 years for options granted during the first quarter 2006, which we calculate using the simplified methodology suggested by SAB 107. For restricted stock awards, we consider the fair value to be the closing price of the stock on the grant date. We recognize the fair value of our share-based payments over the vesting periods of the awards, which is typically a three-year service period.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

We have nine stock option plans, all of which contain authorized shares of our Class A common stock. Each option granted is exercisable at a strike price, which ranges from $0.88 per share to $57.95 per share for options currently outstanding. A brief description of each plan is provided below:

NGC Plan. Created early in our history and revised prior to Dynegy becoming a publicly traded company in 1996, this plan contains 13,651,802 authorized shares, has a 10-year term, and expires in May 2006. All option grants are vested.

Employee Equity Plan. This plan expired in May 2002 and is the only plan in which we granted options below the fair market value of Class A common stock on the date of grant. This plan contains 20,358,802 authorized shares, and grants from this plan vest on the fifth anniversary from the date of the grant. All option grants are vested.

Illinova Plan. Adopted by Illinova prior to the merger with Dynegy, this plan expired upon the merger date in February 2000 and contains 3,000,000 authorized shares. All option grants are vested.

Extant Plan. Adopted by Extant prior to its acquisition by Dynegy, this plan expired in September 2000 and contains 202,577 authorized shares. Grants from this plan vest at 25% per year. All option grants are vested.

UK Plan. This plan contains 276,000 authorized shares and has been terminated. All option grants are vested.

Dynegy 1999 Long-Term Incentive Plan (LTIP). This annual compensation plan contains 6,900,000 authorized shares, has a 10-year term and expires in 2009. All option grants are vested.

Dynegy 2000 LTIP. This annual compensation plan, created for all employees upon the merger of Illinova and Dynegy, contains 10,000,000 authorized shares, has a 10-year term and expires in February 2010. Grants from this plan vest in equal annual installments over a three-year period.

Dynegy 2001 Non-Executive LTIP. This plan is a broad-based plan and contains 10,000,000 authorized shares, has a 10-year term and expires in September 2011. Grants from this plan vest in equal annual installments over a three-year period.

Dynegy 2002 LTIP. This annual compensation plan contains 10,000,000 authorized shares, has a 10-year term and expires in May 2012. Grants from this plan vest in equal annual installments over a three-year period.

All of our option plans cease vesting for employees who are terminated for cause. For voluntary and involuntary termination, disability, retirement or death, continued vesting and/or an extended period in which to exercise vested options may apply, dependent upon the terms of the grant agreement in which a specific grant was awarded. It has been our practice to issue shares of common stock upon exercise of stock options generally from previously unissued shares. All options granted to employees vest immediately upon the occurrence of a change in control in accordance with the terms of the applicable Severance Pay Plan.

In the first quarter of 2006, we granted stock based-compensation awards that clift vest after three years based on our cumulative operating cash flows for 2006-2008. Compensation expense recorded in the first quarter related to these performance units was less than $1 million and accrued in other long-term liabilities in our unaudited condensed consolidated balance sheets.

During the first quarter 2006 we entered into an exchange transaction with our Chairman and CEO. Under the terms of the transaction, the purpose of which was to address uncertainties created by proposed regulations issued in late 2005 pursuant to Section 409A of the Internal Revenue Code, we cancelled all of the 2,378,605 stock options then held by our Chairman and CEO. As consideration for canceling these stock options, we granted our Chairman and CEO 967,707 stock options at an exercise price of $4.88, which equaled the closing price of our Class A common stock on the date of grant, and agreed to make a cash payment of $5,565,187 based on the in-the-money value of the vested stock options that were cancelled. This cash payment, which will accrue interest at 7.5% annually, will be made on January 15, 2007. The newly granted stock options have a term of 10 years, vest in three equal annual installments beginning on the first anniversary of the grant date and are subject to earlier vesting upon a constructive termination, a termination without cause or a termination resulting from a change in control. We recorded a liability to reflect the agreed upon cash payment. We were not required to record any incremental compensation expense in connection with the transaction.

Options outstanding as of March 31, 2006 are summarized below:

	Options	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Life (in years)**	**Aggregate Intrinsic Value (in millions)**
Outstanding at December 31, 2005	9,314	$ 12.66		
Granted	3,268	$ 4.88		
Exercised	(1,007)	$ 3.46		
Forfeited or expired	(2,482)	$ 2.78		
Outstanding at March 31, 2006	9,093	$ 13.58	6.5	$ 2.4
Vested and unvested expected to vest at March 31, 2006	8,141	$ 14.60	6.1	$ 2.3
Exercisable at March 31, 2006	5,331	$ 19.77	4.2	$ 2.2

The weighted average grant-date fair value of options granted during the three months ended March 31, 2006 and 2005 was $2.61 and $3.66, respectively. The total intrinsic value of options exercised for the three-month periods ended March 31, 2006 and 2005 was $3 million and zero, respectively.

Restricted stock activity for the three months ended March 31, 2006 was as follows:

	Number of Shares	**Weighted Average Grant Date Fair Value**
Nonvested at December 31, 2005	1,239	$ 4.40
Granted	1,311	$ 4.88
Vested	(225)	$ 4.38
Forfeited	(28)	$ 4.71
Nonvested at March 31, 2006	2,297	$ 4.67

Compensation expense related to options granted and restricted stock awarded totaled $1 million and $2 million for the quarters ended March 31, 2006 and 2005, respectively. Tax benefits for compensation expense related to options granted and restricted stock awarded totaled zero and $1 million for the quarters ended March 31, 2006 and 2005, respectively. We recognize compensation expense ratably over the vesting period of the respective awards. As of March 31, 2006, $14 million of total unrecognized compensation expense related to options granted and restricted stock awarded is expected to be recognized over a weighted-average period of 2.7 years. The total fair value of shares vested during the three months ended March 31, 2006 and 2005 was $4 million and $2 million, respectively. We did not capitalize nor use cash to settle any stock based compensation in the first quarter 2006.

Cash received from option exercises for the three months ended March 31, 2006 was $4 million. The tax benefit realized for the additional tax deduction from share-based payment awards totaled $1 million for the three months ended March 31, 2006.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

SFAS No. 154. In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections - A Replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle and applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS No. 154 requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. The provisions of SFAS No. 154 are effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. The adoption of this standard on January 1, 2006 did not have a material effect on our results of operations, financial position or cash flows.

Note 2 Acquisition

Rocky Road. On March 31, 2006, we completed our acquisition of NRG s 50% ownership interest in Rocky Road Power LLC (Rocky Road), the entity that owns the Rocky Road power plant, a 364-megawatt natural gas-fired peaking facility near Chicago (of which we already owned 50%). We paid approximately $45 million for NRG s ownership interest in Rocky Road. As a result of the acquisition, we became the primary beneficiary of the entity as provided under the guidance in FIN No. 46R, and thus consolidated the assets and liabilities of the entity at March 31, 2006. Please see Note 6 Unconsolidated Investments Variable Interest Entities for further discussion.

Note 3 Dispositions, Contract Terminations and Discontinued Operations

Dispositions and Contract Terminations

West Coast Power. On March 31, 2006, we completed our sale to NRG of our 50% ownership interest in WCP (Generation) Holdings LLC (West Coast Power) a joint venture between us and NRG which has ownership in the West Coast Power power plants totaling approximately 1,800 megawatts in southern California, for approximately $205 million. We did not recognize a material gain or loss on the sale. Pursuant to our divestiture of West Coast Power, we no longer maintain a significant variable interest in the entity as provided by the guidance in FIN No. 46R. Please see Note 6 Unconsolidated Investments Variable Interest Entities for further discussion.

Sterlington Contract Termination. In December 2005, we entered into an agreement to terminate the Sterlington long-term wholesale power tolling contract with Quachita Power LLC. Under the terms of the agreement, in March 2006, we paid Quachita Power LLC, a joint venture of GE Energy Financial Services and

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

Cogentrix Energy, Inc., approximately $370 million to eliminate approximately $449 million in capacity payment obligations through 2012 and avoid approximately $295 million in additional capacity payment obligations that would arise if Quachita exercised its option to extend the contract through 2017. We recognized a pre-tax charge of approximately $364 million ($229 million after-tax) in the fourth quarter 2005 related to this transaction.

Discontinued Operations

As part of our restructuring plan, we sold or liquidated our communications business and our U.K. CRM business in 2003. During 2005, we sold DMSLP, which comprised substantially all of the operations of our NGL segment. These transactions have been accounted for as discontinued operations under SFAS No. 144, as further described below.

Natural Gas Liquids. On October 31, 2005, we completed the sale of DMSLP, which comprised substantially all remaining operations of our NGL segment, to Targa Resources Inc. (Targa) and two of its subsidiaries for $2.44 billion in cash. At closing, we received $2.35 billion in cash proceeds. As of March 31, 2006, we received a substantial majority of the balance of the sales proceeds from Targa, which represented our cash collateral related to DMSLP. Targa assumed responsibility for approximately $47 million in letters of credit provided by us for the benefit of DMSLP, and those letters of credit were all replaced by December 31, 2005.

Pursuant to SFAS No. 144, we are reporting the results of NGL s operations as a discontinued operation. Accordingly, the results of operations of our NGL segment have been included in discontinued operations for all periods presented. EITF Issue 87-24, Allocation of Interest to Discontinued Operations, requires that interest expense on debt that is required to be repaid upon the sale of DMSLP should be reclassified to discontinued operations. Therefore, interest expense on our former term loan and our former generation facility debt was allocated to discontinued operations, as the respective debt instruments were paid upon the sale of DMSLP. Such interest expense, inclusive of amortization of debt issuance costs, totaled zero and $11 million for the three months ended March 31, 2006 and 2005, respectively.

Additionally, results from NGL s operations include revenues and cost of sales arising from intersegment transactions, which ceased after the sale of DMSLP. NGL processed natural gas and sold this natural gas to CRM for resale to third parties. NGL also purchased natural gas from CRM and electricity from GEN. As the intersegment revenues and cost of sales included in NGL s results were reclassified to discontinued operations, the effects of these intersegment transactions eliminated in consolidation, including the ultimate third-party settlement, previously recorded in other segments, were also reclassified to discontinued operations.

Other. We sold or liquidated some of our operations during 2003, including our communications business and our U.K. CRM business, which have been accounted for as discontinued operations under SFAS No. 144.

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(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

The following table summarizes information related to all of our discontinued operations, including the NGL operations discussed above:

	U.K. CRM	DGC	NGL	Total
		(in millions)		
Three Months Ended March 31, 2006				
Income from operations before taxes	$ 1	$	$ 1	$ 2
Income from operations after taxes			1	1
Three Months Ended March 31, 2005				
Revenues	$	$	$ 1,046	$ 1,046
Income from operations before taxes	4		46	$ 50
Income (loss) from operations after taxes	4	(1)	29	32

In the first quarter 2005, we recognized $4 million of pre-tax income associated with U.K. CRM s receipt of $4 million from a third party bankruptcy settlement.

Note 4 Restructuring Charges

2005 Restructuring. In December 2005, in order to better align our corporate cost structure with a single line of business and as part of a comprehensive effort to reduce on-going operating expenses, we announced a restructuring plan (the 2005 Restructuring Plan). The 2005 Restructuring Plan resulted in a reduction of approximately 40 positions and was substantially complete by March 31, 2006. We recognized a pre-tax charge, primarily in our Other segment, of $11 million in the fourth quarter 2005. We recognized approximately $2 million of charges in the first quarter 2006, when transitional services were completed by certain affected employees. These charges related entirely to severance costs.

The following is a schedule of 2006 activity for the severance liabilities recorded in connection with this restructuring (in millions):

Balance at December 31, 2005	$ 9
2006 adjustments to liability	2
Cash payments	(10)
Balance at March 31, 2006	$ 1

2002 Restructuring. In October 2002, we announced a restructuring plan designed to improve operational efficiencies and performance across our lines of business.

The following is a schedule of 2006 activity for the liabilities recorded in connection with this restructuring:

	Severance	Cancellation	Total

		Fees and Operating Leases	
		(in millions)	
Balance at December 31, 2005	$ 3	$ 16	$ 19
Cash payments		(2)	(2)
Balance at March 31, 2006	$ 3	$ 14	$ 17

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We expect the $14 million accrual as of March 31, 2006 associated with cancellation fees and operating leases to be paid by the end of 2007, when the leases expire.

Note 5 Risk Management Activities and Accumulated Other Comprehensive Income

The nature of our business necessarily involves market and financial risks. We enter into financial instrument contracts in an attempt to mitigate or eliminate these various risks. These risks and our strategy for mitigating them are more fully described in Note 6 Risk Management Activities and Financial Instruments beginning on page F-32 of our Form 10-K/A.

Cash Flow Hedges. We enter into financial derivative instruments that qualify as cash flow hedges. Instruments related to our GEN business are entered into for purposes of hedging future fuel requirements and sales commitments and locking in future margin. Interest rate swaps have been used to convert floating interest-rate obligations to fixed-rate obligations.

During the three months ended March 31, 2006, there was no 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 three months ended March 31, 2005, we recorded a $4 million charge related to 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 three months ended March 31, 2006 and 2005, 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 March 31, 2006 is expected to be reclassified to future earnings, contemporaneously with the related purchases of fuel, sales of electricity and payments of interest, as applicable to each type of hedge. Of this amount, after-tax losses of approximately $2 million are currently estimated to be reclassified into earnings over the 12-month period ending March 31, 2007. 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 floating-rate debt. During the three months ended March 31, 2006 and 2005, 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 three months ended March 31, 2006 and 2005, no amounts were recognized in relation to firm commitments that no longer qualified as fair value hedges.

Net Investment Hedges in Foreign Operations. Although we have exited a substantial amount of our foreign operations, we have remaining investments in foreign subsidiaries, the net assets of which are exposed to currency exchange-rate volatility. As of March 31, 2006, we had no net investment hedges in place.

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(Unaudited)

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Accumulated Other Comprehensive Income. Accumulated other comprehensive income, net of tax, is included in stockholders equity on our unaudited condensed consolidated balance sheets as follows:

	March 31, 2006	December 31, 2005
	(in millions)	
Cash flow hedging activities, net	$ 3	$ (2)
Foreign currency translation adjustment	23	24
Minimum pension liability	(18)	(18)
Accumulated other comprehensive income, net of tax	$ 8	$ 4

Note 6 Unconsolidated Investments

A summary of our unconsolidated investments is as follows:

	March 31, 2006	December 31, 2005
	(in millions)	
Equity affiliates:		
GEN MW	$	$ 60
GEN SO	6	210
Total unconsolidated investments	$ 6	$ 270

Summarized aggregate financial information for unconsolidated equity investments and our equity share thereof was:

	Three Months Ended March 31, 2006 Total	2006 Equity Share	2005 Total	2005 Equity Share
	(in millions)			
Revenues	$ 34	$ 17	$ 176	$ 72
Operating income	8	4	13	4
Net income	6	3	14	4

Earnings from unconsolidated investments of $2 million for the three months ended March 31, 2006, include the $3 million above, offset by a $1 million impairment of our investment in Panama. Earnings from unconsolidated investments of $3 million for the three months ended March 31, 2005 include the $4 million above, offset by $1 million of earnings from NGL investments, which are included in income from discontinued operations.

On March 31, 2006, we completed the sale to NRG of our 50% ownership interest in our unconsolidated investment in West Coast Power as well as our acquisition of NRG s ownership interest in Rocky Road. As a result of the transactions, we received net cash proceeds of approximately $160 million from NRG. Under the terms of this agreement, we did not recognize a material gain or loss on the sale of West Coast Power. For further discussion, please see Note 2 Acquisition and Note 3 Dispositions, Contract Terminations, and Discontinued Operations Dispositions and Contract Terminations West Coast Power.

Variable Interest Entities. In conjunction with our prior adoption of FIN No. 46(R), Rocky Road LLC was identified as a variable interest entity. At the time of adoption, we were not the primary beneficiary of, and therefore did not consolidate Rocky Road. We did not absorb a majority of the entity s expected losses, nor receive a majority of the expected residual returns.

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On March 31, 2006, we completed our acquisition of NRG s 50% ownership interest in Rocky Road and the sale to NRG of our 50% ownership interest in West Coast Power. We paid approximately $45 million for NRG s ownership interest in Rocky Road and received approximately $205 million for our ownership interest in West Coast Power, thus resulting in the receipt of net cash proceeds of approximately $160 million from NRG. Based on our acquisition of NRG s ownership interest in Rocky Road, we were required to reconsider whether we were the primary beneficiary of Rocky Road. As we now own 100% of the outstanding equity interests in Rocky Road, we are subjected to a majority of the entity s expected losses and expected residual returns, and are therefore considered the primary beneficiary of the entity. Thus, we consolidated the assets and liabilities of the entity at March 31, 2006, in accordance with the guidance provided in FIN No. 46(R), which requires that the assets and liabilities of the newly consolidated entity be measured and recorded at their fair values on the date we became the primary beneficiary. Those assets and liabilities primarily consisted of $9 million of working capital, a $16 million intangible asset related to a contract to provide capacity and energy, and $63 million of property, plant, and equipment at the facility s location.

In conjunction with acquiring the remaining outstanding equity interest in Rocky Road, we divested our interest in West Coast Power. Based on that transaction, we no longer maintain a significant variable interest in West Coast Power.

On January 31, 2005, we completed the acquisition of ExRes SHC, Inc., the parent company of Sithe Energies, Inc., which we refer to as Sithe Energies, and Sithe/Independence Power Partners, L.P., which we refer to as Independence. ExRes SHC, Inc., which we refer to as ExRes, owns through its subsidiaries four hydroelectric generation facilities in Pennsylvania. The entities owning these facilities meet the definition of VIEs. In accordance with the purchase agreement, Exelon Corporation, which we refer to as Exelon, has the sole and exclusive right to direct our efforts to decommission, sell, or otherwise dispose of the hydroelectric facilities owned through the VIE entities. Exelon is obligated to reimburse ExRes for all costs, liabilities, and obligations of the entities owning these facilities, and to indemnify ExRes with respect to the past and present assets and operations of the entities. As a result, we are not the primary beneficiary of the entities, and have not consolidated them in accordance with the provisions of FIN No. 46(R).

