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 June 30, 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, 400,782,848 shares outstanding as of August 4, 2006; Class B common stock, no par value per share, 96,891,014 shares outstanding as of August 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, our and the Company refer to Dynegy Inc. and its subsidiaries, unless the context clearly indicates otherwise.

APB	Accounting Principles Board
ARO	Asset retirement obligation
Cal ISO	The California Independent System Operator
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.
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
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
ICC	Illinois Commerce Commission
ISO	Independent System Operator
LNG	Liquefied natural gas
MISO	Midwest Independent Transmission Operator, Inc.
MMBtu	Millions of British thermal units
MW	Megawatts
MWh	Megawatt hour
NGL	Our natural gas liquids business segment

NNG	Northern Natural Gas Company
NO_x	Nitrogen Oxide
NRG	NRG Energy, Inc.
NYSDEC	New York State Department of Environmental Conservation
PRB	Powder River Basin coal
PUHCA	Public Utility Holding Company Act of 1935, as amended
SAB	SEC Staff Accounting Bulletin
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
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)

	June 30, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 358	$ 1,549
Restricted cash	239	397
Accounts receivable, net of allowance for doubtful accounts of $95 and $103, respectively	342	611
Accounts receivable, affiliates	1	29
Inventory	216	214
Assets from risk-management activities	358	665
Deferred income taxes	15	14
Prepayments and other current assets	141	227
Assets held for sale (Note 3)	1	
Total Current Assets	1,671	3,706
Property, Plant and Equipment	6,402	6,515
Accumulated depreciation	(1,264)	(1,192)
Property, Plant and Equipment, Net	5,138	5,323
Other Assets		
Unconsolidated investments	4	270
Restricted investments	83	85
Assets from risk-management activities	66	165
Intangible assets	376	392
Deferred income taxes	3	3
Other long-term assets	154	182
Assets held for sale (Note 3)	194	
Total Assets	$ 7,689	$ 10,126
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 246	$ 504
Accounts payable, affiliates		46
Accrued interest	59	159
Accrued liabilities and other current liabilities	194	649
Liabilities from risk-management activities	399	687
Notes payable and current portion of long-term debt	70	71
Total Current Liabilities	968	2,116
Long-term debt	3,191	4,028
Long-term debt, affiliates	200	200
Long-Term Debt	3,391	4,228

Other Liabilities		
Liabilities from risk-management activities	124	255
Deferred income taxes	440	558
Other long-term liabilities	425	429
Total Liabilities	5,348	7,586
Commitments and Contingencies (Note 10)		
Redeemable Preferred Securities, redemption value of $400 at December 31, 2005		400
Stockholders Equity		
Class A Common Stock, no par value, 900,000,000 shares authorized at June 30, 2006 and December 31, 2005; 402,470,641 and 305,129,052 shares issued and outstanding at June 30, 2006 and December 31, 2005, respectively	3,364	2,949
Class B Common Stock, no par value, 360,000,000 shares authorized at June 30, 2006 and December 31, 2005; 96,891,014 shares issued and outstanding at June 30, 2006 and December 31, 2005	1,006	1,006
Additional paid-in capital	36	51
Subscriptions receivable	(8)	(8)
Accumulated other comprehensive income, net of tax	20	4
Accumulated deficit	(2,008)	(1,793)
Treasury stock, at cost, 1,786,224 shares at June 30, 2006 and 1,714,026 shares at December 31, 2005	(69)	(69)
Total Stockholders Equity	2,341	2,140
Total Liabilities and Stockholders Equity	$ 7,689	$ 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 June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Revenues	$ 439	$ 459	$ 1,039	$ 921
Cost of sales, exclusive of depreciation shown separately below	(307)	(380)	(716)	(910)
Depreciation and amortization expense	(57)	(54)	(117)	(109)
Impairment and other charges	(9)	(7)	(11)	(6)
Gain on sale of assets, net	3		3	
General and administrative expenses	(50)	(82)	(101)	(345)
Operating income (loss)	19	(64)	97	(449)
Earnings from unconsolidated investments		4	2	7
Interest expense	(107)	(96)	(205)	(185)
Debt conversion costs	(247)		(247)	
Other income and expense, net	10	6	30	9
Loss from continuing operations before income taxes	(325)	(150)	(323)	(618)
Income tax benefit (Note 13)	118	41	115	215
Loss from continuing operations	(207)	(109)	(208)	(403)
Income from discontinued operations, net of tax benefit of $2, $98, $1 and $80, respectively (Notes 3 and 13)		134	1	166
Income (loss) before cumulative effect of change in accounting principle	(207)	25	(207)	(237)
Cumulative effect of change in accounting principle, net of tax expense of zero			1	
Net income (loss)	(207)	25	(206)	(237)
Less: preferred stock dividends	4	6	9	11
Net income (loss) applicable to common stockholders	$ (211)	$ 19	$ (215)	$ (248)
Earnings (Loss) Per Share (Note 9):				
Basic earnings (loss) per share:				
Loss from continuing operations	$ (0.48)	$ (0.30)	$ (0.51)	$ (1.09)
Income from discontinued operations		0.35		0.44
Cumulative effect of change in accounting principle				
Basic earnings (loss) per share	$ (0.48)	$ 0.05	$ (0.51)	$ (0.65)
Diluted earnings (loss) per share:				
Loss from continuing operations	$ (0.48)	$ (0.30)	$ (0.51)	$ (1.09)
Income from discontinued operations		0.35		0.44
Cumulative effect of change in accounting principle				
Diluted earnings (loss) per share	$ (0.48)	$ 0.05	$ (0.51)	$ (0.65)
Basic shares outstanding	442	380	421	379

Diluted shares outstanding	513	506	519	505

See the notes to condensed consolidated financial statements.

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DYNEGY INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (in millions)

	Six Months Ended June 30,	
	2006	**2005**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (206)	$ (237)
Adjustments to reconcile net loss to net cash flows from operating activities:		
Depreciation and amortization	148	151
Impairment and other charges	11	(1)
Earnings from unconsolidated investments, net of cash distributions	(2)	47
Risk-management activities	(52)	(1)
Gain on sale of assets, net	(4)	
Deferred income taxes	(119)	(293)
Cumulative effect of change in accounting principle, net of tax (Note 1)	(1)	
Legal and settlement charges	23	86
Independence toll settlement costs		170
Debt conversion charges	247	
Other	32	2
Changes in working capital:		
Accounts receivable	294	(24)
Inventory	4	(9)
Prepayments and other assets	79	180
Accounts payable and accrued liabilities	(819)	(107)
Changes in non-current assets	(6)	(4)
Changes in non-current liabilities	3	31
Net cash used in operating activities	(368)	(9)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(59)	(93)
Proceeds from asset sales, net	6	(5)
Business acquisitions, net of cash acquired		(120)
Net proceeds from exchange of unconsolidated investments, net of cash acquired (Note 2 and Note 3)	165	
Decrease in restricted cash and restricted investments	162	8
Other investing	(3)	
Net cash provided by (used in) investing activities	271	(210)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings, net	1,071	
Repayments of long-term borrowings	(1,683)	(38)
Debt conversion costs	(247)	
Redemption of Series C Preferred	(400)	
Proceeds from issuance of capital stock	182	2
Dividends and other distributions, net	(17)	(11)
Other financing, net		(4)
Net cash used in financing activities	(1,094)	(51)

Net decrease in cash and cash equivalents	(1,191)	(270)
Cash and cash equivalents, beginning of period	1,549	628
Less: Cash classified as held for sale at end of period (Note 3)		(16)
Cash and cash equivalents, end of period	$ 358	$ 342
Other non-cash financing activity:		
Conversion of Convertible Subordinated Debentures due 2023 (Note 7)	$ 225	$

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 June 30, 2006	Three Months Ended June 30, 2005
Net income (loss)	$ (207)	$ 25
Cash flow hedging activities, net:		
Unrealized mark-to-market gains (losses) arising during period, net	12	(3)
Reclassification of mark-to-market gains to earnings, net	(3)	(1)
Changes in cash flow hedging activities, net (net of tax benefit (expense) of ($5) and $3, respectively)	9	(4)
Foreign currency translation adjustments	3	
Other comprehensive income (loss), net of tax	12	(4)
Comprehensive income (loss)	$ (195)	$ 21

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Net loss	$ (206)	$ (237)
Cash flow hedging activities, net:		
Unrealized mark-to-market gains (losses) arising during period, net	25	(21)
Reclassification of mark-to-market (gains) losses to earnings, net	(12)	11
Changes in cash flow hedging activities, net (net of tax benefit (expense) of ($8) and $7, respectively)	13	(10)
Foreign currency translation adjustments	3	
Other comprehensive income (loss), net of tax	16	(10)
Comprehensive loss	$ (190)	$ (247)

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 June 30, 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 May 1, 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 of a normal and recurring nature 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 and six months ended June 30, 2006, we recorded additional AROs of $5 million, no material AROs were settled, and revisions to estimated cash flows were not material. During the three and six months ended June 30, 2006, our accretion expenses were approximately $2 million and $3 million, respectively. During the three and six months ended June 30, 2005, there were no material additional AROs recorded or settled, and our accretion expenses and revisions to estimated cash flows were not material. At June 30, 2006, our ARO liabilities were $50 million for our GEN-MW segment and $14 million for our GEN-NE segment.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended June 30, 2006 and 2005

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 recorded in the first quarter 2006, 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 and six months ended June 30, 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(R), our net loss and basic and diluted loss per share amounts would not have been impacted for the three and six months ended June 30, 2006 and 2005.

Please read Note 12 Employee Compensation, Savings and Pension Plans for further discussion of our share-based compensation.

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

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended June 30, 2006 and 2005

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.

Accounting Principles Not Yet Adopted

FIN No. 48. On July 12, 2006, the FASB issued FIN No. 48, Accounting for Uncertainty in Income Taxes. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of an income tax position taken or expected to be taken in an income tax return. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. We are currently evaluating the impact of this statement on our financial statements.

Note 2 Acquisition

Rocky Road. On March 31, 2006, contemporaneous with our sale of our interest in West Coast Power (Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations West Coast Power), 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%), for net proceeds of $165 million, net of cash acquired. As a result of the transaction, we became the primary beneficiary of the entity as provided under the guidance in FIN No. 46(R), and thus consolidated the assets and liabilities of the entity at March 31, 2006. Please read Note 6 Unconsolidated Investments Variable Interest Entities for further discussion.

Note 3 Dispositions, Contract Terminations and Discontinued Operations

Dispositions and Contract Terminations

Rockingham. On May 21, 2006, we entered into an agreement with Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC (a subsidiary of Duke Energy) for the sale of our Rockingham facility, a peaking facility in North Carolina, which is in GEN-SO, for $195 million in cash. The transaction is expected to close in the fourth quarter 2006, subject to obtaining certain regulatory approvals and satisfaction of customary closing conditions. The proceeds from the sale would be used to repay our borrowings under the $150 million Term Loan. Please read Note 7 Debt Senior Secured Credit Facility for further discussion of the Term Loan.

During the second quarter 2006, Rockingham met the held for sale classification requirements of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , and is classified as such on our unaudited condensed consolidated balance sheet. The major classes of current and long-term assets classified as assets held for sale at June 30, 2006 are $194 million of Property, Plant and Equipment, Net and $1 million of Inventory.

SFAS No. 144 also requires that long-lived assets not be depreciated or amortized while they are classified as held for sale. As such, we discontinued depreciation and amortization of Rockingham s property, plant and equipment during the second quarter 2006. Depreciation and amortization expense related to Rockingham totaled $1 million and $2 million in the three- and six-month periods ended June 30, 2006, compared to $2 million and $3 million in the three- and six-month periods ended June 30, 2005. In addition, SFAS No. 144 requires a loss to be

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended June 30, 2006 and 2005

recognized if assets held for sale less liabilities held for sale are in excess of fair value less costs to sell. Accordingly, we recorded a pre-tax impairment of $9 million in the three months ended June 30, 2006, which is included in Impairment and other charges on our unaudited condensed consolidated statements of operations.

West Coast Power. On March 31, 2006, contemporaneous with our purchase of Rocky Road (please read Note 2 Acquisition Rocky Road), 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 in southern California totaling approximately 1,800 megawatts, for net proceeds of approximately $165 million, net of cash acquired. 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. 46(R). Please read 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 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

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 June 30, 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 $14 million for the three months ended June 30, 2006 and 2005, respectively, and zero and $25 million for the six months ended June 30, 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

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended June 30, 2006 and 2005

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 DGC (our communications business) and our U.K. CRM business, which have been accounted for as discontinued operations under SFAS No. 144.

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 June 30, 2006				
Income from operations before taxes	$ (2)	$	$	$ (2)
Income from operations after taxes	1		(1)	
Three Months Ended June 30, 2005				
Revenues	$	$	$ 933	$ 933
Income from operations before taxes	1		35	36
Income from operations after taxes	(1)	3	132	134

	U.K. CRM	DGC	NGL	Total
		(in millions)		
Six Months Ended June 30, 2006				
Income from operations before taxes	$ (1)	$	$ 1	$
Income from operations after taxes	1			1
Six Months Ended June 30, 2005				
Revenues	$	$	$ 1,979	$ 1,979
Income from operations before taxes	5		81	86
Income from operations after taxes	3	2	161	166

In the six months ended June 30, 2005, we recognized $5 million of pre-tax income primarily associated with U.K. CRM s receipt of 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 implemented a restructuring plan (the 2005 Restructuring Plan). The 2005 Restructuring Plan resulted in a reduction of approximately 40 positions and was complete by June 30, 2006. We recognized a pre-tax charge, primarily in our Other segment, of $11 million in the fourth quarter 2005. We recognized approximately zero and $2 million of charges in the three and six months ended June 30, 2006, respectively, when transitional services were completed by certain affected employees. These charges related entirely to severance costs.

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended June 30, 2006 and 2005

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		(11)
Balance at June 30, 2006	$	

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 Fees and Operating Leases (in millions)	Total
Balance at December 31, 2005	$ 3	$ 16	$ 19
Cash payments		(4)	(4)
Balance at June 30, 2006	$ 3	$ 12	$ 15

Including the $2 million accrual for operating leases made in connection with the sale of DMSLP (for further information please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids) we have an aggregate accrual of $14 million as of June 30, 2006, associated with operating leases. We expect this amount 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 commodity prices we consider favorable under the circumstances. Interest rate swaps have been used to convert floating interest-rate obligations to fixed-rate obligations.

During the three and six months ended June 30, 2006, we recorded $4 million of income 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 and six months ended June 30, 2005, we recorded a $2 million and $6 million charge, respectively, 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 and six months ended June 30, 2006 and 2005, no amounts were reclassified to earnings in connection with forecasted transactions that were no longer considered probable of occurring.

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The balance in cash flow hedging activities, net at June 30, 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 gains of approximately $5 million are currently estimated to be reclassified into earnings over the 12-month period ending June 30, 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 and six months ended June 30, 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 and six months ended June 30, 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 June 30, 2006, we had no net investment hedges in place.

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:

	June 30, 2006	December 31, 2005
	(in millions)	
Cash flow hedging activities, net	$ 11	$ (2)
Foreign currency translation adjustment	27	24
Minimum pension liability	(18)	(18)
Accumulated other comprehensive income, net of tax	$ 20	$ 4

Note 6 Unconsolidated Investments

A summary of our unconsolidated investments is as follows:

	June 30, 2006	December 31, 2005
	(in millions)	
Equity affiliates:		
GEN MW	$	$ 60
GEN SO	4	210
Total unconsolidated investments	$ 4	$ 270

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

	Three Months Ended June 30,			
	2006		2005	
	Total	Equity Share	Total	Equity Share
	(in millions)			
Revenues	$ 26	$ 13	$ 172	$ 70
Operating income	2	1	15	7
Net income	1		15	7

	Six Months Ended June 30,			
	2006		2005	
	Total	Equity Share	Total	Equity Share
	(in millions)			
Revenues	$ 60	$ 30	$ 348	$ 142
Operating income	10	5	28	11
Net income	7	3	29	11

Earnings from unconsolidated investments for the three months ended June 30, 2006, were less than $1 million. Earnings from unconsolidated investments of $7 million for the three months ended June 30, 2005, includes $3 million of earnings from NGL investments which are included in income from discontinued operations on our unaudited condensed consolidated statements of operations.

Earnings from unconsolidated investments of $3 million for the six months ended June 30, 2006, were offset by a $1 million impairment of our investment in Panama. Earnings from unconsolidated investments of $11 million for the six months ended June 30, 2005, includes $4 million of earnings from NGL investments which are included in income from discontinued operations on our unaudited condensed consolidated statements of operations.

On May 15, 2006, we sold our interests in our power generating facility located in Panama. Net proceeds associated with the sale were approximately $3 million, and we did not recognize a gain or loss on the sale.

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 read 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.

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

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Coast Power, resulting in the receipt of net cash proceeds of approximately $160 million from NRG. 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 $29 million intangible asset related to a contract to provide capacity and energy, and $50 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 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 VIEs. 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 June 30, 2006, the equipment leases have remaining terms from one to fifteen years and involve a maximum aggregate obligation of $120 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) a percentage of 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. If the decreased pricing does not reduce the tracking account to zero, a lump sum payment for the remainder of the balance will be due. 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 June 30, 2006, was approximately $313 million, and the obligations with respect to each Tracking Account are secured by the assets of the respective facility. 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. On July 31, we received notice from the prospective purchaser terminating the Purchase and Sale Agreement, as provided in the agreement.

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Note 7 Debt

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

	June 30, 2006	December 31, 2005
	(in millions)	
Dynegy Holdings Inc.		
Term Loan, floating rate due 2012	$ 150	$
Term Facility, floating rate due 2012	200	
Senior Notes, 7.45% due 2006	22	22
Senior Notes, 6.875% due 2011	489	499
Senior Notes, 8.75% due 2012	481	491
Senior Unsecured Notes, 8.375% due 2016	750	
Senior Debentures, 7.125% due 2018	174	175
Senior Debentures, 7.625% due 2026	173	174
Second Priority Senior Secured Notes, floating rate due 2008	74	225
Second Priority Senior Secured Notes, 9.875% due 2010	11	625
Second Priority Senior Secured Notes, 10.125% due 2013		900
Subordinated Debentures payable to affiliates, 8.316%, due 2027	200	200
Sithe Energies		
Subordinated Debt, 7.0% due 2034	419	419
Senior Notes, 8.5% due 2007	39	57
Senior Notes, 9.0% due 2013	409	409
Dynegy Inc.		
Convertible Subordinated Debentures, 4.75% due 2023		225
	3,591	4,421
Unamortized discount on debt, net	(130)	(122)
	3,461	4,299
Less: Amounts due within one year, including non-cash amortization of basis adjustments	70	71
Total Long-Term Debt	$ 3,391	$ 4,228

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Aggregate debt maturities for the remainder of 2006, the next four years and thereafter of the principal amounts of all long-term indebtedness as of June 30, 2006 are as follows:

	Total	2006	2007	2008	2009	2010	Thereafter
				(in millions)			
Dynegy Holdings Inc.	$ 2,724	$ 26	$	$ 74	$	$ 11	$ 2,613
Sithe Energies	737	24	40	44	57	62	510
Total	$ 3,461	$ 50	$ 40	$ 118	$ 57	$ 73	$ 3,123

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, JPMorgan 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 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 were 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 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.

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On May 26, 2006, we closed a $150 million term loan (the Term Loan), of which $50 million was used to make a one-time cash dividend from DHI to Dynegy (the DHI Dividend) and the remainder used for working capital and general corporate purposes (please read Note 8 Related Party Transaction Series C Convertible Preferred Stock). The Term Loan, which will be repaid with proceeds from the sale of Rockingham, was structured as a new tranche under the Fourth Senior Secured Credit Facility. The Term Loan will mature on the earlier of five business days after the consummation of the pending sale of the Rockingham facility or January 31, 2012. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Rockingham for further discussion of the sale.

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 $151 million of our $225 million Second Priority Senior Secured Floating Rate Notes due 2008 (the 2008 Notes), $614 million 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 to eliminate or modify substantially all of the restrictive covenants, certain events of default and related provisions and release certain liens securing the obligations of DHI and the guarantors of the Second Priority Notes.

Total cash paid to repurchase the $1,664 million of Second Priority Notes, including consent fees and accrued interest, was $1,904 million. We recorded a charge of approximately $228 million in the second quarter 2006 associated with this transaction, of which $202 million is included in debt conversion costs and $26 million of acceleration of amortization of financing costs and write-offs of discounts and premiums is included in interest expense on our unaudited condensed consolidated statements of operations.

On July 15, 2006, we redeemed the remaining $74 million of our 2008 Notes, at a redemption price of 103% of the principal amount, plus accrued and unpaid interest to the redemption date. The interest rate on the 2008 Notes was based on three-month LIBOR plus 650 basis points. The remaining outstanding 2010 Notes are redeemable at our option on or after July 15, 2007 in accordance with the terms of the indenture governing the Second Priority Notes.

Senior Unsecured Notes. On April 12, 2006, DHI issued $750 million 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. In connection with the Senior Notes Offering, DHI entered into a registration rights agreement with the initial purchasers of the New Senior Notes pursuant to which DHI has agreed to offer to exchange the New Senior Notes for a new issue of substantially identical notes registered under the Securities Act of 1933. In the event DHI breaches its obligations under the registration rights agreement, DHI will be obligated to pay additional interest to holders of the New Senior Notes.

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Convertible Subordinated Debentures due 2023. On May 15, 2006, we converted all $225 million of our outstanding 4.75% Convertible Subordinated Debentures due 2023 into shares of our Class A common stock (the Convertible Debenture Exchange). In this transaction, we issued an aggregate of 54,598,369 shares of our Class A common stock and paid the debenture holders an aggregate of approximately $47 million in premiums and accrued and unpaid interest using cash on hand. We recorded a charge of approximately $44 million in the second quarter 2006 associated with this transaction, which is included in debt conversion costs on our unaudited condensed consolidated statements of operations.