These hydroelectric generation facilities have commitments and obligations that are off-balance sheet with respect to Dynegy arising under operating leases for equipment and long-term power purchase agreements with local utilities. As of March 31, 2006, the equipment leases have remaining terms from two to sixteen years and involve a maximum aggregate obligation of $125 million over the terms of the leases. Additionally, each of these facilities is party to a long-term power purchase agreement with a local utility. Under the terms of each of these agreements, a project tracking account, which we refer to as a Tracking Account, was established to quantify the difference between (i) the facility s fixed price revenues under the power purchase agreement and (ii) the respective utility s Public Utility Commission approved avoided costs associated with those power purchases plus accumulated interest on the balance. Each power purchase agreement calls for the hydroelectric facility to return to the utility the balance in the Tracking Account before the end of the facility s life through decreased pricing under the respective power purchase agreement. Two of the four hydroelectric facilities are currently in the Tracking Account repayment period of the contract, whereby balances are repaid through decreased pricing. This pricing cannot be decreased below a level sufficient to allow the facilities to recover their operating costs. The remaining two facilities are anticipated to begin reducing the Tracking Accounts in 2006. The aggregate balance of the Tracking Accounts as of March 31, 2006, was approximately $304 million, and the obligations with respect to each Tracking Account are secured by the

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assets of the respective facility. The decreased pricing necessary to reduce the Tracking Accounts will make the continued sale of electricity from the facilities uneconomical. As discussed above, the obligations of the four hydroelectric facilities are non-recourse to us. Under the terms of the stock purchase agreement with Exelon, we are indemnified for any net cash outflow arising from ownership of these facilities. On March 30, 2006, certain of our subsidiaries signed a Purchase and Sale Agreement with Hydro (GP) LLC and Hydro (LP) LLC for the sale of two of the hydroelectric generating facilities. The transaction is expected to close after FERC and other required approvals are received, which we expect to occur in the third quarter 2006. The transaction will have no impact on our consolidated financial statements as Exelon is entitled to the proceeds from the sale.

Note 7 Debt

Senior Secured Credit Facility. On April 19, 2006, we entered into a fourth amended and restated credit agreement (the Fourth Senior Secured Credit Facility) with Citicorp USA, Inc. and JPMorgan Chase Bank, N.A., as co-administrative agents, JP Morgan Chase Bank, N.A., as collateral agent, Citicorp USA, Inc., as payment agent, Citigroup Global Markets Inc. and JPMorgan Securities Inc., as joint lead arrangers, and the other financial institutions parties thereto as lenders. The Fourth Senior Secured Credit Facility amends our former credit facility (last amended on March 6, 2006) by increasing the amount of the existing $400 million revolving credit facility to $470 million and adding a $200 million term facility. The revolving facility, which is currently undrawn, is available for general corporate purposes and for up to $400 million in letters of credit. The term facility has been fully drawn and the proceeds placed in a collateral account to support the issuance of letters of credit. Letters of credit issued under the former credit facility will be continued under the Fourth Senior Secured Credit Facility.

The Fourth Senior Secured Credit Facility is secured by substantially all of the assets of DHI, as borrower, and certain of its subsidiaries, as subsidiary guarantors, and certain of our assets, as parent guarantor. The revolving credit facility portion of the Fourth Senior Secured Credit Facility matures April 19, 2009 and the term portion matures on January 31, 2012. Borrowings for both the revolving and term portions under the Fourth Senior Secured Credit Facility bear interest at the relevant Eurodollar rate plus a ratings based margin of 175 basis points or the relevant base rate plus a ratings based margin of 75 basis points. Letters of credit can be issued under the revolving portion of the facility at a ratings based rate of 175 basis points. An unused commitment fee of 50 basis points is payable on the unused portion of the revolving credit facility. The margin payable for borrowing, the rate payable for letters of credit and the unused commitment fee will decrease upon meeting specified improvements in Standard and Poor s and Moody s credit ratings for the facility.

The Fourth Senior Secured Credit Facility contains mandatory prepayment provisions associated with specified asset sales and dispositions (including as a result of casualty or condemnation) and the receipt of proceeds by DHI and certain of its subsidiaries of any permitted additional non-recourse indebtedness. Commencing in 2008 with respect to the fiscal year ending December 31, 2007, each year DHI will be required to apply toward the prepayment of the loans and the permanent reduction of the commitments under the revolving credit facility (or post cash collateral in lieu thereof), a portion of its excess cash flow as calculated under the Fourth Senior Secured Credit Facility for the prior fiscal year. This portion will be 50% initially and will fall to 25% when and if DHI s leverage ratio is less than or equal to 3.50 : 1.00.

The Fourth Senior Secured Credit Facility contains customary affirmative covenants and negative covenants and events of default. Subject to certain exceptions, DHI and its subsidiaries are subject to restrictions on incurring additional indebtedness, limitations on capital expenditures and limitations on dividends and other payments in respect of capital stock. The Fourth Senior Secured Credit Facility also contains certain financial covenants, including (1) a covenant (measured at the last day of the fiscal quarter as specified below) that requires DHI and certain of its

DYNEGY INC.

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subsidiaries to maintain a ratio of secured debt to adjusted EBITDA no greater than 3.5:1 (June 30 and September 30, 2006); 3.0:1 (December 31, 2006); 2.75:1 (March 31, 2007); 2.5:1 (June 30, 2007); 2.25:1 (September 30, 2007) and 2.0:1 (December 31, 2007 and thereafter) and (2) a covenant that requires DHI and certain of its subsidiaries to maintain an interest coverage ratio as of the last day of the measurement periods ending June 30 and September 30, 2006 of no less than 1.4:1; ending December 31, 2006 of no less than 1.50:1; ending March 31, June 30, September 30 and December 31, 2007 and March 31, 2008 of no less than 1.625:1, and ending June 30, 2008 and thereafter of no less than 1.75:1.

Second Priority Senior Secured Notes. On April 12, 2006, we completed a cash tender offer and consent solicitation (the SPN Tender Offer), in which we purchased $150 million of our $225 million Second Priority Senior Secured Floating Rate Notes due 2008 (the 2008 Notes), substantially all of our $625 million 9.875% Second Priority Senior Secured Notes due 2010 (the 2010 Notes) and all of our $900 million 10.125% Second Priority Senior Secured Notes due 2013 (the 2013 Notes , and collectively with the 2008 Notes and the 2010 Notes , the Second Priority Notes). In connection with the SPN Tender Offer, we amended the indenture under which the Second Priority Notes were issued, which eliminated or modified substantially all of the restrictive covenants, certain events of default and related provisions and released certain liens securing the obligations of DHI and the guarantors of the Second Priority Notes.

In the aggregate, we purchased approximately $1,664 million of Second Priority Notes. Total cash paid to repurchase these notes, including consent fees and accrued interest, was $1,904 million. We expect to record a charge of approximately $225 million in the second quarter 2006 associated with this transaction.

The remaining outstanding 2008 Notes and 2010 Notes are each redeemable at our option in accordance with the terms of the indenture governing the Second Priority Notes.

Senior Unsecured Notes. On April 12, 2006, DHI issued $750,000,000 aggregate principal amount of our 8.375% Senior Unsecured Notes due 2016 (the New Senior Notes) in a private offering (the Senior Notes Offering). The New Senior Notes are not redeemable at our option prior to maturity. The New Senior Notes are our senior unsecured obligations and rank equal in right of payment to all of our existing and future senior unsecured indebtedness, and are senior to all of our existing and any of our future subordinated indebtedness. We have not guaranteed the New Senior Notes, and the assets and operations that we own through subsidiaries other than DHI (principally our Independence plant) do not support the New Senior Notes. The proceeds from the Senior Notes Offering, together with cash on hand, were used to fund the SPN Tender Offer discussed above.

Convertible Subordinated Debentures due 2023. We currently have outstanding an offer to convert all $225 million of our 4.75% Convertible Subordinated Debentures due 2023 (the Convertible Subordinated Debentures). The offer, which is scheduled to expire on May 15, 2006, unless extended or terminated by us, contemplates our converting all $225 million of our Convertible Subordinated Debentures for shares of our Class A common stock and a cash premium (and interest on the debentures up to but not including the conversion date), which we expect to pay from cash on hand. We expect to record a charge of approximately $50 million in the second quarter 2006 associated with the closing of this transaction.

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In connection with the conversion offer, we are also soliciting consents to amend the indenture governing the Convertible Subordinated Debentures to eliminate the cross-default and cross-acceleration provisions contained in the indenture.

Note 8 Related Party Transactions

Series C Convertible Preferred Stock. As discussed in Note 15 Redeemable Preferred Securities beginning on page F-55 of our Form 10-K/A, in August 2003, we issued to Chevron 8 million shares of our Series C Convertible Preferred Stock due 2033, which we refer to as our Series C Preferred. We accrue dividends on our Series C Preferred at a rate of 5.5% per annum. We made a semi-annual dividend payment of $11 million in February 2006. Currently we are in negotiations with Chevron regarding a possible redemption of the Series C Preferred. If we and Chevron reach definitive agreements on such redemption, which could occur in the near term, we may finance such redemption, in part, by issuing shares of our Class A common stock. Any remaining amounts required to finance the redemption would be expected to come from cash on hand, proceeds from asset sales or other capital raising transactions. If consummated, such a transaction would eliminate the preferred dividend requirement.

Exchange Transaction with Chairman and CEO. On March 17, 2006 we entered into an exchange transaction with our Chairman and CEO. Under the terms of the transaction, the purpose of which was to address uncertainties created by proposed regulations issued in late 2005 pursuant to Section 409A of the Internal Revenue Code, we cancelled all of the 2,378,605 stock options then held by our Chairman and CEO. Please see Note 1 Accounting Policies Accounting Principles Adopted SFAS No.123(R) for further discussion.

Note 9 Loss Per Share

Basic loss per share represents the amount of losses for the period available to each share of common stock outstanding during the period. Diluted loss per share represents the amount of losses 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 dilutive potential common shares outstanding during the period.

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The reconciliation of basic loss per share from continuing operations to diluted loss per share from continuing operations is shown in the following table:

	Three Months Ended March 31,	
	2006	2005
	(in millions, except per share amounts)	
Loss from continuing operations	$ (1)	$ (294)
Convertible preferred stock dividends	(5)	(5)
Loss from continuing operations for basic loss per share	(6)	(299)
Effect of dilutive securities:		
Interest on convertible subordinated debentures	2	2
Dividends on Series C convertible preferred stock	5	5
Income (loss) from continuing operations for diluted loss per share	$ 1	$ (292)
Basic weighted-average shares	400	379
Effect of dilutive securities:		
Stock options and restricted stock	2	2
Convertible subordinated debentures	55	55
Series C convertible preferred stock	69	69
Diluted weighted-average shares	526	505
Loss per share from continuing operations:		
Basic	$ (0.01)	$ (0.79)
Diluted (1)	$ (0.01)	$ (0.79)

(1) When an entity has a net loss from continuing operations, SFAS No. 128, Earnings per Share, prohibits the inclusion of potential common shares in the computation of diluted per-share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for the three months ended March 31, 2006 and the three months ended March 31, 2005.

Note 10 Commitments and Contingencies

Set forth below is a description of our material legal proceedings. In addition to the matters described below, we are party to legal proceedings arising in the ordinary course of business. In management s opinion, the disposition of these ordinary course matters will not materially adversely affect our financial condition, results of operations or cash flows.

We record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable under SFAS No. 5, Accounting for Contingencies. For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Please see Note 2 Accounting Policies Contingencies, Commitments, Guarantees and Indemnifications beginning on page F-17 of our Form 10-K/A for further discussion of our reserve policies. Environmental reserves do not reflect management s assessment of the insurance coverage that may be applicable to the matters at issue, whereas litigation reserves do reflect such potential coverage. We cannot make any assurances that the amount of any reserves or potential insurance coverage will be sufficient to cover the cash obligations we might incur as a result of litigation or regulatory proceedings, payment of which could be material.

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With respect to some of the items listed below, management has determined that a loss is not probable or that any such loss, to the extent probable, is not reasonably estimable. In some cases, management is not able to predict with any degree of certainty the range of possible loss that could be incurred. Notwithstanding these facts, management has assessed these matters based on current information and made a judgment concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of damages sought and the probability of success. Management s judgment may, as a result of facts arising prior to resolution of these matters or other factors, prove inaccurate and investors should be aware that such judgment is made subject to the known uncertainty of litigation.

Enron Trade Credit Litigation. Shortly before their bankruptcy filing in the fourth quarter 2001, we determined that we had net exposure to Enron Corp. and its affiliates, including certain liquidated damages and other amounts relating to the termination of commercial transactions among the parties, of approximately $84 million. This exposure was calculated by setting off approximately $230 million owed from Dynegy entities to Enron entities against approximately $314 million owed from Enron entities to Dynegy entities. The master netting agreement between Enron and us and the valuation of the commercial transactions covered by the agreement, which valuation is based principally on the parties assessment of market prices for such period, remain subject to dispute. Enron has claimed that the master netting agreement is unenforceable. If it prevails, our potential liability to Enron could be approximately $216 million before interest, with as much as $220 million in unsecured Dynegy claims remaining to enforce against the bankruptcy estate. As required by the master netting agreement, we pursued resolution of this dispute through arbitration; however, the Bankruptcy Court did not grant our motion, which was opposed by Enron, to permit arbitration with a non-bankrupt Enron entity. We then filed a motion with the Bankruptcy Court to allow us to proceed to discovery and trial in order to determine the enforceability of the master netting agreement under the U.S. Bankruptcy Code. The Bankruptcy Court denied our motion and ordered us to mediate the dispute with Enron. The parties commenced mediation in November 2004, and have had further discussions since that time, but no settlement has been reached. In April 2006, Enron requested that mediation be terminated; the mediator has recommended that the case be returned to the Bankruptcy Court.

If the setoff rights in the master netting agreement are modified or disallowed, either by agreement or otherwise, the amount available for our entities to set off against sums that might be due Enron entities could be reduced materially. In fact, we could be required to pay to Enron the full amount that it claims to be owed, while we would be an unsecured creditor of Enron to the extent of our claims. Given the size of the claims at issue, an adverse result could have a material adverse effect on our financial condition, results of operations and cash flows. We have recorded a reserve that we consider reasonable in connection with this matter.

Gas Index Pricing Litigation. We are defending the following suits that claim damages resulting from the alleged manipulation of gas index publications and prices by us and others: *ABAG v. Sempra Energy et al.* (filed in state court in November 2004); *Ableman Art Glass v. Encana Corporation et al.* (class action filed in federal court in December 2004); *Benschiedt* (class action filed in state court in February 2004); *Bustamante v. The McGraw Hill Companies et al*. (class action filed in state court in November 2002); *City and County of San Francisco v. Dynegy Inc. et al.* (filed in state court in July 2004); *County of San Diego v. Dynegy Inc., Dynegy Marketing and Trade, West Coast Power, et al.* (filed in state court in July 2004); *County of San Mateo v. Sempra Energy et al.* (filed in state court in December 2004); *County of Santa Clara v. Dynegy Inc., Dynegy Marketing and Trade, West Coast Power, et al.* (filed in state court in July 2004); *Fairhaven Power Company v. Encana Corp. et al. (*class action filed in federal court in September 2004); *In re Natural Gas Commodity Litigation* (class action filed in federal court in

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January 2004); *Leggett v. Duke Energy et al.* (class action filed in state court in January 2005); *Multiut v. Dynegy Inc.* (filed in federal court in December 2004); *Nelson Brothers LLC v. Cherokee Nitrogen v. Dynegy Marketing and Trade and Dynegy Inc.* (filed in state court in April 2003); *Nurserymen s Exchange v. Sempra Energy et al.* (filed in state court in October 2004); *Older v. Dynegy Inc. et al.* (filed in federal court in September 2004); *Owens-Brockway v. Sempra Energy at al.*(filed in state court in January 2005); *Sacramento Municipal Utility District (SMUD) v. Reliant Energy Services, et al.*(filed in state court in November 2004); *School Project for Utility Rate Reduction v. Sempra Energy et al.*(filed in state court in November 2004); *Sierra Pacific Resources and Nevada Power Company v. El Paso Corp. et al.*(filed in federal court in April 2003)*; Tamco v. Dynegy Inc. et al.* (filed in state court in December 2004); *Texas-Ohio Energy, Inc. v. CenterPoint Energy Inc., et al.* (class action filed in federal court in November 2003); *Utility Savings & Refund v. Reliant Energy Services, et al.* (class action filed in federal court in November 2004) and *J.P. Morgan Trust Company, National Association, in its capacity as Trustee of the FLI Liquidating Trust (Farmland) v. Dynegy Marketing and Trade, et al.* (filed in Kansas state court in July 2005). In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to gas index publications. All of the complaints rely heavily on FERC and CFTC investigations into and reports concerning index-reporting manipulation in the energy industry.

Pursuant to various motions filed by the parties to the litigation described above, the gas index pricing lawsuits pending in state court (except for *Nelson Brothers*) have been consolidated before a single judge in San Diego. These cases are now titled the Judicial Counsel Coordinated Proceeding (JCCP) 4221, 4224, 4226, and 4228, the Natural Gas Anti-Trust Cases, I, II, III, & IV, which we refer to as the Coordinated Gas Index Cases. In April 2005, defendants moved to dismiss the Coordinated Gas Index Cases on preemption and filed rate grounds. The Court denied defendants motion in June 2005 and in October 2005 the defendants filed answers to the plaintiffs complaints. The parties are presently engaged in discovery.

The *Nelson Brothers* lawsuit involves an alleged breach of a gas purchase contract and is pending in Alabama state court. The parties are presently engaged in discovery.

As to the gas index pricing lawsuits filed in federal court, the *Sierra Pacific* case was dismissed in December 2004 on defendants motion. The *Texas-Ohio* case was similarly dismissed in April 2005. Plaintiffs in *Sierra Pacific* and *Texas-Ohio* appealed the dismissals and both matters are pending before the same panel of the Ninth Circuit Court of Appeals. In December 2005, the Nevada federal court dismissed three additional cases (*Ableman Art Glass*, *Fairhaven Power* and *Utility Savings & Refund*) on similar grounds to *Texas-Ohio*, finding plaintiffs claims barred by the filed rate doctrine. In May 2005 and November 2005, the *Multiut* and *Farmland* cases (respectively) were transferred to the same Nevada federal court before which the other similarly situated federal cases are pending or were dismissed. The *Multiut* case involves a counterclaim of alleged index manipulation filed by the defendant, Multiut, against whom we have a pending breach of gas purchase contract claim. In January 2006, we filed a motion to dismiss Multiut s claims of index manipulation based upon filed rate doctrine and preemption grounds. Such motion remains pending. The plaintiffs generally seek unspecified actual and punitive damages relating to costs they claim to have incurred as a result of the alleged conduct.

In February 2006, we reached a settlement in *In re Natural Gas Commodity Litigation*, resolving a class action lawsuit by all persons who purchased, sold or settled NYMEX Natural Gas Contracts between June 1, 1999 and December 31, 2002. The underlying action alleged the named defendants (including Dynegy and West Coast Power) unlawfully manipulated and aided and abetted the manipulation of the prices of natural gas futures contracts traded on the NYMEX. Pursuant to the settlement agreement, Dynegy and West Coast Power continue to deny plaintiffs allegations, and Dynegy agreed to pay $7 million in settlement of any and all claims for damages arising from or relating in any way to trading during the Class Period in NYMEX Natural Gas Contracts. The settlement is subject to a fairness hearing and final Court approval, which we expect to occur in the third quarter 2006.

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We are analyzing all of these claims and are vigorously defending against them. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits. However, given the nature of the claims and the size of recent settlements of similar matters, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows. We have recorded reserves that we consider reasonable in connection with these matters.

In connection with the sale of our interest in West Coast Power to NRG (which sale closed on March 31, 2006), we, NRG and NRG West Coast LLC entered into an Agreement Regarding Specified Litigation in which the parties allocated responsibility for managing certain litigation and agreed to certain indemnities with respect to such litigation. Subject to conditions and limitations specified in that Agreement, the parties agreed that we would manage the gas index pricing litigation described above for which NRG could suffer a loss subsequent to the closing and that we would indemnify NRG for all costs or losses resulting from such litigation, as well as from other proceedings based on similar acts or omissions which formed the basis of such litigation. Please read Guarantees and Indemnifications WCP Indemnities below.

California Market Litigation. We and various other power generators and marketers were defendants in numerous lawsuits alleging rate and market manipulation in California s wholesale electricity market during the California energy crisis and seeking unspecified treble damages. These cases were coordinated before a single federal judge, who dismissed two of them in the first quarter of 2003 on the grounds of FERC preemption and the filed rate doctrine. The Ninth Circuit Court of Appeals affirmed these dismissals in June 2004 and September 2004, respectively. Petitions for Writ of Certiorari to the U.S. Supreme Court were both denied. The remaining five coordinated cases were remanded to a California state court, and in May 2005, defendants filed a motion to dismiss. The court granted defendants motion to dismiss in October 2005 on grounds of federal preemption. Plaintiffs have appealed the ruling to a California state appellate court.

Between April and October 2002, nine additional putative class actions and/or representative actions were filed in state and federal court on behalf of business and residential electricity consumers against us and numerous other power generators and marketers. The complaints alleged unfair, unlawful and deceptive practices in violation of the California Unfair Business Practices Act and sought injunctive relief, restitution and unspecified damages. Although some of the allegations in these lawsuits were similar to those in the cases referenced above, these lawsuits included additional allegations relating to, among other things, the validity of the contracts between these power generators and the CDWR. Following removal of these cases, the federal court dismissed eight of the nine actions and plaintiffs appealed. In February 2005, the Ninth Circuit affirmed the dismissals. The remaining case was remanded to state court, and in May 2005, defendants filed a motion to dismiss. In September 2005, the court granted defendants motion to dismiss on grounds of federal preemption.

In December 2002, two additional actions were filed on behalf of consumers and businesses in Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana that purchased energy from the California market, alleging violations of the Cartwright Act and unfair business practices. These cases were subsequently dismissed and refiled in California Superior Court as one class action complaint. We removed the action from state court and consolidated it with existing actions pending before the U.S. District Court for the Northern District of California. Plaintiffs challenged the removal and the federal court stayed its ruling pending a decision by the Ninth Circuit on the five coordinated cases referenced above. Although the Ninth Circuit issued a decision remanding the five cases, which were later dismissed, no ruling has been made with respect to the consolidated class action case.

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In May and June 2004, two additional lawsuits were filed in Oregon and Washington federal courts against several energy companies, including DPM, seeking more than $30 million in compensatory damages resulting from alleged manipulation of the California wholesale power markets. In February 2005, the respective federal courts granted our motions to dismiss. Shortly thereafter, plaintiffs in both cases filed notices of appeal to the Ninth Circuit. Briefing in both cases has been completed, and they remain pending.

In October 2004, an independent electric services provider in California filed suit against us and several other defendants alleging that the defendants, in violation of the California anti-trust and unfair business practices statutes, engaged in unfair, unlawful and deceptive practices in the California wholesale energy market from May 2000 through December 2001. Plaintiff, which formerly sold electricity generated from renewable sources in the California market, claims to have been forced out of business by the defendants conduct and is seeking $5 million in compensatory damages, as well as treble damages. We removed the action to federal court in June 2005, where it remains pending.

We believe that we have meritorious defenses to these claims and are vigorously defending against them. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits. However, given the nature of the claims, an adverse result in any of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

The energy crisis also precipitated a number of FERC actions related to the California energy market, and the Western market. These actions included investigations of alleged manipulation of energy prices in the West, claims of false reporting to energy index publishers and complaints regarding various long-term power sales contracts. The FERC investigation of false reporting to trade publications by us concluded in July 2003. Additionally, in October 2004, the FERC approved an agreement providing for the settlement of certain claims relating to western energy market transactions that occurred between January 2000 and June 2001. Please read FERC and Related Regulatory Investigations Requests for Refunds below for further discussion.

In connection with the sale of our interest in West Coast Power to NRG on March 31, 2006, we, NRG and NRG West Coast LLC entered into an Agreement Regarding Specified Litigation in which the parties allocated responsibility for managing certain litigation and agreed to certain indemnities with respect to such litigation. Subject to conditions and limitations specified in that Agreement, the parties agreed that we would manage the power litigation described above for which NRG could suffer a loss subsequent to the closing and that we and NRG would each be responsible for 50% of any costs or losses resulting from that power litigation, as well as from other proceedings based on similar acts or omissions which formed the basis of such litigation. Please read Guarantees and Indemnifications WCP Indemnities below.

FERC and Related Regulatory Investigations Requests for Refunds. In October 2004, the FERC approved an agreement with Dynegy and West Coast Power that settled FERC claims relating to western energy market transactions that occurred between January 2000 and June 2001. Market participants (other than the parties to the settlement) were permitted to opt into this settlement and share in the distribution of the settlement proceeds, and most of these other market participants have done so. The Cal ISO will determine the entitlement to refund and/or the liability of each non-settling market participant. Under the terms of the settlement, we will have no further liability to these non-settling parties. The settlement further provides that we are entitled to pursue claims for reimbursement of fuel costs against various non-settling market participants. We are currently pursuing these claims but are unable to predict the amounts that may be recovered from such parties.

The settlement does not apply to the ongoing civil litigation related to the California energy markets described above in which Dynegy and West Coast Power are defendants. The settlement also does not apply to the

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pending appeal by the CPUC and the California Electricity Oversight Board of the FERC s prior decision to affirm the validity of the West Coast Power-CDWR contract. We are currently awaiting a ruling on this appeal and cannot predict its outcome.

In connection with the sale of our interest in West Coast Power to NRG on March 31, 2006, we, NRG and NRG West Coast LLC entered into an Agreement Regarding Specified Litigation in which the parties allocated responsibility for managing certain litigation and agreed to certain indemnities with respect to such litigation. The Agreement provides that NRG will manage the CDWR litigation described above and that NRG will indemnify us for any losses in connection with such litigation with certain limits and conditions placed on that indemnification obligation. Please read Guarantees and Indemnifications WCP Indemnities below.

ERISA/Illinois Power 401(k) Litigation. In January 2005, three DMG union employees who are participants in the DMG 401(k) Savings Plan for Employees Covered Under a Collective Bargaining Agreement (formerly known as the Illinois Power Company Incentive Savings Plan For Employees Covered Under a Collective Bargaining Agreement), which we refer to as the DMG 401(k) Plan, purporting to represent all DMG and Illinois Power employees who held Dynegy common stock through the DMG 401(k) Plan during the period from February 2000 through the present, filed a lawsuit in federal court in the Southern District of Illinois against us, Illinois Power, DMG and several individual defendants. The complaint alleges violations of ERISA in connection with the DMG 401(k) Plan that are similar to the claims made in the Dynegy Inc. ERISA litigation we settled in December 2004, including claims that certain of our former officers (who are past members of our Benefit Plans Committee) breached their fiduciary duties to plan participants and beneficiaries in connection with the plan s investment in Dynegy common stock in particular with respect to our financial statements, Project Alpha, round trip trades and gas price index reporting. The lawsuit seeks unspecified damages for the losses to the plan, as well as attorney s fees and other costs. In March 2006, an amended complaint was filed naming additional former officers as defendants and amending the fraud claims.

Additionally, in September 2005, two former Illinois Power salaried employees who were participants in the Dynegy Midwest Generation, Inc. 401(k) Savings Plan for salaried employees (formerly known as the Illinois Power Incentive Savings Plan), which we refer to as the DMG Salaried Plan, purporting to represent all DMG Salaried Plan participants who held Dynegy common stock through the DMG Salaried Plan during the period from January 1, 2002 though January 30, 2003, filed a lawsuit in federal court in the Southern District of Texas against us and several individual defendants. The complaint alleges violations of ERISA in connection with the DMG Salaried Plan that are similar to the claims made in the ERISA litigation referenced in the preceding paragraph. The lawsuit seeks unspecified damages for the losses to the plan, as well as attorney s fees and other costs. In December of 2005, we filed a motion to dismiss the complaint, in response to which plaintiffs counsel filed a second putative class action on behalf of three plan alleged participants that is materially identical to the original action. In March 2006, the original action was dismissed by the court with prejudice, and the plaintiffs in that matter have appealed that dismissal. The second putative class action relating to the DMG Salaried Plan remains pending.

We believe that we have meritorious defenses to plaintiffs claims in all of these lawsuits and are vigorously defending against them. Although it is not possible to predict with certainty whether we will incur any liability in connection with these lawsuits, we do not believe that any liability we might incur as a result of this lawsuit would have a material adverse effect on our financial condition, results of operations or cash flows.

Stumpf Litigation. We and two former subsidiaries are defendants in a lawsuit filed in New York by Stumpf AG and two of its affiliates stemming from the closure of our former Austrian subsidiary s Vienna telecommunications office in the spring of 2001. The plaintiffs are seeking $29 million in compensatory and unspecified punitive damages, alleging breach of contract, tortious interference and other similar claims primarily relating to the termination of real property

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leases to which our former Austrian subsidiary was a party. These claims are based on similar lawsuits filed in Austria against our former Austrian subsidiary, which was sold to a third party in January 2003. All of these lawsuits pending in Austria have been stayed. This former subsidiary is in liquidation and one of its liquidators admitted, for purposes of the liquidation, the plaintiffs claims in the amount of $30 million. In December 2004, the plaintiffs filed a motion for partial summary judgment on issues of liability. In December 2005, the Court denied plaintiffs motion. Shortly thereafter, plaintiffs appealed the ruling to the New York Appellate Division while also seeking to stay the underlying proceedings in the trial court. In January 2006, plaintiffs motion to stay the underlying action during appeal was denied. In March 2006, the parties participated in a mediation, which failed to reach a resolution of the ongoing dispute. Oral argument on plaintiffs substantive appeal was held shortly after the mediation. A ruling from the intermediate court on plaintiffs appeal is expected later in 2006.

We continue to oppose these claims and believe we have meritorious defenses. Although it is not possible to predict with certainty whether we will incur any liability in connection with these lawsuits, we do not believe that any liability we might incur as a result of these lawsuits would have a material adverse effect on our financial condition, results of operations or cash flows. We have recorded a reserve that we consider reasonable relating to this matter.

LSP-Kendall Arbitration. In May 2005, Dynegy Power Marketing, Inc. initiated an arbitration proceeding against LSP-Kendall Energy, alleging breach of the parties long-term power purchase agreement and seeking a declaratory judgment that DPM does not owe (1) reservation payments during the period in which LSP-Kendall failed to bring dedicated generating units on-line or (2) money in connection with past incremental replacement costs. DPM s breach of contract claims are based on LSP-Kendall s failure to design, construct and maintain the dedicated units and generation facility in accordance with the terms of the power purchase agreement. In addition to its request for declaratory relief, DPM seeks an order compelling LSP-Kendall to cure the breaches by a certain date and such failure to cure entitles DPM to terminate the power purchase agreement without penalty. LSP-Kendall denies that it is in breach of the power purchase agreement and asserts counterclaims alleging DPM owes in excess of $29 million in reservation payments and past incremental replacement costs. Arbitration is currently set for June 2006 and the parties are presently engaged in discovery.

We believe we have meritorious defenses to LSP-Kendall s claims and are vigorously defending against them. We cannot predict with certainty whether we will incur any liability in connection with this arbitration, however, we do not believe that any liability we might incur would have a material adverse effect on our financial condition, results of operations or cash flows.

Stand Energy Litigation (formerly Atlantigas Corp. Litigation). In October 2004, we were named in a West Virginia federal court class action lawsuit alleging that interstate pipelines provided preferential storage and transportation services to their own unregulated marketing affiliate in return for a percentage of the profits. Plaintiffs contend that such conduct violates applicable FERC regulations and federal and state antitrust laws, and constitutes common law tortious interference with contractual and business relations. In addition, the complaint claims the defendants conspired with the other market participants to receive preferential natural gas storage and transportation services at off-tariff prices. The complaint seeks unspecified compensatory and punitive damages. Following numerous procedural motions which limited plaintiffs claims against us to state antitrust violations and resulting unjust enrichment, defendants filed their answers to plaintiffs Second Amended Complaint in September 2005. The parties are actively engaged in discovery. We continue to analyze plaintiffs claims and intend to defend against them vigorously. We cannot predict with certainty whether we will incur any liability in connection with this lawsuit; however, we believe that any liability incurred as a result of this litigation would not have a material adverse effect on our financial condition, results of operations or cash flows.

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Severance Arbitration. Our former CFO, Rob Doty, filed for arbitration pursuant to the terms of his employment/severance agreement following his departure from the company in 2002. Mr. Doty seeks payment of up to approximately $3.4 million and additional amounts related to long-term incentive payments allegedly contemplated by his agreement. Mr. Doty s agreement is subject to interpretation, and we maintain that the amount owed is lower than the amount sought. We have recorded a severance accrual that we consider reasonable relating to this proceeding.

U.S. Attorney Texas. We are continuing to cooperate fully with the U.S. Attorney s office in Houston in its ongoing investigation of the industry s gas trade reporting practices.

In January 2003, one of our former natural gas traders was indicted on three counts of knowingly causing the transmission of false trade reports used to calculate the index price of natural gas and four counts of wire fraud. A second superseding indictment was returned in March 2006, recharging the original violations and adding additional charges. The trial is scheduled for the summer of 2006.

We do not believe these investigations will have a material adverse effect on our financial condition, results of operations or cash flows.

U.S. Attorney California. The U.S. Attorney s office in the Northern District of California issued a Grand Jury subpoena requesting information related to our activities in the California energy markets in November 2002. We continue to cooperate fully with the U.S. Attorney s office in its investigation of these matters, including production of substantial documents responsive to the subpoena and other requests for information. We cannot predict the ultimate outcome of this investigation.

Department of Labor Investigation. In August 2002, the U.S. Department of Labor commenced an official investigation pursuant to Section 504 of ERISA with respect to the benefit plans we maintain and our ERISA affiliates. We cooperated with the Department of Labor throughout this investigation, which focused on a review of plan documentation, plan reporting and disclosure, plan record keeping, plan investments and investment options, plan fiduciaries and third party service providers, plan contributions and other operational aspects of the plans. In February 2005, we received a letter from the Department of Labor indicating that, as a result of our December 2004 settlement in the Dynegy Inc. ERISA litigation, it intended to take no further action with respect to its investigation of the Dynegy Inc. 401(k) Plan. However, its investigation is ongoing as it relates to the Illinois Power 401(k) Plans and the recent litigation relating to those plans described above.

Calpine Corporation Bankruptcy. Calpine Corporation filed for Chapter 11 Bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York (Bankruptcy Court) on December 20, 2005. The filing includes Nissequogue Cogen Partners (NCP), a subsidiary of Calpine, which has been purchasing gas from DMT under a long term gas sales agreement. NCP owes DMT approximately $8 million for pre-petition natural gas deliveries pursuant to the gas sales agreement, and has been paying DMT on a current basis for post-petition gas deliveries. NCP and DMT have reached a settlement pursuant to Rule 9019 of the Federal Rules of Bankruptcy Procedure and Section 105(a) of the Bankruptcy Code in which the parties agree to the mutual termination of the long term gas sales agreement and settlement of all claims between NCP and DMT. Pursuant to the settlement agreement that was filed on April 25, 2006 with the Bankruptcy Court, NCP will continue paying for post-petition gas deliveries pursuant to the gas sales agreement. DMT s obligation to deliver and receive gas will terminate on May 1, 2006, once the Bankruptcy Court issues a final order approving the settlement agreement and appeal periods have expired, NCP will pay DMT approximately $8 million (which is the actual amount owed for all pre-petition gas deliveries), the long term gas sales agreement (which otherwise would have expired on May 31, 2010) will terminate, and DMT will waive any claim for potential forward damages that it otherwise might have under the gas sales agreement.