Sithe Subordinated Debt Exchange. On July 21, 2006, DHI executed and consummated an exchange agreement (the Exchange Agreement), by and among DHI and RCP Debt, LLC and RCMF Debt, LLC (together, the Reservoir Entities). Pursuant to the Exchange Agreement, the Reservoir Entities exchanged approximately $419 million principal amount of the subordinated debt of Independence, together with all claims for accrued and unpaid interest thereon and all other rights and all obligations of the Reservoir Entities under the agreement pursuant to which the subordinated debt was issued (together, the Sithe Debt), for approximately $297 million principal amount of DHI s 8.375% Senior Unsecured Notes due 2016 (the Additional Notes). The Additional Notes have terms and conditions identical to, and are fungible for trading and other purposes with, the $750 million aggregate principal amount of the New Senior Notes issued on April 12, 2006. In connection with the Exchange Agreement, DHI entered into a registration rights agreement with the Reservoir Entities pursuant to which DHI has agreed to offer to exchange the Additional Notes for a new issue of substantially identical notes registered under the Securities Act of 1933. In the event DHI breaches its obligations under the registration rights agreement, DHI will be obligated to pay additional interest to the holders of the Additional Notes. The registration rights agreement provides the Reservoir Entities with other rights and benefits, and imposes on DHI other obligations, substantially similar to those set forth in the registration rights agreement described above and entered into with the purchasers of the New Senior Notes. We will record a charge of approximately $35 million in the third quarter of 2006 associated with this transaction.

Note 8 Related Party Transaction

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 CUSA 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% of the liquidation value per annum. We made a semi-annual dividend payment of $11 million in February 2006. On May 26, 2006, we redeemed all of the outstanding shares of our Series C Preferred, which were held by CUSA. In order to redeem the Series C Preferred, we paid CUSA $400 million in cash, plus accrued and unpaid dividends totaling approximately $6.3 million. We used approximately $178 million in net proceeds from an equity offering of 40.25 million shares of our Class A common stock that closed on the same day (including net proceeds of $23 million from the underwriters exercise of their option to purchase an additional 5.25 million shares), with the balance funded from cash on hand and the DHI Dividend. The redemption of the Series C Preferred eliminated the associated $22 million annual preferred dividend and reduced the number of diluted shares of our common stock outstanding.

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

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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.

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 June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in millions, except per share amounts)			
Loss from continuing operations	$ (207)	$ (109)	$ (208)	$ (403)
Preferred stock dividends	(4)	(6)	(9)	(11)
Loss from continuing operations for basic loss per share	(211)	(115)	(217)	(414)
Effect of dilutive securities:				
Interest on convertible subordinated debentures	1	2	3	3
Dividends on Series C Preferred	4	6	9	11
Loss from continuing operations for diluted loss per share	$ (206)	$ (107)	$ (205)	$ (400)
Basic weighted-average shares	442	380	421	379
Effect of dilutive securities:				
Stock options	1	2	1	2
Convertible subordinated debentures	28	55	41	55
Series C Preferred	42	69	56	69
Diluted weighted-average shares	513	506	519	505
Loss per share from continuing operations:				
Basic	$ (0.48)	$ (0.30)	$ (0.51)	$ (1.09)
Diluted (1)	$ (0.48)	$ (0.30)	$ (0.51)	$ (1.09)

(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 and six months ended June 30, 2006 and 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 read Note 2 Accounting Policies Contingencies, Commitments, Guarantees and

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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.

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.

Summary of Recent Developments. As described in greater detail below, the following significant developments involving our material legal proceedings occurred in the second quarter:

In June 2006, we reached a tentative agreement to settle state class action claims by California purchasers alleging price manipulation and false reporting of natural gas trades filed against us (including Dynegy and West Coast Power). We agreed to pay $30 million to settle these claims; however, the settlement does not include similar cases filed by individual plaintiffs, which we continue to vigorously defend. In August 2006, we tentatively agreed to settle class action claims by California natural gas re-sellers and co-generators (to the extent they purchased natural gas to generate electricity for re-sale) pending in Nevada federal court for $2.4 million. For further information please read Gas Index Pricing Litigation below.

The above summary of recent developments is qualified in its entirety by, and should be read in conjunction with, the more detailed summary of our significant legal proceedings set forth below.

Enron Trade Credit Litigation. Shortly before Enron Corp. and its affiliates (collectively, Enron) filed bankruptcy petitions in the fourth quarter of 2001, we determined that we had net exposure to Enron relating to the termination of commercial transactions among the parties, including certain liquidated damages and other amounts, in accordance with a master netting agreement that allowed certain amounts owed from Dynegy entities to Enron entities to be set off against other amounts 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, in which case Dynegy would have approximately $270 million in unsecured claims to pursue against the bankruptcy estates of several Enron affiliates, as well as unsecured guaranty claims to pursue against the bankruptcy estate of Enron Corp. Although the parties have engaged in settlement discussions, including through mediation, no such agreement has been reached. Motions for partial summary judgment have been filed by both parties and are expected to be considered by the Court in the fourth quarter of 2006.

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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 were named defendants in numerous lawsuits in state and federal court claiming damages resulting from alleged price manipulation and false reporting of natural gas prices. The cases are pending in California, Nevada, Alabama and Tennessee. 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. Except as specifically mentioned below, the cases are actively engaged in discovery.

During the last year, cases pending in Nevada federal court were dismissed on defendants motions. Certain plaintiffs have appealed to the Ninth Circuit, which coordinated the cases before the same appellate panel. A decision from the Ninth Circuit is not expected until 2007.

Pursuant to various motions, the cases pending in California state court have been coordinated 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 June 2006, we tentatively agreed to settle class action claims in the Coordinated Gas Index Cases for $30 million. The settlement does not include similar claims filed by individual plaintiffs in the Coordinated Gas Index Cases, which we continue to vigorously defend. In August 2006, we tentatively agreed to settle class action claims by California natural gas re-sellers and co-generators (to the extent they purchased natural gas to generate electricity for re-sale) pending in Nevada federal court for $2.4 million. Both settlements are subject to fairness hearings and final Court approvals, which we expect to occur in the fourth quarter of 2006. The settlements are without admission of wrongdoing, and Dynegy and West Coast Power continue to deny class plaintiffs allegations.

In February 2006, we reached a settlement in *In re Natural Gas Commodity Litigation*, pending in New York federal court. 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 we 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. In May 2006, the Court approved the settlement and entered an order dismissing the case.

We are analyzing the remaining 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. We have recorded reserves that we consider reasonable in connection with these matters.

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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.

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 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.

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

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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.

Finally, there is a pending appeal in the Ninth Circuit Court of Appeals challenging a FERC Order affirming the validity of the former West Coast Power CDWR long term contract. We are currently awaiting a ruling on this appeal and cannot predict its outcome.

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.

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. The Agreement further provides that NRG will manage the CDWR appeal described above and indemnify Dynegy for any resulting losses, subject to certain conditions. 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, alleged 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 and employees as defendants and amending the fraud claims. In June 2006, the court granted our motion to dismiss plaintiffs fraud claims for failing to plead those claims with particularity. The remaining counts in the March 2006 amended complaint remain pending.

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 through 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 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 alleged plan participants that is materially identical to the original action. In March 2006, the original action was dismissed by the court with prejudice based on lack of standing and lack of subject matter jurisdiction, and the plaintiffs in that matter have appealed that dismissal. The second putative class action relating to the DMG Salaried Plan remains pending at the class discovery stage.

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We believe that we have meritorious defenses to plaintiffs claims in 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 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 which was denied by the trial court in December 2005. Plaintiffs appealed the decision to the New York Appellate Division, which affirmed the trial court s ruling in August 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 October 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 as a defendant 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

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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 vigorously defend against them. 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.

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. Following a five-week trial, in August 2006 the jury returned a verdict finding the former employee guilty on seven counts of wire fraud and not guilty on two counts of wire fraud and three counts of false reporting. The jury was unable to reach a verdict on the remaining counts, including one count of conspiracy and ten counts of false reporting.

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 litigation relating to those plans described above.

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Calpine Corporation Bankruptcy. Calpine Corporation filed for Chapter 11 Bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York (the Bankruptcy Court) on December 20, 2005. The filing included Nissequogue Cogen Partners (NCP), a subsidiary of Calpine. NCP purchased gas from DMT under a long term gas sales agreement. At the time of the bankruptcy filing, NCP owed DMT approximately $8 million for pre-petition natural gas deliveries. NCP and DMT reached a settlement pursuant to the Federal Rules of Bankruptcy Procedure in which the parties agreed to the mutual termination of the long term gas sales agreement effective May 1, 2006, and settlement of all claims between NCP and DMT, including full payment for the pre-petition and post-petition gas deliveries. DMT received a settlement payment of approximately $8 million from NCP on June 9, 2006.

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.

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 if an adjudicatory hearing on the Draft SPDES Permit occurs, it will be held in the fourth quarter 2006. We believe that the Petitioners claims are without merit, and we plan to vigorously oppose 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.

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 filed a timely and sufficient application to renew the SPDES Permit. 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.

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In January 2005 the NYSDEC issued a Draft SPDES Permit renewal and an adjudicatory hearing was scheduled for the fall of 2005. The Petitioners, Riverkeeper, Inc., Natural Resource Defense Council, Inc. and Scenic Hudson, Inc., sought 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 Deputy Commissioner s decision directing that the NYSDEC staff issue the revised Draft SPDES Permit was issued on May 24, 2006. On June 1, 2006, the NYSDEC issued the revised SPDES Permit with conditions generally favorable to us. The revised 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. On July 24, 2006, Riverkeeper and Scenic Hudson filed suit in the Supreme Court of the State of New York, Westchester County seeking to vacate the Deputy Commissioner s decision and the revised Danskammer SPDES Permit. We believe that the decision of the Deputy Commissioner is well reasoned and will be affirmed. However, in the event the decision is not affirmed and we ultimately are required to install a closed cycle cooling system, this could have a material adverse effect on our financial condition, results of operations and cash flows.

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 responsible for any loss suffered by the parties as a result of such litigation. Please read California Market Litigation and Gas Index Pricing Litigation above for further discussion.

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

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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 June 30, 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 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 condensed consolidated statements of operations. In late June 2006, the Administrative Law Judge in one of the ongoing cases issued a Proposed Order adopting the disallowances recommended by the ICC Staff in that case. This Proposed Order is subject to further proceedings before the ICC before it issues a final Order, which we anticipate to occur in the fall of 2006. 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 considers the probability of an adverse outcome remote.

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 less than $1 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 NNG, 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.

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Black Mountain Guarantee. Through one of our subsidiaries, we hold a 50% ownership interest in Black Mountain (Nevada Cogeneration) (Black Mountain), in which our partner is a Chevron subsidiary. Black Mountain 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 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 June 30, 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 $56 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, 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, Qualified Facilities, 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 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. 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. Numerous parties have appealed various aspects of the ICC Orders approving the auctions to the state intermediate appellate courts. More recently, the Illinois Attorney General has also filed for direct review by the state Supreme Court and a stay of the ICC Orders pending that review, which was denied. There have also been requests to the ICC to delay the auctions until later this fall or even next year. Thus far, neither the courts nor the ICC has taken action to delay the auctions, although such actions could still occur. Separately, Commonwealth Edison and Ameren have filed at the ICC differing plans to mitigate the anticipated rate

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increases for residential customers. Because at least some aspects of some of these mitigation plans require legislative action, there is the possibility that the Illinois General Assembly will consider legislation either in its veto session (scheduled for after the current September Auction date) or via a Special Session (at any time, if called by the Governor for that purpose). 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 Sangamon County, Illinois issued an injunction against the use of the Section 28.5 rulemaking procedures and the rule is being considered under normal procedures. In accordance with the revised rulemaking schedule, the Illinois EPA presented its witnesses in support of its proposed mercury rule during the initial hearing in June, 2006. Industry representatives prefiled their written testimony in July, 2006 and will present their case opposing the rule in a hearing scheduled to begin on August 14, 2006. The Illinois EPA and Ameren filed a Joint Statement with the IPCB in late July supporting a Multi-Pollutant Alternative to the Illinois Mercury Rule that significantly extends the schedule for compliance with the proposed new mercury standard while adding new requirements for the control of sulfur dioxide and nitrogen oxides emissions. Other Illinois generators continue to discuss potential alternatives with the Illinois EPA. After hearings are completed, the IPCB will transmit the proposed rule to the Joint Committee on Administrative Rules (JCAR), which will ensure the proposed rule is consistent with state law and the views of the legislature. The IPCB is expected to issue a final mercury rule by the end of this year.

On May 25, 2006, the Governor of New York announced plans to regulate mercury emissions from coal-fired power plants by reducing emissions by approximately 50% by 2010 and 90% by 2015. NYSDEC is expected to issue a proposed rule in the near-term. The proposed rule would establish a 72 lb/yr mercury emission limit for the Danskammer generating units beginning in January 2010. Beginning in January 2015, the rule would impose an emission rate limit of 0.6 pounds of mercury per trillion Btu for all affected generating units. The proposed rule would not allow trading of mercury emission allowances.

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.

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. Accordingly, these entities have continuously had market-based rate authority. Our next triennial market power analysis is currently due June 16, 2008. However, FERC is considering adoption of a regional approach for the submission of triennial reviews that could alter this due date.

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

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(Unaudited)

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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 us 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.

Share-Based Compensation. 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 six months ended June 30, 2006 and 2005:

	Six Months Ended June 30,	
	2006	**2005**
Dividends		
Expected volatility (historical)	48.8%	84.1%
Risk-free interest rate	5.1%	4.2%
Expected option life	6 Years	10 Years

The expected volatility was calculated based on a ten-year historical volatility of our stock price in 2005 and beginning in first quarter 2006, we used a three-year historical volatility. The risk-free interest rate was calculated based upon observed interest rates appropriate for the term of our employee stock options. Currently, we calculate the expected option life 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.

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 $1.47 per share to $56.98 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, had a 10-year term, and expired in May 2006. All option grants are vested.

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DYNEGY INC.

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(Unaudited)

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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. 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. 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 2006, we granted stock-based compensation awards that cliff vest after three years based on our cumulative operating cash flows for 2006-2008. Compensation expense recorded in the three and six months ended June 30, 2006 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

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(Unaudited)

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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 June 30, 2006 are summarized below:

	Options (in thousands)	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	(1,119)	$ 3.48		
Forfeited or expired	(2,601)	$ 3.91		
Outstanding at June 30, 2006	8,862	$ 13.53	6.3	$ 5.4
Vested and unvested expected to vest at June 30, 2006	8,031	$ 14.43	5.9	$ 4.9
Exercisable at June 30, 2006	5,136	$ 19.86	3.9	$ 2.9

The weighted average grant-date fair value of options granted during the six months ended June 30, 2006 and 2005 was $2.61 and $3.66, respectively. The total intrinsic value of options exercised for the six-month periods ended June 30, 2006 and 2005 was $3 million and zero, respectively.

Restricted stock activity for the six months ended June 30, 2006 was as follows:

	Number of Shares (in thousands)	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2005	1,239	$ 4.40
Granted	1,311	$ 4.88
Vested	(241)	$ 4.38
Forfeited	(89)	$ 4.78
Nonvested at June 30, 2006	2,220	$ 4.67

Compensation expense related to options granted and restricted stock awarded totaled $2 million for both the quarters ended June 30, 2006 and 2005 and $4 million for six month periods ended June 30, 2006 and 2005. Tax benefits for compensation expense related to options granted and restricted stock awarded totaled $1 million for the quarters ended June 30, 2006 and 2005, and $1 million for both the six months ended June 30, 2006 and 2005. We recognize compensation expense ratably over the vesting period of the respective awards. As of June 30, 2006, $12 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 2.4 years. The total fair value of shares vested was zero for the quarters ended June 30, 2006 and 2005, and $4 million and $3 million for the six months ended June 30, 2006 and 2005, respectively. We did not capitalize nor use cash to settle any share-based compensation in the six months ended June 30, 2006.

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DYNEGY INC.

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(Unaudited)

For the Interim Periods Ended June 30, 2006 and 2005

Cash received from option exercises for the three and six months ended June 30, 2006 was zero and $4 million, respectively. The tax benefit realized for the additional tax deduction from share-based payment awards totaled $1 million for the six months ended June 30, 2006.

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

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
	2006	2005	2006	2005
	(in millions)			
Service cost benefits earned during period	$ 3	$ 3	$ 1	$
Interest cost on projected benefit obligation	3	2	1	1
Expected return on plan assets	(3)	(2)		
Recognized net actuarial loss		1		
Total net periodic benefit cost	$ 3	$ 4	$ 2	$ 1

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
	2006	2005	2006	2005
	(in millions)			
Service cost benefits earned during period	$ 5	$ 6	$ 2	$ 1
Interest cost on projected benefit obligation	5	4	2	2
Expected return on plan assets	(5)	(4)		
Recognized net actuarial loss	1	2		
Net periodic benefit cost	6	8	4	3
Additional cost due to curtailment	2			
Total net periodic benefit cost	$ 8	$ 8	$ 4	$ 3

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

Contributions. In 2006, we expect to contribute approximately $15 million to our pension plans, $12 million of which we expect to pay in September 2006, and less than $1 million to our other postretirement benefit plans in 2006. During the first half of 2006, we made $2 million in contributions.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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Note 13 Income Taxes

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in millions, except rates)			
Income tax benefit	$ 118	$ 41	$ 115	$ 215
Effective tax rate	36%	27%	36%	35%

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 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 and adjustments to the effective state tax rate.

Texas Margin Tax. In May 2006, Texas enacted a new law that substantially changes the state s tax system. The law replaces the taxable-capital and earned-surplus components of its franchise tax with a new franchise tax that is based on modified gross revenue. This new franchise tax is referred to as the Margin Tax and will significantly affect the financial reporting of a wide range of enterprises that have operations in Texas. As a result of the new law, which becomes effective January 1, 2007, we established a deferred tax liability of $2 million related to our Texas operations. We removed the deferred tax asset of less than $1 million related to existing Texas net operating losses under the current franchise tax law since we do not forecast a Texas income tax liability in 2006. The effect of the Texas law change produced a total charge of $2 million.

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.

DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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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 and six months ended June 30, 2006 and 2005 is presented below:

Dynegy s Segment Data for the Three Months Ended June 30, 2006

(in millions)

	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other and Eliminations	Total
Unaffiliated revenues:							
Domestic	$ 228	$ 95	$ 68	$ 9	$	$	$ 400
Other		31		8			39
	228	126	68	17			439
Intersegment revenues		(1)		1			
Total revenues	$ 228	$ 125	$ 68	$ 18	$	$	$ 439
Depreciation and amortization	$ (43)	$ (6)	$ (6)	$	$	$ (2)	$ (57)
Impairment and other charges			(9)				(9)
Operating income (loss)	$ 71	$	$ (10)	$ (8)	$	$ (34)	$ 19
Other items, net		2	1	(2)		9	10
Interest expense							(354)
Loss from continuing operations before income taxes							(325)
Income tax benefit							118
Loss from continuing operations							(207)
Loss from discontinued operations, net of taxes							
Net loss							$ (207)
Identifiable assets:							
Domestic	$ 4,722	$ 1,349	$ 881	$ 462	$ 30	$ 128	$ 7,572
Other		16	2	99			117
Total	$ 4,722	$ 1,365	$ 883	$ 561	$ 30	$ 128	$ 7,689
Unconsolidated investments	$	$	$ 4	$	$	$	$ 4
Capital expenditures	$ (25)	$ (4)	$ (9)	$	$	$ (3)	$ (41)

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended June 30, 2006 and 2005

Dynegy s Segment Data for the Three Months Ended June 30, 2005

(in millions)

	Power Generation						
	GEN-MW	**GEN-NE**	**GEN-SO**	**CRM**	**NGL**	**Other and Eliminations**	**Total**
Unaffiliated revenues:							
Domestic	$ 225	$ 125	$ 78	$ (3)	$	$	$ 425
Other		30		4			34
	225	155	78	1			459
Intersegment revenues		(4)	(13)	17			
Total revenues	$ 225	$ 151	$ 65	$ 18	$	$	$ 459
Depreciation and amortization	$ (40)	$ (5)	$ (5)	$	$	$ (4)	$ (54)
Operating income (loss)	$ 45	$ (15)	$ (11)	$ (15)	$	$ (68)	$ (64)
Earnings from unconsolidated investments	1		3				4
Other items, net	(1)	2	1	(1)		5	6
Interest expense							(96)
Loss from continuing operations before income taxes							(150)
Income tax benefit							41
Loss from continuing operations							(109)
Income from discontinued operations, net of taxes							134
Net income							$ 25
Identifiable assets:							
Domestic	$ 5,029	$ 1,447	$ 1,104	$ 927	$ 1,542	$ 570	$ 10,619
Other			5	134	2		141
Total	$ 5,029	$ 1,447	$ 1,109	$ 1,061	$ 1,544	$ 570	$ 10,760
Unconsolidated investments	$ 63	$	$ 227	$	$ 78	$	$ 368
Capital expenditures	$ (20)	$ (4)	$ (1)	$	$ (13)	$ (1)	$ (39)

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Interim Periods Ended June 30, 2006 and 2005

Dynegy s Segment Data for the Six Months Ended June 30, 2006

(in millions)

	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other and Eliminations	Total
Unaffiliated revenues:							
Domestic	$ 484	$ 228	$ 179	$ 49	$	$	$ 940
Other		91		8			99
	484	319	179	57			1,039
Intersegment revenues		(2)		2			
Total revenues	$ 484	$ 317	$ 179	$ 59	$	$	$ 1,039
Depreciation and amortization	$ (83)	$ (12)	$ (12)	$	$	$ (10)	$ (117)
Impairment and other charges			(9)			(2)	(11)
Operating income (loss)	$ 169	$ 26	$ (23)	$ 6	$	$ (81)	$ 97
Earnings from unconsolidated investments			2				2
Other items, net		4	1	(1)		26	30
Interest expense							(452)
Loss from continuing operations before income taxes							(323)
Income tax benefit							115
Loss from continuing operations							(208)
Income from discontinued operations, net of taxes							1
Cumulative effect of change in accounting principle, net of taxes							1
Net loss							$ (206)
Identifiable assets:							
Domestic	$ 4,722	$ 1,349	$ 881	$ 462	$ 30	$ 128	$ 7,572
Other		16	2	99			117
Total	$ 4,722	$ 1,365	$ 883	$ 561	$ 30	$ 128	$ 7,689
Unconsolidated investments	$	$	$ 4	$	$	$	$ 4
Capital expenditures	$ (36)	$ (7)	$ (12)	$	$	$ (4)	$ (59)