Enron/NNG VEBA Litigation. Prior to our acquisition of NNG from Enron, NNG employees were participants in a post-retirement medical plan maintained by Enron. The plan s assets were maintained in a VEBA trust, along with the assets of other Enron companies whose plans were included in the same VEBA trust (the Enron VEBA). Enron filed for bankruptcy in December 2001. When we acquired NNG in January 2002, the assets of the Enron VEBA had not been distributed to its participant companies. In July 2002, we estimated that approximately $25.4 million of the assets of the Enron VEBA were attributable to the NNG employees who participated in the post-retirement medical plan. On July 1, 2002, as part of our sale of NNG to Mid American Energy Holdings Company, NNG established a separate VEBA trust solely for its plan participants (the NNG VEBA). As a condition of the sale agreement, we placed $25.4 million into escrow under terms providing that if Enron did not release NNG s share of the VEBA assets by August 2004, NNG was entitled to the escrowed money to fund the NNG VEBA. When Enron did not release the funds from the Enron VEBA as of August 2004, NNG drew down the escrowed funds. Pursuant to the escrow agreement, NNG was then obligated to (1) repay us if it were to recover funds from the Enron VEBA and (2) allow us to manage any litigation against the Enron VEBA for payment of amounts owed to the NNG VEBA. In January 2006, we entered a confidential agreement with NNG settling the claims between the parties and extinguishing the obligations under the escrow agreement in exchange for a cash payment by NNG to Dynegy.

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Guarantees and Indemnifications

We routinely enter into contractual agreements that contain various representations, warranties, indemnifications and guarantees. Examples of such agreements include, but are not limited to, service agreements, equipment purchase agreements, engineering and technical service agreements, and procurement and construction contracts. Some agreements contain indemnities that cover the other party s negligence or limit the other party s liability with respect to third party claims, in which event we will effectively be indemnifying the other party. Virtually all such agreements contain representations or warranties that are covered by indemnifications against the losses incurred by the other parties in the event such representations and warranties are false. While there is always the possibility of a loss related to such representations, warranties, indemnifications and guarantees in our contractual agreements, and such loss could be significant, in most cases management considers the probability of loss to be extremely remote.

WCP Indemnities. In connection with our sale to NRG of our 50% ownership interest in West Coast Power (please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations West Coast Power for further discussion), we entered into an agreement with NRG in which we agreed how certain litigation would be managed and allocated between the parties responsibility for any loss suffered by the parties as a result of such litigation. In this agreement, we agreed that we would continue managing the Gas Index Pricing Litigation and that we would indemnify NRG for all losses suffered by NRG resulting from certain cases described in Gas Index Pricing Litigation and from other proceedings based on acts or omissions similar to those which formed the basis of such litigation. We also agreed with NRG that we would continue managing the California Market Electricity Litigation and that we and NRG would each be responsible for, and indemnify the other for, 50% of any losses suffered by either party resulting from such litigation, as well as from other proceedings based on similar acts or omissions which formed the basis of such litigation. Also pursuant to this agreement, NRG will manage the litigation regarding the validity of the West Coast Power-CDWR power purchase agreement and NRG agreed to indemnify us for any losses suffered by us in connection with such litigation, subject to specified limitations.

Targa Indemnities. During 2005, as part of our sale of DMSLP, we agreed to indemnify Targa against losses it may incur under indemnifications DMSLP provided to purchasers of Hackberry and certain other assets, properties and businesses disposed of by DMSLP prior to our sale of DMSLP. We have incurred no significant expense under these prior indemnities and deem their value to be insignificant. We have also indemnified Targa for certain tax matters arising from periods prior to our sale of DMSLP. While we have incurred no expense in connection with this indemnification, as of March 31, 2006, we have recorded an accrual, which we deem to be the fair value of this indemnification.

Illinois Power Indemnities. As a condition of our 2004 sale of Illinois Power and our interest in Joppa, we provided indemnifications to third parties regarding environmental, tax, employee and other representations. These indemnifications are limited to a maximum recourse of $400 million. Additionally, we have indemnified third parties against losses resulting from possible adverse regulatory actions taken by the ICC that could prevent Illinois Power from recovering costs incurred in connection with purchased gas and investments in specified items. Although there is no limitation on our liability under this indemnity, our indemnity is limited to 50% of any such losses. Illinois Power had not sustained any material losses in recent years and, at the time of the sale of Illinois Power to Ameren, our management considered the probability of any material loss under this indemnity remote. Consequently, the value of the indemnification was initially deemed to be insignificant. In the second quarter of 2005, however, the ICC rejected an Administrative Law Judge s proposed order and entered an order in one of the

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proceedings covered by the scope of this indemnification that disallowed items relating to one of Illinois Power s gas storage fields, resulting in a negative revenue requirement impact to Ameren. On July 27, 2005, we made a payment of $8 million to Ameren in settlement of Ameren s indemnification claims with respect to this ICC order. Although the ICC has not issued an order in any other cases, there are other cases in which it is now probable, based on this recent action by the ICC, that some loss may occur and a liability can be reasonably estimated. As a result, in the second quarter 2005, we recognized a pre-tax charge of $12 million, which is included in general and administrative expense on our consolidated statements of operations. Further disallowances and other events which fall within the scope of the indemnity may still occur; however, we are not required to accrue a liability in connection with these indemnifications, as management cannot reasonably estimate a range of outcomes or at this time consider the probability of an adverse outcome as only reasonably possible. We intend to contest any proposed disallowances.

Constellation Guarantee. During 2004, as part of entering into a back-to-back power purchase agreement with Constellation, under which Constellation effectively received our rights to purchase approximately 570 MW of capacity and energy arising under our Kendall tolling contract, we guaranteed Constellation an aggregate $3.5 million in reactive power revenues over the four year term of the power purchase agreement. Upon entering into this contract, we established a liability of $0.3 million reflecting the fair value of this guarantee. During the year ended December 31, 2005, we increased the liability by approximately $1 million, as it became probable that we will be obligated to make a greater payment to Constellation under the guarantee.

Northern Natural and Other Indemnities. During 2003, as part of our sale of Northern Natural, the Rough and Hornsea gas storage facilities and certain natural gas liquids assets, we provided indemnities to third parties regarding environmental, tax, employee and other representations. Maximum recourse under these indemnities is limited to $209 million, $857 million and $28 million for the Northern Natural, Rough and Hornsea gas storage facilities and natural gas liquids assets, respectively. We also entered into similar indemnifications regarding environmental, tax, employee and other representations when completing other asset sales such as, but not limited to, Hackberry LNG Project, SouthStar Energy Services, various Canadian assets, Michigan Power, Oyster Creek, Hartwell, Commonwealth, Sherman, Indian Basin and PESA. We carry reserves for existing environmental, tax and employee liabilities and have incurred no other expense relating to these indemnities.

Black Mountain Guarantee. Through one of our subsidiaries, we hold a 50% ownership interest in Black Mountain (Nevada Cogeneration), in which our partner is a Chevron subsidiary which owns the Black Mountain power generation facility and has a power purchase agreement with a third party that extends through April 2023. In connection with the power purchase agreement, pursuant to which Black Mountain (Nevada Cogeneration) receives payments which decrease in amount over time, we agreed to guarantee 50% of certain payments that may be due to the power purchaser under a mechanism designed to protect it from early termination of the agreement. At March 31, 2006, if an event of default had occurred under the terms of the mortgage on the facility entered into in connection with the power purchase agreement, we could have been required to pay the power purchaser approximately $54 million under the guarantee. In addition, while there is a question of interpretation regarding the existence of an obligation to make payments calculated under this mechanism upon the scheduled termination of the agreement, management does not expect that any such payments would be required.

Note 11 Regulatory Issues

We are subject to regulation by various federal, state, local and foreign agencies, including extensive rules and regulations governing transportation, transmission and sale of energy commodities as well as the discharge of materials into the environment or otherwise relating to environmental protection. Compliance with these regulations requires general and administrative, capital and operating expenditures including those related to monitoring,

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pollution control equipment, emission fees and permitting at various operating facilities and remediation obligations. In addition, the United States Congress has before it a number of bills that could impact regulations or impose new regulations applicable to us and our subsidiaries. We cannot predict the outcome of these bills or other regulatory developments or the effects that they might have on our business.

Energy Policy Act of 2005. The Energy Policy Act of 2005 (EPACT) was signed into law on August 8, 2005. Title XII of EPACT (Electricity) created new legislation which deals with various matters impacting the power industry, including reliability of the bulk power system; transmission congestion, and transmission structure siting and modernization; the repeal of PUHCA; and prohibition of energy market manipulation, with enhanced FERC authority to prohibit market manipulation, including enhanced penalty authority. The FERC has implemented and is considering a number of related regulations to implement EPACT that may impact, among other things, requirements for reliability, QFs, transmission information availability, transmission congestion, security constrained dispatch, energy market transparency, energy market manipulation and behavioral rules.

Illinois Resource Procurement Auction. In January 2006, the ICC approved a resource procurement auction as the process by which utilities will procure power beginning in 2007. Under the ICC s Orders, the first auction will occur in September 2006 and would likely cover substantially all of the retail needs of the largest electric utilities in Illinois (Commonwealth Edison Company, and the three Ameren Illinois utilities: AmerenIP, AmerenCIPS and AmerenCILCO). Subsequent annual auctions would be held with the goal of ensuring adequate resources are under contract to serve Illinois retail needs. There continue to be challenges to the auction process. Therefore, there is a possibility of political, legislative, judicial and/or regulatory actions over the next several months that could alter substantially, or even eliminate altogether, the auctions. Given these uncertainties, the effect of the final process that will be used in Illinois cannot be predicted at this time.

Clean Air Mercury Rule. In March 2005, the Administrator of the Federal EPA signed a final Clean Air Mercury Rule (CAMR) that will require mercury emission reductions to be achieved from existing coal-fired electric generating units. This rule requires all states to adopt either the Federal EPA rule, or a state rule meeting the minimum requirements as outlined in CAMR. The Illinois EPA has proposed a state-specific rule (the Illinois Mercury Rule) that would require larger percent reductions in mercury emissions on a significantly shorter timeframe than the CAMR would require. We, along with most other owners of Illinois coal-fired electric generating units, are disputing the Illinois Mercury Rule in proceedings before the Illinois Pollution Control Board (IPCB). The rule was accepted by the IPCB under the fast track rulemaking procedures of Section 28.5 of the Illinois Environmental Protection Act; however, the Circuit Court for Sangamen County, Illinois has issued an injunction against the use of the Section 28.5 rulemaking procedures. A new schedule for the rulemaking has not been determined. After hearings are completed, IPCB will transmit the proposed rule to the Joint Committee on Administrative Rules (JCAR) , who will make the final decision. Various state legislative and regulatory bodies may be considering other legislation or rules that could impact current regulations or impose new regulations applicable to us and our subsidiaries. We cannot predict the outcome of these legislative and other regulatory developments, or the effects that they might have on our business.

Roseton State Pollutant Discharge Elimination System Permit. Roseton s SPDES Permit was issued for a five-year term in 1987. Prior to expiration of the permit, Central Hudson Gas & Electric (the former plant owner), filed a timely and sufficient application to renew the SPDES Permit. Under New York State law, when a timely and sufficient application for renewal is filed before a SPDES Permit expires, the permit is extended by operation of law until final action is taken on the renewal application. In April 2005, the NYSDEC issued to DNE a draft SPDES Permit (the Draft SPDES Permit) for the Roseton plant. The Draft SPDES Permit requires the facility to manage actively its water intake to reduce impingement mortality of fish by 85% and to reduce entrainment mortality of aquatic organisms including juvenile fish, larvae and fish eggs by 70% during the first two years of the renewal term, and by 80% thereafter.

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In July 2005, a public hearing was held to receive comments on the Draft SPDES Permit. Three organizations filed petitions for party status in the permit renewal proceeding, Riverkeeper, Inc., Natural Resource Defense Council, Inc. and Scenic Hudson, Inc. The Petitioners are seeking to impose a permit requirement that the Roseton plant install a closed cycle cooling system in order to reduce the volume of water withdrawn from the Hudson River, thus reducing entrainment and impingement of aquatic organisms and fish. The Petitioners claim that only a closed cycle cooling system meets the Clean Water Act s requirement that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts from the facility s cooling water intake structures. Currently, the Draft SPDES Permit does not require installation of a closed cycle cooling system; however, it does require entrainment and impingement mortality reductions that exceed the best technology available requirements of the USEPA regulations applicable to existing facilities. We expect that the adjudicatory hearing on the Draft SPDES Permit will be held in the fall of 2006. We believe that the Petitioners claims are without merit, and we plan to oppose those claims vigorously. Given the high cost of installing a closed cycle cooling system, an adverse result in this proceeding could have a material adverse effect on our financial condition, results of operations and cash flows.

Danskammer State Pollutant Discharge Elimination System Permit. Danskammer s SPDES Permit was issued for a five-year term in 1987. Prior to the expiration of the permit, Central Hudson Gas & Electric (the former plant owner), filed an application to renew the SPDES Permit. We believe that application was timely and sufficient. Under New York State law, when a timely and sufficient application for renewal is filed before a SPDES Permit expires, the permit is extended by operation of law until final action is taken on the renewal application. In November 2002, several environmental groups filed suit in the Supreme Court of the State of New York seeking, among other things, a declaratory judgment that the Danskammer SPDES Permit had expired because of alleged deficiencies in the renewal application process. In August 2004, the Court ruled that the SPDES Permit for our Danskammer facility was void, but stayed the enforcement of the decision pending further review by the Court or by the Appellate Division. In April 2006, the Appellate Division reversed the trial court and dismissed the case. The Court ruled that the environmental groups challenges to the extension of the SPDES Permit were barred by the applicable statute of limitations.

We are continuing to seek renewal of our water intake and discharge permit in proceedings before the NYSDEC. The Draft SPDES Permit was issued in January 2005 and an adjudicatory hearing was scheduled for the fall of 2005. The Petitioners, Riverkeeper, Inc., Natural Resource Defense Council, Inc. and Scenic Hudson, Inc., seek to impose a permit requirement that the Danskammer plant install a closed cycle cooling system in order to reduce the volume of water withdrawn from the Hudson River, thus reducing entrainment and impingement. Petitioners claim that only a closed cycle cooling system meets the Clean Water Act s requirement that the location, design, construction and capacity of cooling water intake structures reflect best technology available for minimizing adverse environmental impacts from the facility s cooling water intake structures. The Draft SPDES Permit does not require installation of a closed cycle cooling system; however, it does require entrainment and impingement mortality reductions that exceed the best technology available requirements of the USEPA regulations applicable to existing facilities.

A formal evidentiary hearing was held in November and December 2005 and post-hearing briefing was completed in March 2006. The Commissioner s decision on the permit renewal is due on May 19, 2006. We believe that Petitioners claims are without merit and we have vigorously opposed those claims. Given the high cost of installing a closed cycle cooling system, an adverse result in this proceeding could have a material adverse effect on our financial condition, results of operations and cash flows.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

FERC Market-Based Rate Authority. FERC-approved market-based rate authority allows those granted such authority to sell power at negotiated rates through the bilateral market or within an organized energy market, conditioned on periodic re-review. On June 16, 2005, FERC issued an order accepting the updated market power analyses submitted by Sithe Energies and Dynegy. Our next triennial market power analysis is due June 16, 2008. Accordingly, these entities have continuously had market-based rate authority.

We are also subject to the FERC s market behavior rules, which emerged from its consideration of market manipulation in the Western markets. The rules, which were promulgated in 2003 for the purpose of prohibiting manipulation in the wholesale electricity and natural gas markets subject to FERC s jurisdiction, are incorporated in the tariffs of the various Dynegy entities with market based rates for wholesale power and apply to sales in organized and bilateral markets and spot markets, as well as long-term sales (as well as to the wholesale sale of natural gas under a blanket marketing certificate). The remedies for violating the rules could include disgorgement of unjust profits or suspension or revocation of the authority to sell at market-based rates and penalties. Pursuant to the Energy Policy Act of 2005, FERC recently finalized new regulations prohibiting energy market manipulation, which regulations are patterned after the language of the SEC s Rule 10b-5. Subsequently, FERC rescinded two of the six market behavior rules (as they are covered in FERC s new regulations prohibiting market manipulation or other FERC standards) and codified the remaining four in its regulations. The extent to which these regulations will affect the costs or other aspects of our operations is uncertain. However, we believe that our entities subject to the regulations are currently in compliance.

Note 12 Employee Compensation, Savings and Pension Plans

We have various defined benefit pension plans and post-retirement benefit plans, which are more fully described in Note 20 Employee Compensation, Savings and Pension Plans beginning on page F-73 of our Form 10-K/A.

Components of Net Periodic Benefit Cost. The components of net periodic benefit cost were:

	Pension Benefits		Other Benefits	
	Quarter Ended March 31,			
	2006	2005	2006	2005
	(in millions)			
Service cost benefits earned during period	$ 2	$ 3	$ 1	$ 1
Interest cost on projected benefit obligation	2	2	1	1
Expected return on plan assets	(2)	(2)		
Recognized net actuarial loss	1	1		
Net periodic benefit cost	$ 3	$ 4	$ 2	$ 2
Additional cost due to curtailment	2			
Total net periodic benefit cost	$ 5	$ 4	$ 2	$ 2

The curtailment charge was accrued at December 31, 2005 in other long-term liabilities on our unaudited condensed consolidated balance sheets.