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DYNEGY INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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Dynegy s Segment Data for the Six Months Ended June 30, 2005

(in millions)

	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other and Eliminations	Total
Unaffiliated revenues:							
Domestic	$ 439	$ 284	$ 150	$ 60	$	$	$ 933
Other		30		(42)			(12)
	439	314	150	18			921
Intersegment revenues	1	(2)	(25)	26			
Total revenues	$ 440	$ 312	$ 125	$ 44	$	$	$ 921
Depreciation and amortization	$ (77)	$ (10)	$ (10)	$ (1)	$	$ (11)	$ (109)
Operating income (loss)	$ 106	$ (4)	$ (23)	$ (207)	$	$ (321)	$ (449)
Earnings from unconsolidated investments	1		6				7
Other items, net	(1)	2	1			7	9
Interest expense							(185)
Loss from continuing operations before income taxes							(618)
Income tax benefit							215
Loss from continuing operations							(403)
Income from discontinued operations, net of taxes							166
Net loss							$ (237)
Identifiable assets:							
Domestic	$ 5,029	$ 1,447	$ 1,104	$ 927	$ 1,542	$ 570	$ 10,619
Other			5	134	2		141
Total	$ 5,029	$ 1,447	$ 1,109	$ 1,061	$ 1,544	$ 570	$ 10,760
Unconsolidated investments	$ 63	$	$ 227	$	$ 78	$	$ 368
Capital expenditures	$ (57)	$ (7)	$ (1)	$	$ (23)	$ (5)	$ (93)

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Note 15 Subsequent Events

On July 15, 2006, we redeemed all of our remaining 2008 Notes, at a redemption price of 103% of the principal amount, plus accrued and unpaid interest to the redemption date. Please read Note 7 Debt Second Priority Senior Secured Notes for further discussion.

On July 21, 2006, DHI executed and consummated an Exchange Agreement with the Reservoir Entities to exchange the Sithe Debt for the Additional Notes. Please read Note 7 Debt Sithe Subordinated Debt Exchange for further discussion.

DYNEGY INC.

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

For the Interim Periods Ended June 30, 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 legacy physical gas supply contracts and gas transportation contracts and remaining legacy 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

During the second quarter 2006 we continued to focus on our key objectives of (i) reducing existing debt obligations, (ii) reducing interest expense, (iii) reducing near- to medium-term debt maturities, (iv) maintaining adequate liquidity and (v) enhancing capital structure flexibility. To that end we have initiated and/or completed the following transactions since the first quarter 2006.

Sithe Subordinated Debt Exchange. On July 21, 2006, DHI issued $297 million principal amount of additional 8.375% Senior Unsecured Notes due 2016 in exchange for all $419 million of outstanding Sithe subordinated debt.

Redemption of Second Priority Notes 2008. On July 15, 2006, DHI redeemed all of its remaining 2008 Notes, at a redemption price of 103% of the principal amount, plus accrued and unpaid interest to the redemption date.

Public Offering of Class A Common Stock. On May 26, 2006, we completed a public offering of 40.25 million shares of our Class A common stock, including 5.25 million shares purchased pursuant to an underwriters over-allotment option. We received net proceeds from the offering, after payment of underwriting fees, of approximately $178 million. We used these proceeds, together with cash on hand and the DHI Dividend, to pay the redemption price for our Series C convertible preferred stock as discussed below.

Redemption of Series C Convertible Preferred Stock. In connection with the closing of the public stock offering, we redeemed from CUSA all 8 million shares of our outstanding Series C convertible preferred stock for a cash purchase price of $400 million (equal to the aggregate liquidation preference of the Series C convertible preferred stock), plus accrued and unpaid dividends totaling approximately $6.3 million. We used the DHI Dividend, together with the net proceeds of the public stock offering and cash on hand, to consummate the redemption.

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Rockingham Sale. On May 22, 2006, we announced the sale of our Rockingham peaking facility to a Duke Energy subsidiary for $195 million. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Rockingham for further discussion.

Convertible Debenture Exchange. On May 15, 2006, we consummated an offer to convert all $225 million of our outstanding 4.75% Convertible Subordinated Debentures due 2023 into shares of our common stock and cash.

Other Liability Management. As mentioned above, during the first half of 2006, we initiated and/or completed several transactions consistent with our key objectives. We believe that these transactions will better align our capital structure with the inherently cyclical nature of our power generation business and enhance our ability to benefit from the anticipated future market recovery and to access the capital markets. In addition to the above mentioned transactions, 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).

- On April 12, 2006, we completed a tender offer and consent solicitation (the SPN Tender Offer) in which we purchased $151 million of our $225 million outstanding Second Priority Senior Secured Floating Rate Notes due 2008 (the 2008 Notes), $614 million 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 million aggregate principal amount of our 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, increased the revolving credit facility to $470 million and added a $200 million letter of credit facility funded with term loan proceeds.

As a result of the above transactions and the elimination of the Sterlington toll in first quarter 2006, we reduced our debt and other obligations by approximately $2 billion. The reduction in debt will result in a corresponding reduction in future interest expense.

Operational Highlights

Scheduled Outages and Maintenance. In the Midwest, we completed our planned Spring 2006 outages at our Havana and Hennepin facilities in a safe and efficient manner and both major outages were completed ahead of schedule. In the Northeast, we successfully completed routine maintenance inspections and repairs as well as other routine balance of plant activities. In the South, we completed routine maintenance and the first of several scheduled environmental upgrades at our CoGen Lyondell facility.

Safety Performance. Safety is a foremost priority for conducting our business. Safety permeates the way we act and work, all the way from our Guiding Principles, to the training and briefings that we do on a daily basis, to the work plans created for each job that we do in the plants. We have a safety organization in place that is responsible for the training, managing, and oversight of our safety efforts, but our principal tenet is that each and every employee is responsible for his/her own safety, and for that of others with whom they work, on a continual basis. We use standard industry measurements relating to reportable and lost-time incident rates to evaluate our safety performance. For the first half of 2006, incidents were down period over period.

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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, 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.

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 August 4, 2006, June 30, 2006 and December 31, 2005:

	August 4, 2006	June 30, 2006	December 31, 2005
		(in millions)	
By Segment:			
Generation	$ 221	$ 167	$ 280
Customer risk management	65	56	91
Other	8	8	10
Total	$ 294	$ 231	$ 381
By Type:			
Cash (1)	$ 59	$ 55	$ 122
Letters of Credit	235	176	259
Total	$ 294	$ 231	$ 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 June 30, 2006 is primarily due to a return of collateral postings of approximately $113 million in our generation business and $35 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 $44 million as a result of the sale of our 50% interest in West Coast Power to NRG, completed on March 31, 2006. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations West Coast Power for further discussion. The increase in collateral postings from June 30, 2006 to August 4, 2006 is primarily due to increased prices as well as hedging activities.

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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. 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.

Our contractual obligations and contingent financial commitments have changed since December 31, 2005 as a result of the termination of the Sterlington long-term wholesale power tolling contract with Quachita Power. Under that agreement, which closed on March 7, 2006, 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.

Please also read Note 7 Debt for a discussion of changes in our debt obligations. As of June 30, 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 second quarter 2006 and do not foresee a declaration of dividends in the near term.

On May 26, 2006, we completed the redemption of our Series C Preferred Stock (which had an aggregate liquidation preference of $400 million), which eliminated the associated $22 million annual preferred dividend. Please read Note 8 Related Party Transaction Series C Convertible Preferred Stock for further discussion.

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 August 4, 2006, June 30, 2006 and December 31, 2005:

	August 4, 2006	June 30, 2006	December 31, 2005
		(in millions)	
Total revolver capacity	$ 470(1)	$ 470(1)	$
Total additional letter of credit capacity, plus 3% reserve requirement	194	194	325
Outstanding letters of credit under revolving credit facility	(235)	(176)	(259)
Unused revolver capacity	429	488	66
Cash	286(2)(3)	358(2)(3)	1,549(2)
Total available liquidity	$ 715	$ 846	$ 1,615

(1) In March and April 2006, we amended and restated the credit facility. Please read Note 7 Debt for further discussion.

(2) The August 4, 2006, June 30, 2006 and December 31, 2005 amounts include approximately $36 million, $16 million and $21 million, respectively, of cash that remains in Europe and $22 million, $21 million and $19 million, respectively, of cash that remains in Canada.

(3) The decrease in cash balance since December 31, 2005 was primarily due to the debt repayments associated with our liability management activities. Please read Note 7 Debt for further discussion.

Cash Flows from Operations. We had operating cash outflows of $368 million for the six months ended June 30, 2006. This consisted of $271 million in operating cash flows from our power generation business, offset by $392 million of cash outflows relating to our customer risk management business and $247 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.

Our future operating cash flows will vary based on a number of factors, many of which are beyond our control, including the price of gas and its correlation to power prices, the cost of coal and the value of ancillary services. 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 August 4, 2006 and June 30, 2006, we had cash on hand of $286 million and $358 million, respectively, as compared to $1,549 million at the end of 2005. This decrease in cash on hand to June 30, 2006 as compared to the end of 2005 is primarily attributable to our liability management activities. Please read Note 7 Debt for further discussion. The decrease in cash balance on August 4, 2006 from June 30, 2006 was primarily due to the redemption of all of DHI s remaining 2008 Notes.

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. The Fourth Senior Secured 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 August 4, 2006, we had $235 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.

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External Liquidity Sources

Our primary external liquidity sources are proceeds from asset sales and other types of capital-raising transactions.

Asset Sale Proceeds. On May 21, 2006, we entered into an agreement with Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC (a subsidiary of Duke Energy) for the sale of our Rockingham facility, a peaking facility in North Carolina, for $195 million in cash. The transaction is expected to close in the fourth quarter 2006, subject to obtaining certain regulatory approvals and satisfaction of customary closing conditions. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Rockingham for further discussion. The proceeds from the sale would be used to repay our borrowings under the $150 million Term Loan. Please read Note 7 Debt Senior Secured Credit Facility for further discussion of the Term Loan.

In March 2006, we completed our ownership exchange transaction with NRG 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.

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 other than Rockingham, 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 maintain a capital structure that is closely aligned with the cash-generating potential of our asset-based business, which is subject to cyclical changes in commodity prices, we will continuously explore additional sources of external liquidity both in the near- and long-term. The timing of any transaction may be impacted by 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 our recent 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. We continue to focus on safety and its impact on our performance and results. 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 safe, efficient and 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

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are currently pursuing and expect to continue to pursue opportunities that may expand our existing facilities, achieve operating efficiencies or provide greater scale, scope and diversity for our generation portfolio.