Contributions. In our Form 10-K/A, we reported that we expected to contribute approximately $17 million to our pension plans, $14 million of which we expect to pay in September 2006, and less than $1 million to our other postretirement benefit plans in 2006. As of March 31, 2006, we made less than $1 million in contributions.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

Note 13 Income Taxes

Effective Tax Rate. The income taxes included in continuing operations were as follows:

	Three Months Ended March 31,	
	2006	2005
	(in millions, except rates)	
Income tax benefit (expense)	$ (3)	$ 174
Effective tax rate	150%	37%

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income or loss, except for significant unusual or extraordinary transactions. Income taxes for significant unusual or extraordinary transactions are computed and recorded in the period that the specific transaction occurs. During 2006, our overall effective tax rate on continuing operations was different than the statutory rate of 35% due primarily to a reduction of AMT credits due to the settlement of prior year tax audits and state income taxes. During 2005, our overall effective tax rate on continuing operations was different than the statutory rate of 35% due primarily to the nondeductible portion of the charge associated with the shareholder litigation settlement, offset by changes in the valuation allowances.

Note 14 Segment Information

We report the results of our power generation business as three separate geographical segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also separately report the results of our former NGL and CRM business segments because of the diversity among their respective operations. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization. Certain general and administrative expenses were allocated to our reporting segments prior to January 1, 2006. Beginning January 1, 2006, all direct general and administrative expenses are included in Other and Eliminations, unless they are specifically identified with the respective segment.

Pursuant to EITF Issue 02-03, all gains and losses on third party energy trading contracts in the CRM segment, whether realized or unrealized, are presented net in the consolidated statements of operations. For the purpose of the segment data presented below, intersegment transactions between CRM and our other segments are presented net in CRM intersegment revenues but are presented gross in the intersegment revenues of our other segments, as the activities of our other segments are not subject to the net presentation requirements contained in EITF Issue 02-03. If transactions between CRM and our other segments result in a net intersegment purchase by CRM, the net intersegment purchases and sales are presented as negative revenues in CRM intersegment revenues. In addition, intersegment hedging activities are presented net pursuant to SFAS No. 133.

Our former natural gas liquids operations comprise the NGL segment and are included in discontinued operations. Results associated with the former DGC segment are included in discontinued operations in Other and Eliminations due to the sale of our communications businesses. Reportable segment information, including intercompany transactions accounted for at prevailing market rates, for the three months ended March 31, 2006 and 2005 is presented below:

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

Dynegy s Segment Data for the Quarter Ended March 31, 2006

(in millions)

	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other and Eliminations	Total
Unaffiliated revenues:							
Domestic	$ 256	$ 133	$ 111	$ 40	$	$	$ 540
Other		60					60
	256	193	111	40			600
Intersegment revenues		(1)		1			
Total revenues	$ 256	$ 192	$ 111	$ 41	$	$	$ 600
Depreciation and amortization	$ (40)	$ (6)	$ (6)	$	$	$ (8)	$ (60)
Operating income (loss)	$ 98	$ 26	$ (13)	$ 14	$	$ (47)	$ 78
Earnings from unconsolidated investments			2				2
Other items, net		2		1		17	20
Interest expense							(98)
Income from continuing operations before income taxes							2
Income tax expense							(3)
Loss from continuing operations							(1)
Income from discontinued operations, net of taxes							1
Cumulative effect of change in accounting principle, net of taxes							1
Net income							$ 1
Identifiable assets:							
Domestic	$ 4,587	$ 1,412	$ 830	$ 608	$ 30	$ 1,285	$ 8,752
Other		15	5	98			118
Total	$ 4,587	$ 1,427	$ 835	$ 706	$ 30	$ 1,285	$ 8,870
Unconsolidated investments	$	$	$ 6	$	$	$	$ 6
Capital expenditures	$ (11)	$ (3)	$ (3)	$	$	$ (1)	$ (18)

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

Dynegy s Segment Data for the Quarter Ended March 31, 2005

(in millions)

	Power Generation							
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	REG	Other and Eliminations	Total
Unaffiliated revenues:								
Domestic	$ 214	$ 159	$ 72	$ 63	$	$	$	$ 508
Other				(46)				(46)
	214	159	72	17				462
Intersegment revenues	1	2	(12)	9				
Total revenues	$ 215	$ 161	$ 60	$ 26	$	$	$	$ 462
Depreciation and amortization	$ (37)	$ (5)	$ (5)	$ (1)	$	$	$ (7)	$ (55)
Operating income (loss)	$ 61	$ 11	$ (12)	$ (192)	$	$	$ (253)	$ (385)
Earnings from unconsolidated investments			3					3
Other items, net				1			2	3
Interest expense								(89)
Loss from continuing operations before income taxes								(468)
Income tax benefit								174
Loss from continuing operations								(294)
Income from discontinued operations, net of taxes								32
Net loss								$ (262)
Identifiable assets:								
Domestic	$ 5,076	$ 1,562	$ 1,062	$ 1,245	$ 1,596	$ 16	$ 200	$ 10,757
Other			5	223				228
Total	$ 5,076	$ 1,562	$ 1,067	$ 1,468	$ 1,596	$ 16	$ 200	$ 10,985
Unconsolidated investments	$ 62	$	$ 277	$	$ 77	$	$	$ 416
Capital expenditures	$ (37)	$ (3)	$	$	$ (10)	$	$ (4)	$ (54)

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended March 31, 2006 and 2005

Note 15 Subsequent Events

On April 12, 2006, we completed the SPN Tender Offer in which we purchased $150 million of our $225 million 2008 Notes, substantially all of our $625 million 2010 Notes and all of our $900 million 2013 Notes. Please see Note 7 Debt Second Priority Senior Secured Notes for further discussion.

On April 12, 2006, we issued $750,000,000 aggregate principal amount of our New Senior Notes in the Senior Notes Offering. Please see Note 7 Debt Senior Unsecured Notes for further discussion.

On April 19, 2006, we entered into the Fourth Senior Secured Credit Facility. The Fourth Senior Secured Credit Facility amended DHI s former credit facility, upsized the revolving credit facility to $470 million and added a $200 million term facility. Please see Note 7 Debt Senior Secured Credit Facility for further discussion.

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DYNEGY INC.

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

For the Interim Periods Ended March 31, 2006 and 2005

Item 2 MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read together with the unaudited condensed consolidated financial statements and the notes thereto included in this report and with the audited consolidated financial statements and the notes thereto included in our Form 10-K/A.

GENERAL

We are a holding company and conduct substantially all of our business operations through our subsidiaries. Our current business operations are focused primarily on the power generation sector of the energy industry. We report the results of our power generation business as three separate segments in our consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also separately report the results of our CRM business, which primarily consists of our remaining power tolling arrangement (excluding the Sithe toll which is in GEN-NE and is an intercompany agreement) as well as our physical gas supply contracts, gas transportation contracts and remaining gas, power and emission trading positions. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our consolidated financial statements. Our consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization.

Recent Developments

Sterlington Termination. On March 7, 2006, we completed the termination of the Sterlington long-term wholesale power tolling contract with Quachita Power LLC. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sterlington Contract Termination for further discussion.

Exchange of Ownership Interests. On March 31, 2006, we completed our acquisition of NRG s 50% ownership interest in the entity that owns the Rocky Road power plant, a 364-megawatt natural gas-fired peaking facility near Chicago (of which Dynegy already owned 50%), and the sale to NRG of our 50% ownership interest in a joint venture between us and NRG which has ownership in power plants in southern California. As a result of the two transactions, we received net cash proceeds of approximately $160 million from NRG. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations West Coast Power for further discussion.

Liability Management. During March and April 2006, we initiated several transactions to utilize proceeds from the October 2005 sale of DMSLP consistent with our key objectives. These key objectives were: (i) reduce existing debt obligations, (ii) reduce interest expense, (iii) reduce near- to medium-term debt maturities, (iv) maintain adequate liquidity and (v) enhance capital structure flexibility. We believe that these transactions will better align our capital structure with the inherently cyclical nature of our industry and enhance our ability to benefit from the anticipated future market recovery and to access the capital markets. To that end, we accomplished the following:

On March 6, 2006, we entered into a third amended and restated credit agreement (the Third Senior Secured Credit Facility). The Third Senior Secured Credit Facility replaced DHI s former cash collateralized letter of credit facility with a $400 million revolving credit facility thereby permitting the return to DHI of $335 million plus accrued interest in cash collateral securing the former letter of credit facility (the Cash Collateral Return).

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On April 12, 2006, we completed a tender offer and consent solicitation (the SPN Tender Offer) in which we purchased $150 million of our $225 million outstanding Second Priority Senior Secured Floating Rate Notes due 2008 (the 2008 Notes), substantially all of our $625 million 9.875% Second Priority Senior Secured Notes due 2010 (the 2010 Notes) and all of our $900 million 10.125% Second Priority Senior Secured Notes due 2013 (the 2013 Notes and, collectively with the 2008 Notes and the 2010 Notes, the Second Priority Notes).

Concurrent with the closing of the SPN Tender Offer, we issued $750,000,000 aggregate principal amount of 8.375% Senior Unsecured Notes due 2016 (the New Senior Notes) in a private offering (the Senior Notes Offering). We used proceeds from the Senior Notes Offering, together with cash on hand, to fund the SPN Tender Offer.

On April 19, 2006, we entered into a fourth amended and restated credit agreement (the Fourth Senior Secured Credit Facility). The Fourth Senior Secured Credit Facility amended DHI s former credit facility, upsized the revolving credit facility to $470 million and added a $200 million letter of credit facility funded with term loan proceeds.

Additionally, we are currently in negotiations with Chevron, our largest common stock holder and holder of all of our outstanding Series C Convertible Preferred Stock (Series C Preferred), regarding our possible redemption of all of the Series C Preferred. The Series C Preferred is convertible into shares of our common stock in accordance with its terms. We have included the underlying shares of Class A common stock in our fully diluted earnings per share calculations in accordance with GAAP. If we and Chevron reach definitive agreements on such redemption, which could occur in the near term, we may finance the redemption, in part, by issuing shares of our Class A common stock in a registered public offering. If so, we would not expect the number of shares to be issued in such an offering to exceed the number of shares into which the Series C Preferred is convertible - approximately 69,200,000. Any remaining amounts required to finance the redemption would be expected to come from cash on hand, proceeds from asset sales or other capital-raising activities. As a result, if both the equity offering and redemption occurred, we would not expect that more shares of our common stock would be outstanding on a fully diluted basis than are outstanding today. If consummated, these transactions would eliminate the preferred dividend requirements on the Series C Preferred and further simplify our capital structure.

The receptiveness of the capital markets to a public offering cannot be assured and may be negatively impacted by, among other things, our non-investment grade credit ratings, significant debt maturities, long-term business prospects and other factors beyond our control. Any issuance of equity could have other effects as well, including potential shareholder dilution. Further, our ability to issue debt securities is limited by our financing agreements, including our credit facility. Please read Note 7 Debt for further discussion.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Debt Obligations

During 2006, we continued our efforts to reduce our outstanding debt and extend our maturity profile, evidenced by the transactions discussed under Liability Management above. Please read Note 7 Debt for further discussion.

We may further reduce our outstanding debt if we exercise our contractual option to call for redemption, on or after July 15, 2006, any remaining outstanding 2008 Notes at the redemption price of $1,030.00 per $1,000 principal amount thereof, plus accrued and unpaid interest to the redemption date. Any such notice, if given, will be given in accordance with the applicable provisions of the indenture. We may ultimately determine not to effect the redemption of the remaining outstanding 2008 Notes. Pursuant to the indenture governing the Second Priority Notes, the 2010 Notes are redeemable at our option on or after July 15, 2007 at the redemption price of $1,049.38 per $1,000 principal amount thereof, plus accrued and unpaid interest to the redemption date.

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Collateral Postings

We continue to use a significant portion of our capital resources, in the form of cash and letters of credit, to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade credit ratings and counterparties views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. The following table summarizes our consolidated collateral postings to third parties by segment at May 4, 2006, March 31, 2006 and December 31, 2005:

	May 4, 2006	March 31, 2006	December 31, 2005
		(in millions)	
By Segment:			
Generation	$ 160	$ 168	$ 280
Customer risk management	75	69	91
Other	8	8	10
Total	$ 243	$ 245	$ 381
By Type:			
Cash (1)	$ 68	$ 67	$ 122
Letters of Credit	175	178	259
Total	$ 243	$ 245	$ 381

(1) Cash collateral consists of either cash deposits to cover physical deliveries or liabilities on mark-to-market positions or prepayments for commodities or services that are in advance of normal payment terms.

The decrease in collateral postings from December 31, 2005 to March 31, 2006 is primarily due to a return of collateral postings of approximately $112 million in our generation business and $22 million in our customer risk management business. This decrease is primarily a result of decreases in commodity prices since the end of 2005, as well as rolloffs of our hedging positions. In addition, the collateral posted on behalf of West Coast Power decreased by approximately $25 million in anticipation of the sale of our 50% interest in West Coast Power to NRG, completed on March 31, 2006. As of March 31 and May 4, 2006, we posted approximately $21 million and $6 million, respectively, of collateral on behalf of West Coast Power, all of which is offset by cash collateral received from West Coast Power. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations West Coast Power for further discussion of the West Coast Power sale.

Going forward, we expect counterparties collateral demands to continue to reflect changes in commodity prices, including seasonal changes in weather-related demand, as well as their views of our creditworthiness. Considering our credit ratings and current commodity price estimates, specifically as prices relate to fuel purchases and power hedging activities, we estimate that collateral requirements will be approximately $300 million at year-end 2006. We believe that we have sufficient capital resources to satisfy counterparties collateral demands, including those for which no collateral is currently posted, for the foreseeable future.

Disclosure of Contractual Obligations and Contingent Financial Commitments

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

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Our contractual obligations and contingent financial commitments have changed since December 31, 2005, with respect to which information is included in our Form 10-K/A. As a result of the termination of the Sterlington long-term wholesale power tolling contract with Quachita Power, capacity payments of up to approximately $744 million have been eliminated. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Sterlington Contract Termination for further discussion.

As of March 31, 2006, there were no other material changes to our contractual obligations and contingent financial commitments since December 31, 2005.

Dividends on Preferred and Common Stock

Dividend payments on our common stock are at the discretion of our Board of Directors. We did not declare or pay a dividend on our common stock for the first quarter 2006 and do not foresee a declaration of dividends in the near term.

We accrue dividends on the Series C Preferred at a rate of 5.5% per annum. These dividends are payable in February and August of each year, but we may defer payments for up to 10 consecutive semi-annual periods. If the holder of the Series C Preferred does not receive the full dividends to which it is entitled on any specified dividend payment date, then such unpaid dividends will be deferred, will cumulate and will accrue additional dividends at the rate of 5.5% per annum. In February 2006, we made our semi-annual dividend payment of $11 million. Please read Note 15 Redeemable Preferred Securities beginning on page F-55 of our Form 10-K/A for further discussion. Currently we are in negotiations with Chevron regarding possible near-term redemption of the Series C Preferred. Please read Note 8 Related Party Transactions for further discussion.

Unless we have sufficient liquidity and assuming the Series C Preferred remains outstanding, we may defer future payment of dividends on the Series C Preferred.

Internal Liquidity Sources

Our primary internal liquidity sources are cash flows from operations, cash on hand and available capacity under our Fourth Senior Secured Credit Facility, which is scheduled to mature in April 2009.

Current Liquidity. The following table summarizes our consolidated revolver capacity and liquidity position at May 4, 2006, March 31, 2006 and December 31, 2005:

	May 4, 2006	March 31, 2006	December 31, 2005
		(in millions)	
Total revolver capacity	$ 470(1)	$ 400(1)	$
Total additional letter of credit capacity net of 3% reserve requirement	194		325
Outstanding letters of credit under revolving credit facility	(175)	(178)	(259)
Unused revolver capacity	489	222	66
Cash	524(2)(3)	1,691(2)	1,549(2)
Total available liquidity	$ 1,013	$ 1,913	$ 1,615

(1) In March and April 2006, we amended and restated the credit facility. Please see Note 7 Debt for further discussion.
(2) The May 4, 2006, March 31, 2006 and December 31, 2005 amounts include approximately $19 million, $22 million and $21million, respectively, of cash that remains in Europe and $20 million, $18 million and $19 million, respectively, of cash that remains in Canada.
(3) The decrease in cash balance since March 31, 2006 was primarily due to the payments associated with our SPN Tender Offer, offset by the proceeds from the issuance of our Senior Unsecured Notes. Please read Note 7 Debt for further discussion.

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Cash Flows from Operations. We had operating cash outflows of $311 million for the three months ended March 31, 2006. This consisted of $192 million in operating cash flows from our power generation business, offset by $368 million of cash outflows relating to our customer risk management business and $135 million of cash outflows relating to corporate-level expenses. Please read Results of Operations Operating Income (Loss) and Cash Flow Disclosures for further discussion of factors impacting our operating cash flows for the periods presented.

For 2006, our estimate of operating cash outflows totals $220 to $110 million. This estimate, which is based on quoted forward commodity price curves as of April 11, 2006 and is subject to change based on a number of factors, many of which are beyond our control, reflects $530 to $630 million in estimated operating cash flows from our generation business, offset by estimated cash outflows of $390 million from our customer risk management business and $360 to $350 million in corporate-level expenses, including $335 million of interest.

Over the longer term, our operating cash flows also will be impacted by, among other things, our ability to manage tightly our operating costs, including costs for fuel and maintenance. Our ability to achieve targeted cost savings in the face of industry-wide increases in labor and benefits costs, together with changes in commodity prices, will impact our future operating cash flows. Please read Results of Operations 2006 Outlook for further discussion.

Cash on Hand. At May 4, 2006 and March 31, 2006, we had cash on hand of $524 million and $1,691 million, respectively, as compared to $1,549 million at the end of 2005. This increase in cash on hand to March 31, 2006 as compared to the end of 2005 is primarily attributable to (i) the return of $335 million of cash collateral plus accrued interest posted for the former Third Amended and Restated Credit Facility and (ii) proceeds of $205 million received from the sale of our 50% ownership interest in the West Coast Power power plants to NRG. This was offset by (i) payment of $40 million, net of cash acquired of $5 million, to NRG for acquiring NRG s 50% ownership interest in the Rocky Road power plant and (ii) payment of $370 million to Quachita Power LLC to terminate the Sterlington long-term wholesale power tolling contract. The decrease in cash balance on May 4, 2006 from March 31, 2006 was primarily due to the payments associated with our SPN Tender Offer, offset by the proceeds from the issuance of our Senior Unsecured Notes. Please read Note 7 Debt for further discussion.