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

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- and six-month periods ended June 30, 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 legacy physical gas supply contracts and gas transportation contracts and remaining legacy 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.

Three Months Ended June 30, 2006 and 2005

Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for the three-month periods ended June 30, 2006 and 2005, respectively:

Three Months Ended June 30, 2006

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 71	$	$ (10)	$ (8)	$ (34)	$ 19
Earnings from unconsolidated investments						
Other items, net		2	1	(2)	9	10
Interest expense						(354)
Loss from continuing operations before income taxes						(325)
Income tax benefit						118
Loss from continuing operations						(207)
Loss from discontinued operations, net of taxes						
Net loss						$ (207)

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Three Months Ended June 30, 2005

	Power Generation					
	GEN-MW	GEN-NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 45	$ (15)	$ (11)	$ (15)	$ (68)	$ (64)
Earnings from unconsolidated investments	1		3			4
Other items, net	(1)	2	1	(1)	5	6
Interest expense						(96)
Loss from continuing operations before income taxes						(150)
Income tax benefit						41
Loss from continuing operations						(109)
Income from discontinued operations, net of taxes						134
Net income						$ 25

The following table provides summary segmented operating statistics for the three months ended June 30, 2006 and 2005, respectively:

	Three Months Ended June 30,	
	2006	2005
GEN-MW		
Million Megawatt Hours Generated Gross and Net	4.9	5.5
Average Actual On-Peak Market Power Prices ($/MWh) (1):		
Cinergy (Cin Hub)	$ 53	$ 54
Commonwealth Edison (NI Hub)	$ 53	$ 52
GEN-NE		
Million Megawatt Hours Generated Gross and Net	0.9	1.4
Average Actual On-Peak Market Power Prices ($/MWh) (1):		
New York Zone G	$ 73	$ 78
New York Zone A	$ 58	$ 62
GEN-SO		
Million Megawatt Hours Generated Gross	0.9	1.7
Million Megawatt Hours Generated Net	0.8	1.4
Average Actual On-Peak Market Power Prices ($/MWh) (1):		
Southern	$ 57	$ 57
ERCOT	$ 70	$ 68
Average natural gas price Henry Hub ($/MMBtu) (2)	$ 6.53	$ 6.94

(1) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices realized by the company.

(2) Reflects the average of daily quoted prices for the periods presented and does not necessarily reflect prices realized by the company.

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The following tables summarize significant items on a pre-tax basis, with the exception of the 2005 tax item, affecting net loss for the periods presented.

	Three Months Ended June 30, 2006						
	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other	Total
	(in millions)						
Debt conversion costs	$	$	$	$	$	$ (247)	$ (247)
Acceleration of financing costs						(33)	(33)
Legal and settlement charges				(16)		(2)	(18)
Total	$	$	$	$ (16)		$ (282)	$ (298)

	Three Months Ended June 30, 2005						
	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other	Total
	(in millions)						
Legal and settlement charges	$	$	$	$	$	$ (31)	$ (31)
Independence toll settlement charge				13			13
Discontinued operations				1	35		36
Taxes						99	99
Total	$	$	$	$ 14	$ 35	$ 68	$ 117

Operating Income (Loss)

Operating income was $19 million for the three months ended June 30, 2006, compared to a loss of $64 million for the three months ended June 30, 2005.

Power Generation Midwest Segment. Operating income for GEN-MW was $71 million for the three months ended June 30, 2006, compared to $45 million for the three months ended June 30, 2005. GEN-MW results for the three months ended June 30, 2005 included general and administrative expenses of $9 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please read 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 $109 million for the three months ended June 30, 2006 from $94 million for the three months ended June 30, 2005. Average actual on-peak prices in CinHub/Cinergy pricing region decreased from $53.65 per MWh in the second quarter 2005 to $52.51 per MWh for the second quarter 2006. Generated volumes decreased from 5.5 million MWh for the second quarter 2005 to 4.9 million MWh for the same period in 2006. Despite the decrease in prices and volume, our results increased due to higher realized prices. Results from our coal-fired generating units were negatively impacted by the AmerenIP contract during 2005, preventing us from recognizing the full benefit of market prices during the 2005 period. During certain peak periods in 2005, Ameren took higher volumes than we expected, resulting in a need to purchase power at market prices in order to satisfy our obligations for forward sales previously made to other third parties. We did not experience a similar situation under the AmerenIP contract in 2006. Offsetting this increase were operating expense increases of $4 million, due largely to scheduled maintenance.

GEN-MW s results for the three months ended June 30, 2006 include $1 million of mark-to-market losses, compared with $10 million of income for the three months ended June 30, 2005. This is primarily related to options and other transactions that economically hedged our generation assets, and were not designated as cash flow hedges.

Results for our gas-fired peaking facilities in GEN-MW improved by $5 million, from zero in the second quarter 2005 to $5 million for the same period in 2006, largely resulting from increased capacity fees in 2006 at our Renaissance facility. Results also benefited from our increased ownership in the Rocky Road facility and the associated increase in capacity revenues.

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Depreciation expense increased slightly, from $40 million in 2005 to $43 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.

Power Generation Northeast Segment. Operating income for GEN-NE was zero for the three months ended June 30, 2006, compared to a loss of $15 million for the three months ended June 30, 2005. GEN-NE for the three months ended June 30, 2005 included general and administrative expenses of $5 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please read Results of Operations Operating Income (Loss) Other for a consolidated discussion of general and administrative expenses.

Results from our Northeast facilities were $6 million for the three months ended June 30, 2006, compared with a loss of $4 million for three months ended June 30, 2005.

Results for our Roseton and Danskammer facilities increased approximately $7 million. Average on-peak prices for Zone G, the market served by these two facilities, decreased from $77.78 per MWh in 2005 to $72.76 per MWh in 2006. Generated volumes decreased from 0.9 million MWh for the second quarter 2005 to 0.6 million MWh for the same period in 2006. Despite the lower prices and volumes, results increased primarily due to increased capacity sales and higher realized margins from Danskammer. This was partially offset by net mark-to-market losses of $7 million for the second quarter 2006, related to financial transactions not designated as cash flow hedges. Second quarter 2005 results included mark-to-market losses of $6 million.

Results for our Independence facility increased approximately $3 million. Average on-peak prices for Zone A decreased from $62.28 per MWh in 2005 to $58.04 per MWh in 2006. Generated volumes decreased from 0.6 million MWh for the second quarter 2005 to 0.3 million MWh for the same period in 2006. Despite the lower prices and volumes, results increased due to increased merchant capacity payments and higher realized prices. Operating expenses were also lower by $1 million, due to reduced volumes generated.

Depreciation expense increased slightly, from $5 million in 2005 to $6 million in 2006.

Power Generation South Segment. Operating loss for GEN-SO was $10 million for three months ended June 30, 2006, compared to a loss of $11 million for the three months ended June 30, 2005. GEN-SO for the three months ended June 30, 2005, included general and administrative expenses of $3 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please read Results of Operations Operating Income (Loss) Other for a consolidated discussion of general and administrative expenses.

Results from our ERCOT facility remained unchanged with income of approximately $2 million in both 2005 and 2006. Power prices increased slightly from 2005 to 2006. Included in the 2006 results are $4 million of mark-to-market gains, which relate to hedge ineffectiveness in the ERCOT region. Results were offset by lower volumes in 2006 as compared to 2005

Results from our southeast peaker assets increased slightly, from $2 million in 2005 to $3 million in 2006. These improved results are due to additional capacity agreements for the Rockingham and Calcasieu facilities and slightly improved spark spreads in the region resulting in increased dispatch.

Depreciation expense was $6 million for the three months ended June 30, 2006 and $5 million for the three months ended June 30, 2005. In addition, during the second quarter 2006, we recorded a $9 million impairment of our Rockingham facility, resulting from the pending sale. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Rockingham for further discussion. Additionally, our 2005 results include a $7 million charge associated with the write-off of an environmental project.

CRM. Operating loss for the CRM segment was $8 million for the three months ended June 30, 2006, compared to operating loss of $15 million for the three months ended June 30, 2005. Our 2006 loss was driven primarily by a $16 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. This was offset by the release of a disputed liability based on management s estimate of the likely outcome as well as mark-to-market gains on our legacy emissions positions.

Results for 2005 reflect the negative impact of fixed payments on our Gregory and Sterlington power tolling arrangements in excess of realized margins on power generated and sold, as well as mark-to-market losses on our legacy coal, gas and power positions. This was partially offset by a $13 million benefit resulting from a revision to our purchase price allocation in connection with our purchase of Sithe Energies in the first quarter 2005.

Other. Other operating loss was $34 million for the three months ended June 30, 2006, compared to a loss of $68 million for the three months ended June 30, 2005. Results for second quarter 2006 include approximately $35 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 June 30, 2005 included general and administrative expenses of $82 million.

Consolidated general and administrative expenses decreased from $82 million for the three months ended June 30, 2005 to $51 million for the three months ended June 30, 2006, primarily due to a $31 million charge associated with settlement of our shareholder class action litigation in 2005, as well as decreases in compensation and benefits costs and professional and legal fees from 2005 to 2006, offset by $18 million in legal reserves recorded in 2006, of which $16 million are reflected in our CRM segment.

Earnings from Unconsolidated Investments

Earnings from unconsolidated investments for the three months ended June 30, 2006 of zero included the GEN-SO investment in Black Mountain. Earnings from unconsolidated investments of $4 million for the three months ended June 30, 2005 includes results from GEN-SO investments in both Black Mountain and West Coast Power.

Other Items, Net

Other items, net totaled $10 million of income for the three months ended June 30, 2006, compared to $6 million of income for the three months ended June 30, 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 and debt conversion costs totaled $354 million for the three months ended June 30, 2006, compared to $96 million for the three months ended June 30, 2005. The increase is primarily attributable to debt conversion costs and acceleration of financing costs resulting from our liability management program executed in the second quarter of 2006. Please read Note 7 Debt for further discussion.

Income Tax Benefit

We reported an income tax benefit from continuing operations of $118 million for the three months ended June 30, 2006, compared to an income tax benefit from continuing operations of $41 million for the three months ended June 30, 2005. The 2006 effective tax rate was 36%, compared to 27% in 2005. 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. Additionally, our overall effective tax rate on continuing operations was different than the statutory rate of 35% in 2005 due primarily to the nondeductible portion of the charge associated with the shareholder litigation settlement, offset by changes in the valuation allowances.

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Discontinued Operations

Income (Loss) 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.

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

Three Months Ended June 30, 2006

	U.K. CRM	NGL (in millions)	Total
Operating loss included in income from discontinued operations	$ (3)	$	$ (3)
Other items, net included in income from discontinued operations	1		1
Loss from discontinued operations before taxes			(2)
Income tax benefit			2
Income from discontinued operations			$

Three Months Ended June 30, 2005

	U.K. CRM	NGL (in millions)	Total
Operating income (loss) included in income from discontinued operations	$ (1)	$ 53	$ 52
Earnings from unconsolidated investments included in income from discontinued operations		2	2
Other items, net included in income from discontinued operations	2	(6)	(4)
Interest expense included in income from discontinued operations			(14)
Income from discontinued operations before taxes			36
Income tax benefit			98
Income from discontinued operations			$ 134

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 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 June 30, 2006 the pre-tax loss from discontinued operations was $2 million (zero after-tax). Our U.K. CRM segment includes a loss of $2 million for the three months ended June 30, 2006, associated with the settlement of an outstanding contract. During the three months ended June 30, 2005, pre-tax income from discontinued operations of $36 million ($134 million after-tax) included $35 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 $14 million during the three months ended June 30, 2006 and 2005, respectively.