Revolver Capacity. In April 2006, we entered into the Fourth Senior Secured Credit Facility. The Fourth Senior Secured Credit Facility replaces our former Third Senior Secured Credit Facility. Please read Note 23 Subsequent Events beginning on page F-85 of our Form 10-K/A for further discussion of our former Third Senior Secured Credit Facility. This credit facility is scheduled to mature in April 2009 and is our primary credit facility. We currently have no drawn amounts under this facility, although as of May 4, 2006, we had $175 million in letters of credit issued under the facility. Our ability to borrow and/or issue letters of credit under a revolving credit facility could become increasingly important to our liquidity and financial condition, particularly if we are unable to generate operating cash flows relative to our substantial debt obligations and ongoing operating requirements. Please read Note 7 Debt for further discussion of our Fourth Senior Secured Credit Facility.

External Liquidity Sources

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

Asset Sale Proceeds. In March 2006, we completed our ownership exchange transaction with NRG Energy, Inc. which comprised our acquisition of NRG s 50% ownership interest in the entity that owns the Rocky Road power plant (of which Dynegy already owned 50%), and the sale to NRG of our 50% ownership interest in a joint venture between us and NRG which has ownership in power plants in southern California. As a result of the two transactions, we received net cash proceeds of approximately $160 million from NRG. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations West Coast Power for further discussion.

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Going forward, we will continue to evaluate our generation fleet based primarily on geographic location, fuel supply, market structure and market recovery expectations. Consistent with industry practice, we periodically consider divestitures of non-core generation assets where the balance of the factors described above suggests that such assets earnings potential is limited. Although we have not executed definitive agreements regarding the divestitures of any non-core assets, opportunities arise from time to time and, as a result, a divestiture could occur at any time.

Capital-Raising Transactions. As part of our ongoing efforts to develop a capital structure that is more closely aligned with the cash-generating potential of our asset-based business, which is subject to cyclical changes in commodity prices, we are continuing to explore additional capital-raising transactions both in the near- and long-term. The timing of any capital-raising transaction may be impacted by unforeseen events, such as strategic growth opportunities, legal judgments or regulatory requirements, which could require us to pursue additional capital in the near term. Please read Recent Developments above for discussion of a potential equity offering to fund the redemption of the Series C Preferred.

Conclusion

We have recently completed financing transactions designed to (i) reduce existing debt obligations, (ii) reduce interest expense, (iii) reduce near- to medium-term debt maturities, (iv) maintain adequate liquidity and (v) enhance capital structure flexibility. We believe that these transactions will better align our capital structure with the inherently cyclical nature of our industry and enhance our ability to benefit from the anticipated market recovery and to access the capital markets.

We intend to continue our efforts to manage costs and capital expenditures effectively. To that end, in December 2005, we announced a comprehensive plan to better align our corporate cost structure with our single line of business. The plan included headcount reductions and system changes, and has resulted in a reduction of our run-rate general and administrative expenses. Further, our generation assets are managed to require a relatively predictable level of maintenance capital expenditures without compromising the operational integrity of our facilities, allowing us to maintain our focus on being a reliable, low-cost producer of physical products and provider of services.

We believe that our efficient and scalable operations platform, together with our multi-fuel capabilities and regionally-focused presence, position us to benefit from opportunities that might arise in connection with any growth transactions, industry consolidations or other strategic activities. To achieve these strategic objectives, we expect to continue to develop opportunities that may expand our existing facilities, achieve operating efficiencies or pursue opportunistic and selective expansion of our generation portfolio. Please read Item 1A-Risk Factors for further discussion.

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

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RESULTS OF OPERATIONS

Overview. In this section, we discuss our results of operations, both on a consolidated basis and, where appropriate, by segment, for the three-month periods ended March 31, 2006 and 2005. At the end of this section, we have included our 2006 outlook for each segment.

We report the results of our power generation business as three separate segments in our unaudited condensed consolidated financial statements: (1) the Midwest segment (GEN-MW); (2) the Northeast segment (GEN-NE); and (3) the South segment (GEN-SO). We also separately report results of our CRM business, which primarily consists of our remaining power tolling arrangement as well as the physical gas supply contracts, gas transportation contracts and remaining gas, power and emission trading positions that remain from the third-party trading business that was substantially exited in 2002. The Sithe toll is reported in GEN-NE and is an intercompany agreement. Our unaudited condensed consolidated financial results also reflect corporate-level expenses such as general and administrative, interest and depreciation and amortization. Because of the diversity among their respective operations, we report the results of each business as a separate segment in our unaudited condensed consolidated financial statements. Certain general and administrative expenses were allocated to our reporting segments prior to January 1, 2006. Beginning January 1, 2006, all direct general and administrative expenses are included in Other and Eliminations, unless they are specifically identified with the respective segment. This change in allocation methodology is a result of our efforts to better align our corporate cost structure with a single line of business.

Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for the three-month periods ended March 31, 2006 and 2005, respectively:

Quarter Ended March 31, 2006

	Power Generation					
	GEN-MW	GEN - NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 98	$ 26	$ (13)	$ 14	$ (47)	$ 78
Earnings from unconsolidated investments			2			2
Other items, net		2		1	17	20
Interest expense						(98)
Income from continuing operations before income taxes						2
Income tax expense						(3)
Loss from continuing operations						(1)
Income from discontinued operations, net of taxes						1
Cumulative effect of change in accounting principle, net of taxes						1
Net income						$ 1

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Quarter Ended March 31, 2005

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 61	$ 11	$ (12)	$ (192)	$ (253)	$ (385)
Earnings from unconsolidated investments			3			3
Other items, net				1	2	3
Interest expense						(89)
Loss from continuing operations before income taxes						(468)
Income tax benefit						174
Loss from continuing operations						(294)
Income from discontinued operations, net of taxes						32
Net loss						$ (262)

The following table provides summary segmented operating statistics for the three months ended March 31, 2006 and 2005, respectively:

	Quarter Ended March 31, 2006	2005
GEN-MW		
Million Megawatt Hours Generated Gross and Net	5.4	5.0
Average On-Peak Market Power Prices ($/MWh):		
Cinergy (Cin Hub)	$ 49	$ 49
Commonwealth Edison (NI Hub)	$ 50	$ 49
GEN-NE		
Million Megawatt Hours Generated Gross and Net	1.0	2.0
Average On-Peak Market Power Prices ($/MWh):		
New York Zone G	$ 76	$ 70
New York Zone A	$ 60	$ 58
GEN-SO		
Million Megawatt Hours Generated Gross	1.4	1.9
Million Megawatt Hours Generated Net	1.1	1.4
Average On-Peak Market Power Prices ($/MWh):		
Southern	$ 55	$ 49
ERCOT	$ 56	$ 51
SP-15	$ 58	$ 56
Average natural gas price Henry Hub ($/MMBtu) (1)	$ 7.75	$ 6.39

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

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The following tables summarize significant items on a pre-tax basis, affecting net loss for the periods presented.

	Quarter Ended March 31, 2006						
	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other	Total
				(in millions)			
Legal and settlement charges	$	$	$	$ (15)	$	$	$ (15)
Total	$	$	$	$ (15)		$	$ (15)

	Quarter Ended March 31, 2005						
	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other	Total
				(in millions)			
Discontinued operations	$	$	$	$ 4	$ 46	$	$ 50
Legal and settlement charges						(222)	(222)
Independence toll settlement charge				(183)			(183)
Total	$	$	$	$ (179)	$ 46	$ (222)	$ (355)

Operating Income (Loss)

Operating income was $78 million for the three months ended March 31, 2006, compared to a loss of $385 million for the three months ended March 31, 2005.

Power Generation Midwest Segment. Operating income for GEN-MW was $98 million for the three months ended March 31, 2006, compared to $61 million for the three months ended March 31, 2005. GEN-MW results for the three months ended March 31, 2005 included general and administrative expenses of $8 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please see Results of Operations Operating Income (Loss) Other for a consolidated discussion of general and administrative expenses.

Results from our coal-fired generating units increased to $135 million for the three months ended March 31, 2006 from $107 million for the three months ended March 31, 2005. This improvement was driven by an 8% increase in generated volumes, up from 5.0 million MWh for the first quarter 2005 to 5.4 million MWh for the same period in 2006. Average actual on-peak prices in NI Hub/ComEd pricing region increased from $49 per MWh in first quarter 2005 to $50 per MWh for the first quarter 2006. However, we realized higher power prices in the first quarter 2006 as we settled forward power sales, which had been entered into during the fourth quarter 2005.

GEN-MW s results for the first three months of 2006 include no significant mark-to-market income, compared with losses of $4 million for the three months ended March 31, 2005. This is primarily related to options and other transactions that economically hedged our generation assets, and were not accounted for as cash flow hedges.

Results for our gas-fired peaking facilities in GEN-MW improved by $5 million, increasing from a loss of $2 million for the first three months of 2005 to positive earnings of $3 million for the same period in 2006. This improvement was the result of higher volume as the MISO increased dispatch of these units during first quarter 2006 to maintain system reliability.

Depreciation expense increased slightly, from $37 million in 2005 to $40 million in 2006 as a result of capital projects placed into service in 2005. This was primarily the conversion of the Havana facility to burn PRB coal.

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Power Generation Northeast Segment. Operating income for GEN-NE was $26 million for the three months ended March 31, 2006, compared to $11 million for the three months ended March 31, 2005. GEN-NE for the three months ended March 31, 2005 included general and administrative expenses of $6 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please see Results of Operations Operating Income (Loss) Other for a consolidated discussion of general and administrative expenses.

Results from our Northeast facilities were $32 million for the three months ended March 31, 2006, compared with $22 million for three months ended March 31, 2005.

Improved results for 2006 are driven primarily by addition of the Independence facility in February 2005. Independence contributed results of $12 million for the first quarter 2006, compared with $2 million for February and March 2005. Although generated volumes from our Independence facility decreased year over year, we received a benefit of approximately $9 million from realization of higher power prices in the first quarter 2006, as we settled forward power sales which had been entered into in the fourth quarter 2005.

Results for our Roseton and Danskammer facilities remained largely unchanged. Average on-peak prices for Zone G, the market served by these two facilities, increased from $70 per MWh in 2005 to $76 per MWh in 2006. However, this price increase was largely offset by a volume decrease, caused by compressed spark spreads at our Roseton facility, where volumes fell by 0.7 million MWh from first quarter 2005 as compared to first quarter 2006. Generated volumes at our Danskammer facility decreased by 0.2 million MWh from first quarter 2005 to first quarter 2006. Results from our Roseton and Danskammer facilities also increased by $10 million as a result of the opportunistic sale of emissions credits that will not be required for the near-term operations of our facilities. However, this increase was offset by net mark-to-market losses of $6 million for the first quarter 2006, related to financial transactions not designated as cash flow hedges. First quarter 2005 results included mark-to-market gains of $3 million.

Depreciation expense for GEN-NE increased from $5 million to $6 million, as the result of adding the Independence facility in February 2005.

Power Generation South Segment. Operating loss for GEN-SO was $13 million for three months ended March 31, 2006, compared to a loss of $12 million for three months ended March 31, 2005. GEN-SO for the three months ended March 31, 2005, included general and administrative expenses of $3 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please see Results of Operations Operating Income (Loss) Other for a consolidated discussion of general and administrative expenses.

Results from our ERCOT facility decreased by $6 million, from a loss of $4 million in 2005 to a loss of $10 million in 2006. Power prices increased by 10% from 2005 to 2006. This was offset by the negative effect of higher gas prices on the steam contract at our CoGen Lyondell cogeneration facility in 2006. In addition, we were able to capture additional revenue for ancillary services provided to ERCOT in first quarter 2005 at levels that we were not asked to provide in first quarter 2006.

Results from our southeast peaker assets increased slightly from negligible earnings in first quarter 2005 to earnings of $1 million in the same period in 2006 as a result of additional capacity sales from our Rockingham facility.

Depreciation expense increased slightly from $5 million to $6 million, as a result of additional capital spending.

CRM. Operating income for the CRM segment was $14 million for the three months ended March 31, 2006, compared to operating loss of $192 million for the three months ended March 31, 2005. 2006 income was driven primarily by mark-to-market gains on our legacy emissions positions, offset by a $15 million increase in legal reserves resulting from additional activities during the period that negatively affected management s assessment of the probable and estimable losses associated with the applicable proceedings.

Results for 2005 were negatively impacted by a $183 million charge associated with the acquisition of Sithe Energies. Prior to the acquisition, Independence held a power tolling contract and a gas supply agreement with our CRM segment. Upon completion of the purchase, these contracts became intercompany agreements reported under our GEN-NE segment, and were effectively eliminated on a consolidated basis, resulting in the $183 million charge upon completion of the acquisition. In addition, this segment s first quarter 2005 results reflect the negative impact of fixed payments on our remaining power tolling arrangements in excess of realized margins on power generated and sold.

Other. Other operating loss was $47 million for the quarter ended March 31, 2006, compared to a loss of $253 million for the quarter ended March 31, 2005. Results for first quarter 2006 include approximately $36 million of general and administrative expenses, including costs related to our business segments, which prior to first quarter 2006 were included in the individual segments. Results for the three months ended March 31, 2005 included general and administrative expenses of $246 million. Please see below for a consolidated discussion of general and administrative expenses.

Consolidated general and administrative expenses decreased from $263 million for the three months ended March 31, 2005 to $51 million for the three months ended March 31, 2006, primarily due to a $222 million charge associated with settlement of our shareholder class action litigation in 2005, offset by the $15 million legal reserve recorded in 2006 in our CRM segment.

Earnings from Unconsolidated Investments

The $2 million earnings reported from unconsolidated investments for the three months ended March 31, 2006 included the GEN-SO investment in Black Mountain. The $3 million earnings reported for the three months ended March 31, 2005 includes results from GEN-SO investments in both Black Mountain and West Coast Power.

Other Items, Net

Other items, net totaled $20 million of income for the three months ended March 31, 2006, compared to $3 million of income for the three months ended March 31, 2005. The increase is primarily associated with higher interest income in 2006 resulting from higher cash balances and higher interest rates.

Interest Expense

Interest expense totaled $98 million for the three months ended March 31, 2006, compared to $89 million for the three months ended March 31, 2005. The increase is primarily attributable to increases in LIBOR and interest on Sithe debt for the entire first quarter 2006 as compared to two months of first quarter 2005 as a result of our acquisition of Sithe in February 2005.

Income Tax Benefit (Expense)

We reported an income tax expense from continuing operations of $3 million for the three months ended March 31, 2006, compared to an income tax benefit from continuing operations of $174 million for the three months ended March 31, 2005. The 2006 effective tax rate was 150%, compared to 37% in 2005. Our overall effective tax rate on continuing operations was different than the statutory rate of 35% due primarily to a reduction of AMT credits due to the settlement of prior year tax audits and state income taxes in 2006 and due primarily to the nondeductible portion of the charge associated with the shareholder litigation settlement, offset by changes in the valuation allowances in 2005.

Discontinued Operations

Income From Discontinued Operations Before Taxes. Discontinued operations include DMSLP in our NGL segment and our U.K. CRM business and U.K. natural gas storage assets in the CRM segment.

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The following summarizes the activity included in income from discontinued operations:

Three Months Ended March 31, 2006

	U.K. CRM	NGL (in millions)	Total
Operating income included in income from discontinued operations	$	$ 1	$ 1
Other items, net included in income from discontinued operations	1		1
Income from discontinued operations before taxes			2
Income tax expense			(1)
Income from discontinued operations			$ 1

Three Months Ended March 31, 2005

	U.K. CRM	NGL (in millions)	Total
Operating income included in income from discontinued operations	$	$ 59	$ 59
Earnings from unconsolidated investments included in income from discontinued operations		2	2
Other items, net included in income from discontinued operations	4	(4)	
Interest expense included in income from discontinued operations			(11)
Income from discontinued operations before taxes			50
Income tax expense			(18)
Income from discontinued operations			$ 32

As further discussed in Note 3 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids, on October 31, 2005, we completed the sale of DMSLP. As a result of the sale, and as required by Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we have reclassified the operations related to DMSLP, which comprised of the remaining operations of our NGL segment, from continuing operations to discontinued operations.

During the three months ended March 31, 2006, pre-tax income from discontinued operations of $2 million ($1 million after-tax) included $1 million in pre-tax income attributable to NGL. During the three months ended March 31, 2005, pre-tax income from discontinued operations of $50 million ($32 million after-tax) included $46 million in pre-tax income attributable to NGL.

In accordance with EITF Issue 87-24, Allocation of Interest to Discontinued Operations, we have allocated interest expense to discontinued operations associated with debt instruments that were required to be paid upon the sale of DMSLP. Interest expense included in income from discontinued operations, which includes interest incurred on our former term loan and our former Generation facility debt, totaled zero and $11 million during the three months ended March 31, 2006 and 2005, respectively.

Income Tax Expense From Discontinued Operations. We recorded an income tax expense from discontinued operations of $1 million during the three months ended March 31, 2006, compared to an income tax expense from discontinued operations of $18 million during the three months ended March 31, 2005. These amounts reflect effective rates of 50% and 36%, respectively. In general, differences between these effective rates and the statutory rate of 35% result primarily from the effect of certain foreign and state income taxes and permanent differences attributable to book-tax differences.

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2006 Outlook

The following summarizes our outlook for the remainder of 2006 for our power generation business and our customer risk management business.

Power Generation Business. Generally, we expect that future generation business financial results will continue to reflect sensitivity to fuel and emissions commodity prices, market prices for energy, ancillary services and capacity, transportation and transmission logistics, weather conditions and in-market asset availability. We continue to manage price risk through optimization of fuel procurement and we expect to limit long-term forward sales of power and related transactions in order to capture short-term market pricing opportunities. Any change in commodity prices will affect our earnings either positively or negatively depending on the direction of the commodity price movement.

GEN- MW. We expect our results to continue to be impacted by fuel and power prices, in-market availability of our assets and fuel availability. Although we expect power prices to continue to remain high in the Midwest, we will not be able to fully realize these prices due to volume options held by AmerenIP in our fixed price power purchase agreement with them. This agreement expires at the end of 2006. Under terms of this power purchase agreement, AmerenIP can take up to 2,800 MW of energy and ancillary services in each hour at a fixed price of $30/MWh around the clock from May-September; and, up to 2,300 MW of energy and ancillary services in each hour at a fixed price of $30/MWh around the clock during the other months. Over the course of a year, AmerenIP s takes are contractually constrained by quarterly and annual limitations. Beyond these limits, AmerenIP may request up to another 150 MW in each hour at a market-based price.

Beyond 2006, Midwest results will be affected by the expiration of this power purchase agreement and decisions we make with regard to the sale of our production in the Illinois auction described below, under potential new bilateral agreements and/or directly into the wholesale market. Depending on these decisions, expiration of this contract may result in increased exposure to market price volatility and a stronger price environment potentially allowing us to realize additional revenue.

Another factor impacting our results in the Midwest beyond 2006 will be the regulatory environment in Illinois. In January 2006, the Illinois Commerce Commission approved proposals by the two major Illinois electric utilities to hold an auction as the means by which they will procure capacity and energy necessary to serve load after 2006. While the ICC issued orders approving a reverse auction process, there remains a possibility of substantial legal, regulatory, and legislative challenge to these orders and the power of the ICC to issue them. Thus, it is difficult to predict (i) whether an auction or some other mechanism(s), if any, will be approved in advance of 2007, and (ii) what impact an auction or lack thereof will have on our results.

Operation of our Midwest generation facilities is in part dependent on our ability to procure coal. Power generators have experienced significant pressures on coal supply availability that are either transportation or supply related. Long-term supply and transportation agreements for our Midwest fleet largely mitigate these concerns from a commitment perspective; however, we have experienced decreased delivery certainty since the third quarter 2004, and more significantly since May 2005, as a result of increased track maintenance programs, weather delays and train derailments. As this situation persists in 2006, we may re-implement a program to selectively conserve coal during off-peak periods, foregoing the revenue associated with this off-peak production to ensure adequate coal supply for on-peak load during high demand periods in 2006. A similar approach was successful in fourth quarter 2005.

During 2005, our results reflected increased demand for capacity-related products from our peaking and intermediate generation facilities. In addition, we benefited from operation of all of our peaking plants at certain times during the summer months of 2005. Based on increased demand and market design changes, including the 2005 implementation of a fully-functioning market in MISO, we continue to expect a contribution from our peaking and intermediate generation facilities in the summer months of 2006. This will be largely subject to market demand and will therefore be heavily impacted by weather and system reliability.

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GEN-NE. We expect commodity fuel prices and market prices for energy and capacity to continue to be strong, although current forward prices are lower than forward market highs seen in the fall of 2005. Spreads are expected to remain volatile as fuel prices change. Warmer than normal temperatures through the first three months of 2006 have resulted in lower than expected demand. As a result, we expect year-to-year decreased runtime for our at-the-money facilities in the first half of 2006, particularly at our Roseton facility.

Our results are also dependent on our ability to maintain coal and oil deliveries to the facilities. We continue to maintain sufficient coal and oil inventories and contractual commitments to provide us with a stable fuel supply.

Additionally, our results could be affected by potential changes in New York state environmental regulations, as well as our ability to obtain permits necessary for the operation of our facilities. For further discussion of these matters, please see Note 11 Regulatory Issues Roseton State Pollutant Discharge Elimination System Permit and Note 11 Regulatory Issues Danskammer State Pollutant Discharge Elimination System Permit.

GEN-SO. We entered into various agreements in September 2005 extending the steam and energy sales component of an ongoing relationship to sell up to approximately 80 MW of energy and 1.5 million pounds per hour of steam from our CoGen Lyondell cogeneration facility to Lyondell Chemical Company for an initial term from January 2007 through December 2021 and subsequent automatic rollover terms of two years each thereafter through December 2046. Expected incremental annual operating income associated with this contract will range between $40 million to $55 million. The primary driver of this improvement is the adjustment to the price of steam supplied to Lyondell Chemical. In addition, we retain our ability to capture market upside in the Texas region for the excess generation from the Cogen Lyondell facility.

Our peaking facilities in the South continue to contribute revenue from sales of capacity mainly to local load-serving entities or wholesale buyers. We currently have a substantial portion of our portfolio capacity committed on an annual basis through 2015. Where we have uncommitted capacity and energy, we believe opportunities to sell additional capacity from these facilities will develop at times during the year. Due to the regulated, non-liquid market available in this region, our results will be impacted by our ability to complete additional sales to a limited pool of buyers for these products.

CRM. Our CRM business segment s future results of operations will be significantly impacted by our ability to complete our exit from this business. Our CRM business remains a party to certain legacy gas and power transactions, most of which have been hedged. However, we expect to continue to incur cash outflows associated with the legacy transactions. We are proactively working with our customers to exit the remainder of our obligations on economically favorable terms.

Cash Flow Disclosures

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

	Quarters Ended March 31,	
	2006	2005
	(in millions)	
Operating cash flows from our generation businesses	$ 192	$ 91
Operating cash flows from our customer risk management business	(368)	(26)
Operating cash flows from our natural gas liquids business		69
Other operating cash flows	(135)	(168)
Net cash used in operating activities	$ (311)	$ (34)

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Operating Cash Flow. Our cash flow used in operations totaled $311 million for the quarter ended March 31, 2006. During the quarter, our power generation business provided positive cash flow from operations of $192 million due to positive earnings for the period and changes in working capital primarily due to return of collateral. Our customer risk management business used approximately $368 million in cash primarily due to a $370 million termination payment on our Sterlington tolling contract, offset by other changes in working capital. Please read Note 3- Dispositions, Contract Terminations and Discontinued Operations- Dispositions and Contract Terminations Sterlington Contract Termination for further information. Other and Eliminations includes a use of approximately $135 million in cash primarily due to interest payments to service debt and general and administrative expenses, partially offset by interest income on cash balances and the receipt of approximately $20 million associated with the resolution of a legal dispute.

Our cash flow used in operations totaled $34 million for the quarter ended March 31, 2005. During the quarter, our power generation business and our natural gas liquids business provided positive cash flow from operations. Our power generation business provided cash flow from operations of $91 million due to positive earnings for the period; and our natural gas liquids business provided cash flow from operations of $69 million primarily due to positive earnings for the period. Our customer risk management business used approximately $26 million in cash primarily due to fixed payments associated with the power tolling arrangements and our final payment related to our exit from gas transportation contracts. Other and Eliminations includes a use of approximately $168 million in cash primarily due to interest payments to service debt and general and administrative expenses.

Capital Expenditures and Investing Activities. Cash provided by investing activities during the quarter ended March 31, 2006 totaled $469 million. Capital spending of $18 million was primarily comprised of $11 million, $3 million, and $3 million in the GEN-MW, GEN-NE, and GEN-SO segments, respectively. The capital spending for the GEN-MW segment primarily related to maintenance capital projects, as well as $1 million in development capital associated with the completion of the Vermilion PRB conversion. Capital spending in our GEN-NE and GEN-SO segments primarily related to maintenance and environmental projects.

The cost to acquire NRG s 50% ownership interest in Rocky Road, net of cash proceeds, totaled $40 million. Please read Note 2- Acquisition for more information. The decrease in restricted cash of $322 million related primarily to the return of our $335 million deposit associated with our former cash collateralized facility, offset by a $13 million increase in the Independence restricted cash balance.

Net cash proceeds from asset sales of $205 million was due to the sale of our 50% ownership interest in West Coast Power to NRG. Please read Note 3- Dispositions, Contract Terminations and Discontinued Operations- Dispositions and Contract Terminations West Coast Power for further information.

Cash used in investing activities during the quarter ended March 31, 2005 totaled $196 million. Capital spending of $54 million was primarily comprised of $37 million, $3 million and $10 million in the GEN-MW, GEN-NE and NGL segments, respectively. The capital spending for the GEN-MW segment primarily related to maintenance capital projects, as well as $10 million in development capital associated with the completion of the Havana PRB conversion. Capital spending in our NGL segment primarily related to maintenance capital projects and wellconnects. The cost to acquire Sithe Energies, net of cash proceeds, totaled $120 million. Proceeds from asset sales consisted of a $5 million payment to Ameren associated with the working capital adjustment related to the sale of Illinois Power.

Financing Activities. Cash used in financing activities during the quarter ended March 31, 2006 totaled $16 million, primarily due to a semi-annual dividend payment of $11 million on our Series C convertible preferred stock.

Cash used in financing activities during the quarter ended March 31, 2005 totaled $27 million. Repayments of long-term debt totaled $19 million for the three months ended March 31, 2005 and consisted of the following: (1) payments of $18 million on a maturing series of DHI senior notes and (2) payments of $1 million on DHI s term loan. Cash used in financing activities also includes a semi-annual dividend payment of $11 million on our Series C convertible preferred stock.

RISK-MANAGEMENT DISCLOSURES

The following table provides a reconciliation of the risk-management data on the unaudited condensed consolidated balance sheets:

	As of and for the Quarter Ended March 31, 2006 (in millions)
Balance Sheet Risk-Management Accounts	
Fair value of portfolio at January 1, 2006	$ (112)
Risk-management gains recognized through the income statement in the period, net	38
Cash received related to risk-management contracts settled in the period, net	(12)
Changes in fair value as a result of a change in valuation technique (1)	
Non-cash adjustments and other (2)	11
Fair value of portfolio at March 31, 2006	$ (75)

(1) Our modeling methodology has been consistently applied.
(2) This amount consists of changes in value associated with cash flow hedges on forward power sales and fair value hedges on debt.

The net risk management liability of $75 million is the aggregate of the following line items on our condensed consolidated balance sheets: Current Assets   Assets from risk-management activities, Other Assets   Assets from risk-management activities, Current Liabilities   Liabilities from risk-management activities and Other Liabilities   Liabilities from risk-management activities.

Risk-Management Asset and Liability Disclosures. The following tables depict the mark-to-market value and cash flow components of our net risk-management assets and liabilities at March 31, 2006 and December 31, 2005. As opportunities arise to monetize positions that we believe will result in an economic benefit to us, we may receive or pay cash in periods other than those depicted below:

Mark-to-Market Value of Net Risk-Management Assets (1)

	Total	2006(3)	2007	2008	2009	2010	Thereafter
	(in millions)						
March 31, 2006 (2)	$ (41)	$ 7	$ (48)	$ (7)	$ 2	$ 1	$ 4
December 31, 2005 (2)	(84)	(5)	(65)	(19)	2		3
Increase	$ 43	$ 12	$ 17	$ 12	$	$ 1	$ 1

(1) The table reflects the fair value of our risk-management asset position, which considers time value, credit, price and other reserves necessary to determine fair value. These amounts exclude the fair value associated with certain derivative instruments designated as hedges. The net risk-management liabilities at March 31, 2006 of $75 million on the unaudited condensed consolidated balance sheets include the $41 million herein as well as hedging instruments. Cash flows have been segregated between periods based on the delivery date required in the individual contracts.
(2) Our mark-to-market values at March 31, 2006 and December 31, 2005 were derived solely from market quotations.
(3) Amounts represent April 1 to December 31, 2006 values in the March 31, 2006 row and January 1 to December 31, 2005 values in the December 31, 2005 row.

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Cash Flow Components of Net Risk-Management Asset

	Three Months Ended March 31, 2006	Nine Months Ended December 31, 2006	Total 2006	2007	2008	2009	2010	Thereafter
				(in millions)				
March 31, 2006 (1)	$ 2	$ 11	$ 13	$ (46)	$ (8)	$ 2	$ 1	$ 6
December 31, 2005			1	(64)	(21)	2		4
Increase			$ 12	$ 18	$ 13	$	$ 1	$ 2

(1) The cash flow values for 2006 reflect realized cash flows for the three months ended March 31, 2006 and anticipated undiscounted cash inflows and outflows by contract based on the tenor of individual contract position for the remaining periods. These anticipated undiscounted cash flows have not been adjusted for counterparty credit or other reserves. These amounts exclude the cash flows associated with certain derivative instruments designated as hedges.

UNCERTAINTY OF FORWARD-LOOKING STATEMENTS AND INFORMATION

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

- projected operating or financial results, including anticipated cash flows from operations;
- expectations regarding capital expenditures, interest expense and other payments;
- beliefs about commodity pricing;
- strategies to capture opportunities presented by rising commodity prices and strategies to manage our risk exposure to energy price volatility while reducing our hedging;
- plans to achieve fuel-related, general and administrative, and other targeted cost savings;
- beliefs and assumptions relating to our liquidity position, including our ability to redeem the remaining outstanding 2008 Notes and to satisfy or refinance our significant debt maturities and other obligations before or as they come due;

strategies to address our substantial leverage, to access the capital markets, or to obtain additional financing or more favorable financing terms;

measures to compete effectively with industry participants;

beliefs and assumptions about market competition, fuel supply, power demand, generation capacity and regional recovery of the wholesale power generation market;

sufficiency of coal and fuel oil inventories and transportation;

beliefs about the outcome of legal and administrative proceedings, including the matters involving the western power and natural gas markets, environmental and master netting agreement matters, and the investigations primarily relating to our past trading practices;

assumptions about prospective regulatory developments;

expectations regarding environmental matters, including costs of compliance and availability and adequacy of emission credits;

strategies to remediate the material weakness existing in our accounting for income taxes:

application of the remaining proceeds from the sale of our midstream natural gas business;

positioning our power generation business for future growth and pursuing and executing acquisition or combination opportunities; and

our ability to complete our exit from the customer risk management business and the costs associated with this exit.

Any or all of our forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors, many of which are beyond our control, including those set forth under Part II Other Information, Item 1A RISK FACTORS.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 1 to the unaudited condensed consolidated financial statements for a discussion of recently issued accounting pronouncements affecting us.

CRITICAL ACCOUNTING POLICIES

Please read Critical Accounting Policies beginning on page 40 of our Form 10-K/A for a complete description of our critical accounting policies, with respect to which there have been no material changes since the filing of our Form 10-K.

Item 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk beginning on page 85 of our Form 10-K/A for a discussion of our exposure to commodity price variability and other markets risks, including foreign currency exchange rate risk. Following is a discussion of the more material of these risks and our relative exposures as of March 31, 2006.

Value at Risk (VaR). The following table sets forth the aggregate daily VaR of the mark-to-market portion of Dynegy s risk-management portfolio primarily associated with the GEN and CRM segments.

Daily and Average VaR for Risk-Management Portfolios

	March 31, 2006	December 31, 2005
	(in millions)	
One Day VaR 95% Confidence Level	$ 2	$ 5
One Day VaR 99% Confidence Level	$ 2	$ 6
Average VaR for the Year-to-Date Period 95% Confidence Level	$ 3	$ 7

Credit Risk. The following table represents our credit exposure at March 31, 2006 associated with the mark-to-market portion of our risk-management portfolio, on a net basis.

Credit Exposure Summary

	Investment Grade Quality	Non-Investment Grade Quality	Total
		(in millions)	
Type of Business:			
Financial Institutions	$ 136	$	$ 136
Commercial/Industrial/End Users	32	18	50
Utility and Power Generators	5	1	6

Total	$ 173	$ 19	$ 192

Of the $19 million in credit exposure to non-investment grade counterparties, 65% is collateralized or subject to other credit exposure protection.

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Interest Rate Risk. We are exposed to fluctuating interest rates related to variable rate financial obligations. As of March 31, 2006, our fixed rate debt instruments as a percentage of total debt instruments was approximately 87%. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of March 31, 2006, it is estimated that a one percentage point interest rate movement in the average market interest rates (either higher or lower) over the 12 months ended March 31, 2007 would either decrease or increase income before taxes by approximately $8 million. Hedging instruments that impact such interest rate exposure are included in the sensitivity analysis. Over time, we may seek to reduce the percentage of fixed rate financial obligations in our debt portfolio through the use of swaps or other financial instruments.

Derivative Contracts. The notional financial contract amounts associated with our commodity risk-management, interest rate and foreign currency exchange contracts were as follows at March 31, 2006 and December 31, 2005, respectively:

Absolute Notional Contract Amounts

	March 31, 2006	December 31, 2005
Natural Gas (Trillion Cubic Feet)	0.440	0.374
Electricity (Million Megawatt Hours) (1)	25.495	30.479
Emission Credits (Million Tons) (2)	0.031	0.043
Net Fair Value Hedge Interest Rate Swaps (In Millions of U.S. Dollars)	$ 525	$ 525
Fixed Interest Rate Received on Swaps (Percent)	4.331	4.331
Net Interest Rate Risk-Management Contract (In Millions of U.S. Dollars)	$ 25	$ 25
Fixed Interest Rate Paid (Percent)	5.998	5.998

(1) This amount includes notional volumes related to Financial Transmission Rights (FTRs) that we acquired in various ISOs during 2005.

(2) These amounts represent emission credit contracts that we are required to account for as derivatives under SFAS No. 133. These amounts do not include the emission credits that we have recorded in our inventory related to allowances that we utilize in running our power generation fleet.

Item 4 CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation included consideration of the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified by the SEC. This evaluation also considered the work completed as of the end of the first quarter 2006 relating to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002.

Based on this evaluation, our CEO and CFO concluded that, as of March 31, 2006, as a result of the material weaknesses discussed below, our disclosure controls and procedures were not effective to ensure that the information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the requisite time periods.

Notwithstanding the material weaknesses that existed at March 31, 2006, management believes, based on its knowledge, that the financial statements, and other financial information included in this report, fairly present in all material respects in accordance with GAAP our financial condition, results of operations and cash flows as of, and for, the periods presented in this report.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements would not be prevented or detected. We have identified the following material weaknesses:

Material Weakness Related to Income Taxes. As of December 31, 2005 and March 31, 2006 we did not maintain effective controls over the completeness and accuracy of the tax provision and deferred income tax balances in accordance with generally accepted accounting principles.