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Income Tax Benefit From Discontinued Operations. We recorded an income tax benefit from discontinued operations of $2 million during the three months ended June 30, 2006, compared to an income tax benefit from discontinued operations of $98 million during the three months ended June 30, 2005. The income tax benefit in 2005 included a $112 million benefit associated with reducing a valuation allowance related to our capital loss carryforward, which primarily relates to our third quarter 2002 sale of NNG. We reduced the valuation allowance related to our capital loss carryforward as a result of capital gains expected to be recognized from our sale of DMSLP. For further information regarding the sale, please see Note 3 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids. The effective rates for the three months ended June 30, 2006 and 2005, adjusting for the reduction of the valuation allowance in 2005, were 100% and 39%, respectively. FIN No. 18, Accounting for Income Taxes in Interim Periods an interpretation of APB Opinion No. 28 proscribes a detailed methodology of allocating income taxes between continuing and discontinued operations. This methodology often results in an effective rate for discontinued operations significantly different from the statutory rate of 35%.

Six Months Ended June 30, 2006 and 2005

Summary Financial Information. The following tables provide summary financial data regarding our consolidated and segmented results of operations for the six-month periods ended June 30, 2006 and 2005, respectively:

Six Months Ended June 30, 2006

	Power Generation					
	GEN-MW	GEN - NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 169	$ 26	$ (23)	$ 6	$ (81)	$ 97
Earnings from unconsolidated investments			2			2
Other items, net		4	1	(1)	26	30
Interest expense						(452)
Loss from continuing operations before income taxes						(323)
Income tax benefit						115
Loss from continuing operations						(208)
Income from discontinued operations, net of taxes						1
Cumulative effect of change in accounting principle, net of taxes						1
Net loss						$ (206)

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Six Months Ended June 30, 2005

	Power Generation					
	GEN-MW	GEN - NE	GEN-SO	CRM	Other and Eliminations	Total
			(in millions)			
Operating income (loss)	$ 106	$ (4)	$ (23)	$ (207)	$ (321)	$ (449)
Earnings from unconsolidated investments	1		6			7
Other items, net	(1)	2	1		7	9
Interest expense						(185)
Loss from continuing operations before income taxes						(618)
Income tax benefit						215
Loss from continuing operations						(403)
Income from discontinued operations, net of taxes						166
Net loss						$ (237)

The following table provides summary segmented operating statistics for the six months ended June 30, 2006 and 2005, respectively:

	Six Months Ended June 30, 2006	2005
GEN-MW		
Million Megawatt Hours Generated Gross and Net	10.3	10.5
Average Actual On-Peak Market Power Prices ($/MWh) (1):		
Cinergy (Cin Hub)	$ 51	$ 52
Commonwealth Edison (NI Hub)	$ 52	$ 50
GEN-NE		
Million Megawatt Hours Generated Gross and Net	1.9	3.5
Average Actual On-Peak Market Power Prices ($/MWh) (1):		
New York Zone G	$ 74	$ 74
New York Zone A	$ 59	$ 60
GEN-SO		
Million Megawatt Hours Generated Gross	2.2	3.5
Million Megawatt Hours Generated Net	2.2	2.7
Average Actual On-Peak Market Power Prices ($/MWh) (1):		
Southern	$ 56	$ 53
ERCOT	$ 63	$ 60
Average natural gas price Henry Hub ($/MMBtu) (2)	$ 7.14	$ 6.67

(1) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices realized by the company.

(2) Reflects the average of daily quoted prices for the periods presented and does not necessarily reflect prices realized by the company.

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The following tables summarize significant items on a pre-tax basis, with the exception of the 2005 tax item, affecting net loss for the periods presented.

	Six Months Ended June 30, 2006						
	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other	Total
	(in millions)						
Debt conversion costs	$	$	$	$	$	$ (247)	$ (247)
Acceleration of financing costs						(34)	(34)
Legal and settlement charges				(31)		(2)	(33)
Total	$	$	$	$ (31)		$ (283)	$ (314)

	Six Months Ended June 30, 2005						
	Power Generation						
	GEN-MW	GEN-NE	GEN-SO	CRM	NGL	Other	Total
	(in millions)						
Legal and settlement charges	$	$	$	$	$	$ (253)	$ (253)
Independence toll settlement charge				(170)			(170)
Discontinued operations				5	81		86
Taxes						112	112
Total	$	$	$	$ (165)	$ 81	$ (141)	$ (225)

Operating Income (Loss)

Operating income was $97 million for the six months ended June 30, 2006, compared to a loss of $449 million for the six months ended June 30, 2005.

Power Generation Midwest Segment. Operating income for GEN-MW was $169 million for the six months ended June 30, 2006, compared to $106 million for the six months ended June 30, 2005. GEN-MW results for the six months ended June 30, 2005 included general and administrative expenses of $17 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please read 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 $244 million for the six months ended June 30, 2006 from $201 million for the six months ended June 30, 2005. Average actual on-peak prices in CinHub/Cinergy pricing region decreased from $51.53 per MWh in the six months ended June 30, 2005 to $50.73 per MWh for the six months ended June 30, 2006. Generated volumes decreased slightly, from 10.5 million MWh in the six months ended June 30, 2005 to 10.3 million MWh for the same period in 2006. Despite the slight decrease in output, the increase in results was primarily driven by higher realized power prices. We realized higher power prices in the first quarter 2006 as we settled forward power sales. Additionally, results from our coal-fired generating units were negatively impacted by the AmerenIP contract during the second quarter 2005, preventing us from recognizing the full benefit of market prices during the 2005 period. During certain peak periods in 2005, Ameren took higher volumes than we expected, resulting in a need to purchase power at market prices in order to satisfy our obligations for forward sales previously made to other third-parties. We did not experience a similar situation under the AmerenIP contract in 2006.

GEN-MW s results for the first six months of 2006 include mark-to-market losses of $1 million, compared with income of $9 million for the six months ended June 30, 2005. This is primarily related to options and other transactions that economically hedged our generation assets, and were not designated as cash flow hedges.

Results for our gas-fired peaking facilities in GEN-MW improved by $10 million, increasing from a loss of $2 million for the first six months of 2005 to positive earnings of $8 million for the same period in 2006. This

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improvement was the result of higher volume as the MISO increased dispatch of these units during first quarter 2006 to maintain system reliability. In addition, we recognized increased capacity fees in the second quarter 2006, particularly at our Renaissance facility.

Depreciation expense increased slightly, from $77 million in 2005 to $83 million in 2006 as a result of capital projects placed into service in 2005. This was primarily related to the conversion of the Havana facility to burn PRB coal.

Power Generation Northeast Segment. Operating income for GEN-NE was $26 million for the six months ended June 30, 2006, compared to a loss of $4 million for the six months ended June 30, 2005. GEN-NE for the six months ended June 30, 2005 included general and administrative expenses of $11 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please read Results of Operations Operating Income (Loss) Other for a consolidated discussion of general and administrative expenses.

Results from our Northeast facilities were $38 million for the six months ended June 30, 2006, compared with $18 million for six months ended June 30, 2005.

Improved results for 2006 are driven primarily by addition of the Independence facility in February 2005. Independence contributed results of $19 million for the six months ended June 30, 2006, compared with $6 million for February through June 2005. Average on-peak prices for Zone A decreased from $60.13 per MWh in 2005 to $59.19 per MWh in 2006. Generated volumes decreased from 1.0 million MWh for the six months ended June 30, 2005 to 0.6 million MWh for the same period in 2006. Although generated volumes from our Independence facility decreased year over year, we received a benefit of approximately $10 million from realization of higher power prices in the first half of 2006, as we settled forward power sales. The increased results also related to merchant capacity payments. Operating expenses were also lower by $1 million, due to revisions to the terms of a long-term service agreement.

Results for our Roseton and Danskammer facilities increased from $12 million in 2005 to $19 million in 2006 primarily as a result of higher capacity revenue. Average on-peak prices for Zone G, the market served by these two facilities, increased from $74.09 per MWh in 2005 to $74.41 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 1.3 million MWh from the six months ended June 30, 2005 as compared to the six months ended June 30, 2006. Generated volumes at our Danskammer facility decreased by 0.2 million MWh for the six months ended June 30, 2005 compared to the six months ended June 30, 2006. Results from our Roseton and Danskammer facilities also increased by $10 million as a result of the opportunistic sale of emissions credits deemed to be short-term excess credits because of lower than expected run times. However, this increase was offset by net mark-to-market losses of $13 million for the six months ended June 30, 2006, related to financial transactions not designated as cash flow hedges. The six months ended June 30, 2005 results included mark-to-market losses of $3 million.

Depreciation expense for GEN-NE increased from $10 million to $12 million, as the result of adding the Independence facility in February 2005.

Power Generation South Segment. Operating loss for GEN-SO was $23 million for six months ended June 30, 2006, and the six months ended June 30, 2005. GEN-SO for the six months ended June 30, 2005, included general and administrative expenses of $6 million. Beginning in 2006, general and administrative expenses are reported in our Other segment. Please read Results of Operations Operating Income (Loss) Other for a consolidated discussion of general and administrative expenses.

Results from our ERCOT facility decreased by $5 million, from a loss of $2 million in 2005 to a loss of $7 million in 2006. Power prices increased by 5% from 2005 to 2006, offset by an 18% decrease in volumes. The decrease was offset further by the negative effect of higher gas prices on the steam contract at our CoGen Lyondell cogeneration facility in 2006. Included in the 2006 results are $4 million of mark-to-market gains, which relate to hedge ineffectiveness in the ERCOT region. This gain was offset by decreases in ancillary services revenue caused by a depressed ancillary services market in the ERCOT region during the second quarter of 2006.

Results from our other south assets increased from $3 million in the six months ended June 30, 2005 to $5 million in the same period in 2006, primarily as a result increased volumes in our peaking facilities.

Depreciation expense was $12 million for the six months ended June 30, 2006 and $10 million for the six months ended June 30, 2005. In addition, during the second quarter 2006, we recorded a $9 million impairment of our Rockingham facility, resulting from the pending sale. Please read Note 3 Dispositions, Contract Terminations and Discontinued Operations Dispositions and Contract Terminations Rockingham for further discussion. Additionally, our 2005 results include a $7 million charge associated with the write-off of an environmental project.

CRM. Operating income for the CRM segment was $6 million for the six months ended June 30, 2006, compared to operating loss of $207 million for the six months ended June 30, 2005. Our 2006 income was driven primarily by mark-to-market gains on our legacy emissions positions and the release of a disputed liability based on management s estimate of the likely outcome. This was offset by a $31 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 $170 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 $170 million charge upon completion of the acquisition. In addition, this segment s 2005 results reflect $46 million of fixed payments on our power tolling arrangements in excess of realized margins on power generated and sold.