Specifically, our processes, procedures and controls related to the preparation, analysis and recording of the income tax provision were not effective to ensure that the deferred tax provision and deferred tax balances were recorded in accordance with generally accepted accounting principles. This control deficiency resulted in the restatement of our 2004 and 2003 annual consolidated financial statements, as well as audit adjustments to the 2005 income tax provision. This control deficiency also resulted in the restatement of the 2005 consolidated financial statements as reported in our Annual Report on Form 10-K/A. Further, this control deficiency could result in a misstatement of the income tax provision and related deferred tax accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Therefore, as of December 31, 2005 and March 31, 2006, we concluded that this control deficiency constitutes a material weakness.

Material Weakness Related to Risk Management Assets and Liabilities. As of March 31, 2006 we did not maintain effective controls over the accuracy of our risk management asset and liability balances. Our processes, procedures and controls related to the calculation and analysis of applicable pricing data were not effective to ensure that the risk management asset and liability balances were accurately reflected in the financial statements. This control deficiency resulted in an adjustment to the 2006 interim condensed consolidated financial statements prior to being reported in this Quarterly Report on Form 10-Q. Further, this control deficiency could result in a misstatement of revenue and the related risk management asset and liability balances that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Therefore, as of March 31, 2006, we concluded that this control deficiency constitutes a material weakness.

Status of Remediation of Material Weaknesses

Material Weakness Related to Income Taxes. During 2005, the following steps were taken to improve our internal controls around our tax accounting and tax reconciliation processes, procedures and controls: (i) increased levels of review in the preparation of the quarterly and annual tax provisions; (ii) formalized processes, procedures and documentation standards relating to the income tax provision; and (iii) restructured our Tax Department to ensure appropriate segregation of duties regarding preparation and review of the quarterly and annual tax provision. Despite these efforts, when making management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, we determined that those controls were still not operating effectively.

In addition to continuing the enhanced processes implemented in 2005 and described above, during 2006, we have already taken or plan to take the following steps in an attempt to remediate the material weakness reported at December 31, 2005: (i) implementing new processes around the analysis of the income tax provision, including detailed reconciliations between book basis and tax basis of significant tax sensitive balance sheet accounts; (ii) implementing additional procedures around identifying, analyzing and recording the tax effects of significant transactions; and (iii) further formalizing and documenting the procedures around the preparation and review of the tax provision and tax accounts. We have also engaged an independent consulting firm to assess and provide recommendations to strengthen our current processes and procedures. We will not be able to conclude that this material weakness has been successfully remediated, and we cannot assure you we will be able to make such conclusion, until management s testing and assessment demonstrates that such controls have operated effectively for a sufficient period of time.

We believe we are taking the steps necessary to remediate this material weakness relating to our tax accounting and tax reconciliation processes, procedures and controls. However, certain of the corrective processes, procedures and controls relate to annual controls that cannot be tested until the preparation of our 2006 annual tax provision. Accordingly, we will continue to vigorously monitor the effectiveness of these processes, procedures and controls and will make any further changes management determines are necessary.

Material Weakness Related to Risk Management Assets and Liabilities. In order to remediate this material weakness, we will implement additional controls around our risk management asset and liability valuation process, including enhanced controls and management review and approvals of price-validation process changes and system-generated controls.

Changes in Internal Controls Over Financial Reporting

Other than as noted above in this Item 4, there were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of our internal controls performed during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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DYNEGY INC.

PART II. OTHER INFORMATION

Item 1 LEGAL PROCEEDINGS

See Note 10 to the accompanying unaudited condensed consolidated financial statements for discussion of the material legal proceedings to which we are a party.

Item 1A RISK FACTORS

Item 1A. Risk Factors beginning on page 23 of our 2005 Form 10-K includes a detailed discussion of our risk factors. The information presented below updates, and should be read in conjunction with, the risk factors and information disclosed in our 2005 Form 10-K.

Risks Related to Our Business

We reported a material weakness in our internal control over financial reporting that caused a restatement and, if not remedied, it could continue to adversely affect our internal controls and financial reporting.

In connection with management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, management concluded that, as of December 31, 2005, we did not maintain effective internal control over our financial reporting due to a material weakness in our processes, procedures and controls related to the preparation, analysis and recording of the income tax provision. Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 was audited by PricewaterhouseCoopers LLP, which expressed an unqualified opinion on management s assessment and an adverse opinion on the effectiveness of our internal control over financial reporting as of December 31, 2005.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements would not be prevented or detected. We previously reported in our 2004 Form 10-K that we did not maintain effective internal control over financial reporting as of December 31, 2004 due to the same material weakness discussed above. During 2005, actions were taken to remediate the material weakness reported in our 2004 Form 10-K. Despite these efforts, when making management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, we determined that those controls were still not operating effectively.

This control deficiency resulted in the restatement of our 2004 and 2003 annual consolidated financial statements, as well as year-end audit adjustments to the 2005 income tax provision. This control deficiency also resulted in the restatement of the consolidated financial statements for the year ended December 31, 2005 as reported in our 2005 Form 10-K/A. Further, this control deficiency could have resulted in a misstatement of the income tax provision and related deferred tax accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

We have taken steps to remediate the material weakness, and plan to take additional steps during 2006. Although we believe we will address the material weakness with the remedial measures we have implemented and plan to implement, the measures we have taken to date and any future measures may not remediate the material weakness reported and we may not be able to implement and maintain effective internal control over financial reporting in the future. In addition, additional deficiencies in our internal controls may be discovered in the future. Any failure to remediate the reported material weakness or to implement new or improved controls, or difficulties encountered in their implementation, could harm our operating results, cause us to fail to meet our reporting obligations or result in material misstatements in our financial statements. Any such failure also could affect the ability of our management to certify that our internal controls are effective when it provides an assessment of our internal control over financial reporting, and could affect the results of our independent registered public accounting firm s attestation report regarding our management s assessment. Inferior internal controls and further related restatements could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our stock.

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Our growth strategy may include acquisitions or combinations that could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to realize anticipated benefits of those transactions.

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

- diversion of management s attention;
- the need to integrate acquired or combined operations;
- potential loss of key employees;
- difficulty in evaluating the power assets, operating costs, infrastructure requirements, environmental and other liabilities, and other factors beyond our control;
- potential lack of operating experience in new geographic/power markets;
- an increase in our expenses and working capital requirements; and
- the possibility that we may be required to issue a substantial amount of additional equity securities or incur additional debt to finance any such transactions.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize synergies or other anticipated benefits from a strategic transaction.

Furthermore, while we intend to pursue strategic transactions, the market for transactions is highly competitive, which may adversely affect our ability to find transactions that fit our strategic objectives. In pursuing our strategy, consistent with industry practice, we routinely engage in discussions with industry participants regarding potential transactions, large and small. We are currently engaged in discussions, although no definitive agreements have been reached. We intend to continue to engage in strategic discussions and we will need to respond to potential opportunities quickly and decisively. As a result, strategic transactions may occur at anytime and may be significant in size relative to our assets and operations.

Risks Related to Investing in Our Common Stock

We have significant debt that could negatively impact our business.

Dynegy has and will continue to have a significant amount of debt outstanding. As of May 4, 2006, we had total consolidated debt (including lease obligations) of $4.5 billion, which consisted of our senior unsecured notes and other debt, including other secured and unsecured facilities and certain operating leases of our subsidiaries. Our significant level of debt could:

- make it difficult to satisfy our financial obligations, including debt service requirements;

limit our ability to obtain additional financing to operate our business;

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- limit our financial flexibility in planning for and reacting to business and industry changes;
- impact the evaluation of our creditworthiness by counterparties to commercial agreements and affect the level of collateral we are required to post under such agreements;
- place us at a competitive disadvantage compared to less leveraged companies;
- increase our vulnerability to general adverse economic and industry conditions, including changes in interest rates and volatility in commodity prices; and
- require us to dedicate a substantial portion of our cash flows to payments on our debt, thereby reducing the availability of our cash flow for other purposes including our operations, capital expenditures and future business opportunities.

Although we recently completed a series of liability management transactions, we remain highly leveraged. Furthermore, we may incur additional indebtedness in the future. If new debt is added to our current debt levels and those of our subsidiaries, the related risks that we and they face could increase significantly.

The terms of our debt may severely limit our ability to plan for or respond to changes in our businesses.

Our secured debt obligations require us to meet specific financial tests to issue debt and make restricted payments, among other things. Further, the senior debt associated with the Sithe Independence indenture prohibits cash distributions by Independence to its affiliates, including Dynegy, unless certain project reserve accounts are funded to specified levels and the required debt service coverage ratio is met. Our ability to comply with the covenants in our financing agreements, as they currently exist or as they may be amended, may be affected by many events beyond our control, and our future operating results may not allow us to comply with the covenants, or in the event of a default, to remedy that default. Our failure to comply with those financial covenants or to comply with the other restrictions in our financing agreements could result in a default, requiring such financing agreements (and by reason of cross-default or cross-acceleration provisions, our other indebtedness) to become immediately due and payable. If we are unable to repay those amounts or to otherwise cure the default, the holders of the indebtedness under our secured debt obligations could proceed against the collateral granted to them to secure that indebtedness. If those lenders accelerate the payment of such indebtedness, we cannot assure you that we could pay or refinance that indebtedness immediately and continue to operate our business.

The ultimate outcome of unresolved legal proceedings and investigations relating to our past activities cannot be predicted. Any adverse determination could have a material adverse effect on our financial condition, results of operations and cash flows.

We are, or have in recent years been, a party to various material litigation matters and regulatory matters arising out of our business operations. These matters include, among other things, certain actions and investigations by the FERC and related regulatory bodies, litigation with respect to alleged actions in the western power and natural gas markets, a number of securities class action lawsuits that were settled in 2005, purported class action suits with respect to alleged violations of the Employment Retirement Income Security Act and various other matters. The ultimate outcome of pending matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome in each case reasonably be estimated. Three significant matters are described below:

DNE is involved in litigation or administrative proceedings regarding the State Pollutant Discharge Elimination System, or SPDES, permits for two of our facilities, Roseton and Danskammer, in New York. In April 2005, the New York State Department of Environmental Conservation, or NYSDEC, issued to DNE a draft SPDES Permit for the Roseton plant. The draft SPDES Permit contains provisions governing, among other things, the cooling water intake and the discharge of heated effluent water. In mid- 2005, three organizations filed petitions for party status seeking to impose a permit requirement that the Roseton plant install a closed cycle cooling system. We believe that Petitioners claims are without merit; however, given the high cost of installing a closed cycle cooling system, an adverse result in this proceeding could have a material adverse effect on our financial condition, results of operations and cash flows.

Danskammer s SPDES Permit was issued for a five-year term in 1987. Prior to expiration of the permit, an application to renew the SPDES Permit was filed. In November 2002, several environmental groups filed suit in the Supreme Court of the State of New York seeking, among other things, a declaratory judgment that the Danskammer SPDES Permit had expired because of alleged deficiencies in the renewal application process. In August 2004, the Court ruled that the SPDES Permit for our Danskammer facility was void, but stayed the enforcement of the decision pending further review by the Court or by the Appellate Division. In April 2006, the Appellate Division reversed the trial court and dismissed the case. The Court ruled that the environmental groups challenges to the extension of the SPDES Permit were barred by the applicable statue of limitations. If Petitioners appeal and are ultimately successful, we may be required to suspend operations at our Danskammer facility until receipt of final approval of the renewal of our Danskammer SPDES Permit. We cannot predict with any certainty the outcome of this proceeding; however, an adverse outcome, particularly a requirement that we suspend operations at our Danskammer facility for any period of time, could have a material adverse effect on our financial condition, results of operations and cash flows.

We are a party to various suits that claim damages resulting from the alleged manipulation of gas index publications and prices by us and others. In each of these suits, the plaintiffs allege that we and other energy companies engaged in an illegal scheme to inflate natural gas prices by providing false information to gas index publications. All of the complaints rely heavily on the FERC and CFTC investigations into and reports concerning index-reporting manipulation in the energy industry. We cannot predict with certainty whether we will incur any liability in connection with these lawsuits; however, given the nature of the claims and the high costs of recent settlements of similar matters, an unfavorable result in any of these pending matters could materially adversely affect our financial condition, results of operations and cash flows.

Shortly before Enron s bankruptcy filing in the fourth quarter of 2001, we determined that we had net exposure to Enron Corp. and its affiliates, including certain liquidated damages and other amounts relating to the termination of commercial transactions among the parties, of approximately $84 million. This exposure was calculated by setting off approximately $230 million owed from Dynegy entities to Enron entities against approximately $314 million owed from Enron entities to Dynegy entities. The master netting agreement between Enron and us and the valuation of the commercial transactions covered by the agreement, which valuation is based principally on the parties assessment of market prices for such period, remain subject to dispute. We previously mediated this dispute but no settlement was reached. As a result, in April 2006, Enron requested that mediation be terminated; the mediator has recommended that the case be returned to the Bankruptcy Court. In the event that Enron prevails in its position that the master netting agreement is unenforceable, our potential liability to Enron could be approximately $216 million before interest, with as much as $220 million in unsecured Dynegy claims remaining to enforce against the bankruptcy estate. If the setoff rights are modified or disallowed, either by agreement or otherwise, the amount available for our entities to set off against sums that might be due Enron entities could be reduced materially. In fact, we could be required to pay to Enron the full amount that it claims to be owed, while we would be an unsecured creditor of Enron to the extent of our claims. Given the size of the claims at issue, an adverse result could have a material adverse effect on our financial condition, results of operations and cash flows.

Item 6 EXHIBITS

The following documents are included as exhibits to this Form 10-Q:

Exhibit Number	Description
4.1	Supplemental Indenture dated August 24, 2005 between Dynegy Midstream Holdings, Inc., Dynegy Storage Technology and Services, Inc., Dynegy Gas Transportation, Inc., Dynegy Holdings Inc., the guarantors named therein, and Wilmington Trust Company, as trustee and Well Fargo Bank, N.A., as collateral trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K of Dynegy Holdings Inc. filed on March 29, 2006, File No. 000-29311).

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Exhibit Number	Description
4.2	Second Supplemental Indenture, dated as of March 28, 2006, by and among Dynegy Holdings Inc., the guarantors party thereto, Wilmington Trust Company, as trustee, and Wells Fargo Bank, N.A., as collateral trustee, supplementing the Indenture, dated as of August 11, 2003 (as supplemented by the Supplemental Indenture, dated as of August 24, 2005), pursuant to which the Second Priority Senior Secured Floating Rate Notes due 2008, 9.875% Second Priority Senior Secured Notes due 2010 and 10.125% Second Priority Senior Secured Notes due 2013 of Dynegy Holdings Inc. were issued (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on March 29, 2006, File No. 1-15659).
4.3	Second Supplemental Indenture, dated as of April 12, 2006, to that certain Indenture, originally dated as of September 26, 1996, as amended and restated as of March 23, 1998 and again as of March 14, 2001, by and between Dynegy Holdings Inc. and Wilmington Trust Company (as successor to JPMorgan Chase Bank, N.A.), as trustee, as supplemented by that certain First Supplemental Indenture, dated as of July 25, 2003 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 12, 2006, File No. 1-15659).
4.4	Registration Rights Agreement, dated as of April 12, 2006, by and among Dynegy Holdings Inc. and the several initial purchasers party thereto (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K of Dynegy Inc. filed on April 12, 2006, File No. 1-15659).
10.1	Third Amended and Restated Credit Agreement dated as of March 6, 2006 among Dynegy Holdings Inc., as Borrower, and Dynegy Inc., as Parent Guarantor (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 9, 2006, File No. 1-15659).
10.2	Agreement Concerning Employment Agreement and Stock Options dated as of March 16, 2006 between Dynegy Inc. and Bruce A. Williamson (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.3	Third Amendment to October 18, 2002 Employment Agreement dated as of March 16, 2006 between Dynegy Inc. and Bruce A. Williamson (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.4	Non-Qualified Stock Option Award Agreement dated as of March 16, 2006, between Dynegy Inc., all of its subsidiaries and Bruce A. Williamson (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.5	Form of Performance Award Agreement (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.6	Amendment to the Dynegy Inc. 2000 Long Term Incentive Plan effective January 1, 2006 (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.7	Amendment to the Dynegy Inc. 2002 Long Term Incentive Plan effective January 1, 2006 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.8	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
10.9	Form of Restricted Stock Award Agreement (Managing Directors and Above) (incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).

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Exhibit Number	Description
10.10	Form of Restricted Stock Award Agreement (Directors and Below) (incorporated by reference to Exhibit 10.9 to the Current Report on Form 8-K of Dynegy Inc. filed on March 17, 2006, File No. 1-15659).
**10.11	Purchase Agreement dated as of March 29, 2006 for the sale of $750,000,000 aggregate principal amount of the 8.375% Senior Unsecured Notes due 2016 of Dynegy Holdings, Inc. among Dynegy Holdings Inc. and the several initial purchasers named therein.
**10.12	Second Lien Shared Security Agreement Supplement dated as of August 24, 2005 by Dynegy Midstream Holdings, Inc., Dynegy Storage Technology and Services, Inc. and Dynegy Gas Transportation, Inc. in favor of Wells Fargo Bank, N.A., as collateral trustee (supplementing the Second Lien Shared Security Agreement dated August 11, 2003 among Dynegy Holdings Inc., Dynegy Inc., as a grantor, the other grantors named therein and Wells Fargo Bank Minnesota, N.A., as collateral trustee)
10.13	Fourth Amended and Restated Credit Agreement dated as of April 19, 2006 among Dynegy Holdings Inc., as borrower, Dynegy Inc., as parent guarantor, the other guarantors party thereto, the lenders party thereto and various other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on April 20, 2006, File No. 1-15659).
**31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Chief Executive Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

** Filed herewith

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

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DYNEGY INC.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		DYNEGY INC.
Date: May 10, 2006	By:	/s/ HOLLI C. NICHOLS **Holli C. Nichols**
		Executive Vice President and Chief Financial Officer
		(Duly Authorized Officer and Principal Financial Officer)

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