Other. Other operating loss was $81 million for the six months ended June 30, 2006, compared to a loss of $321 million for the six months ended June 30, 2005. Results for the six months ended June 30, 2006 include approximately $71 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 six months ended June 30, 2005 included general and administrative expenses of $328 million.

Consolidated general and administrative expenses decreased from $345 million for the six months ended June 30, 2005 to $101 million for the six months ended June 30, 2006. General and administrative expenses for 2005 included a $240 million charge associated with settlement of our shareholder class action litigation and other legal settlement charges totaling $13 million, while 2006 included $32 million in additional legal reserves. Additionally, compensation and benefits costs and professional and legal fees were lower in 2006 compared to 2005.

Earnings from Unconsolidated Investments

The $2 million earnings reported from unconsolidated investments for the six months ended June 30, 2006 included the GEN-SO investment in Black Mountain. The $7 million earnings reported for the six months ended June 30, 2005 includes results from GEN-SO investments in both Black Mountain and West Coast Power.

Other Items, Net

Other items, net totaled $30 million of income for the six months ended June 30, 2006, compared to $9 million of income for the six months ended June 30, 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 and debt conversion costs totaled $452 million for the six months ended June 30, 2006, compared to $185 million for the six months ended June 30, 2005. The increase is primarily attributable to debt conversion costs and acceleration of financing costs resulting from our liability management program executed in the second quarter of 2006. Please read Note 7 Debt for further discussion.

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Income Tax Benefit

We reported an income tax benefit from continuing operations of $115 million for the six months ended June 30, 2006, compared to an income tax benefit from continuing operations of $215 million for the six months ended June 30, 2005. The 2006 effective tax rate was 36%, compared to 35% 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.

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

Six Months Ended June 30, 2006

	U.K. CRM	NGL (in millions)	Total
Operating income included in income from discontinued operations	$ (3)	$ 1	$ (2)
Other items, net included in income from discontinued operations	2		2
Income from discontinued operations before taxes			
Income tax benefit			1
Income from discontinued operations			$ 1

Six Months Ended June 30, 2005

	U.K. CRM	NGL (in millions)	Total
Operating income included in income from discontinued operations	$ (1)	$ 112	$ 111
Earnings from unconsolidated investments included in income from discontinued operations		4	4
Other items, net included in income from discontinued operations	6	(10)	(4)
Interest expense included in income from discontinued operations			(25)
Income from discontinued operations before taxes			86
Income tax benefit			80
Income from discontinued operations			$ 166

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 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 six months ended June 30, 2006, pre-tax income from discontinued operations of zero ($1 million after-tax) included $1 million in pre-tax income attributable to NGL and a loss of $1 million attributable to U.K. CRM associated with the settlement of an outstanding contract. During the six months ended June 30, 2005, pre-tax income from discontinued operations of $86 million ($166 million after-tax) included $81 million in pre-tax income attributable to NGL.

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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 $25 million during the six months ended June 30, 2006 and 2005, respectively.

Income Tax Benefit From Discontinued Operations. We recorded an income tax benefit from discontinued operations of $1 million during the six months ended June 30, 2006, compared to an income tax benefit from discontinued operations of $80 million during the six months ended June 30, 2005. The income tax benefit in 2005 includes a $112 million benefit associated with reducing a valuation allowance related to our capital loss carryforward, which primarily relates to our third quarter 2002 sale of NNG. We reduced the valuation allowance related to our capital loss carryforward as a result of capital gains expected to be recognized from our sale of DMSLP. For further information regarding the sale, please see Note 3 Dispositions, Contract Terminations and Discontinued Operations Discontinued Operations Natural Gas Liquids. The effective rates for the six months ended June 30, 2006 and 2005, adjusting for the reduction of the valuation allowance in 2005, are 100% and 37%, respectively. FIN No. 18, Accounting for Income Taxes in Interim Periods an interpretation of APB Opinion No. 28 proscribes a detailed methodology of allocating income taxes between continuing and discontinued operations. This methodology often results in an effective rate for discontinued operations significantly different from the statutory rate of 35%.

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 financial results will continue to reflect sensitivity to fuel and emissions commodity prices, market structure and prices for energy, ancillary services and capacity, transportation and transmission logistics, weather conditions and in-market asset availability (IMA). We continue to manage price risk through optimization of fuel procurement, commercializing our power length in the prompt one to three months and limiting longer term forward sales to opportunities to capture attractive market prices. To the extent we do not choose to forward sell energy from our generation fleet, changes 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 (i) power prices, (ii) IMA of our assets and (iii) fuel availability and prices. A significant power sales agreement with AmerenIP will be expiring at the end of 2006. We expect this expiration to positively impact our 2007 and forward earnings as the sales price we receive under the terms of the AmerenIP contract are below the current market price for power for 2007 forward. Power generation capacity from our Midwest generating assets currently committed to meeting our obligations under that contract will then be able to access other market opportunities. Although we expect power prices to continue to remain high in the Midwest for the remainder of 2006, we will not be able to fully realize these prices as a result of the options held by AmerenIP in our fixed price power purchase agreement with them.

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. Depending on these decisions, expiration of this contract may result in increased exposure to market price volatility and in a potentially stronger price environment 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 a resource procurement auction as the process by which the major Illinois utilities will procure power beginning in 2007. There continue to be challenges to the auction process. 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. Numerous parties have appealed various aspects of the ICC Orders approving the auctions to the state intermediate appellate courts. More recently, the Illinois Attorney General has also filed for direct review by the state Supreme Court and a stay of the ICC Orders pending that review, which was denied. Please read Note 11 Regulatory Issues Illinois Resource Procurement Auction for further details. Given these uncertainties, the effect of the final process that will be used in Illinois cannot be predicted at this time.

Our IMA will also impact GEN-MW s results. We use IMA to monitor steam fleet performance over time. This measure quantifies the percentage of generation for each unit that was available when market prices were favorable for participation. Through our focus on safe, efficient operations, we seek to maximize our IMA and, as a result, our revenue generating opportunities. The IMA for our steam-driven fleet through June 2006 was approximately 87.5%, compared to 90.2% for the comparable period of 2005. A small increase in unscheduled outages designed to ensure compliance with the 2005 Consent Decree reduced run times, and was the primary reason for the decline in performance. We attempt to schedule maintenance and repair work to minimize downtime during peak demand periods but only to the extent doing so does not compromise a safe working environment for our employees and contractors.

In 2005, DMG entered into a comprehensive, Midwest system-wide settlement with the USEPA and other parties, resolving the environmental litigation related to our Baldwin Energy Complex in Illinois. The settlement involves substantial emission reductions from our Illinois coal-fired power plants and the completion of several supplemental environmental projects in the Midwest. Through June 30, 2006, DMG had achieved all of the scheduled emission reductions and was developing plans to install additional emission control equipment to meet future, more stringent emission limits. DMG recently received a construction permit for the mercury control project at the Vermilion Power Station that is scheduled for operation by June 30, 2007. Our estimated costs associated with the Consent Decree projects, which we expect to occur through 2013, have increased from a previously reported amount of $611 million to an estimated $674 million. Factors contributing to this growth are increased costs associated with the Vermilion Mercury Control Project and the anticipated cost of adding additional particulate control equipment at the Hennepin Station. Another major component of the increase is large commodity cost-escalations for raw materials (steel, cement and copper) required for the scrubbers and baghouses. These supply-side market pressures will continue to subject the final cost of Consent Decree compliance to significant volatility.

Operation of our Midwest generation facilities is, in part, dependent on our ability to procure and deliver coal from the Powder River Basin in Wyoming. Over the last six to eight quarters, power generators across the U.S. 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 beginning in the third quarter 2004, becoming more pronounced since May 2005, as a result of increased track maintenance programs, weather delays and train derailments. To decrease our risk of delivery-related disruptions, we have coordinated with our rail-service provider to deploy or re-deploy existing rail assets and coal supplies in an opportunistic fashion to provide coal deliveries to our highest margin plants to allow full economic dispatch during peak demand.

Through 2010, 96% of our coal requirements are contracted. Additionally, 97% of our coal requirements for 2006 and more than half of our coal requirements through 2008 are contracted at a fixed price. Our longer term results are sensitive to changes in coal prices to the extent that our current fixed price arrangements roll off or are adjusted through contract re-openers or related provisions.

During 2005, our results reflected increased demand for capacity-related products from our peaking 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 our experience through the date of this filing, we expect our peaking fleet will experience comparable dispatch opportunities in summer 2006 as were available in the summer of 2005. This will be largely subject to market demand and will therefore be heavily impacted by weather and system reliability.

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. As a result, we expect year-to-year decreased runtime for our

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intermediate facilities in the second half of 2006, particularly at our Roseton facility. In the Northeast, our Danskammer 3 facility has a major planned outage in the fall to address routine boiler work and extensive generator work. The Independence facility has several small outages planned to address routine inspections and repairs.

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 read Note 10 Commitments and Contingencies Roseton State Pollutant Discharge Elimination System Permit and Note 10 Commitments and Contingencies 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. Incremental annual operating income associated with this contract is expected to range between $40 million to $55 million. The primary drivers of this improvement are the adjustment to the price of steam supplied to Lyondell Chemical and our ability to optimize power and steam generation for the entire Lyondell Chemical facility to capture maximum market potential from CoGen Lyondell.

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 the majority of the portfolio capacity committed in the near term, and a 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 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 includes 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:

	Six Months Ended June 30, 2006	2005
	(in millions)	
Operating cash flows from our generation businesses	$ 271	$ 194
Operating cash flows from our customer risk management business	(392)	41
Operating cash flows from our natural gas liquids business		178
Other operating cash flows	(247)	(422)
Net cash used in operating activities	$ (368)	$ (9)

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Operating Cash Flow. Our cash flow used in operations totaled $368 million for the six months ended June 30, 2006. During the six months ended June 30, 2006, our power generation business provided positive cash flow from operations of $271 million primarily due to positive earnings for the period. Our customer risk management business used approximately $392 million in cash primarily due to a $370 million termination payment on our Sterlington tolling contract. 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 $247 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 $9 million for the six months ended June 30, 2005. During the period, our GEN, NGL and CRM segments provided positive cash flow from operations. GEN provided cash flow from operations of $194 million, and NGL provided cash flow from operations of $178 million primarily due to positive earnings for the period as well as the return of cash collateral. Our CRM segment provided cash flow of approximately $41 million primarily due to the return of cash collateral, offset by fixed payments associated with power tolling arrangements and our final payment of $26 million related to our exit from certain gas transportation contracts. Other and Eliminations includes a use of approximately $422 million in cash primarily due to our payment of $175 million in May 2005 in connection with the settlement of the shareholder class action litigation, interest payments to service debt and general and administrative expenses.

Capital Expenditures and Investing Activities. Cash provided by investing activities during the six months ended June 30, 2006 totaled $271 million. Capital spending of $59 million was primarily comprised of $36 million, $7 million, and $12 million in the GEN-MW, GEN-NE, and GEN-SO segments, respectively. The capital spending for the GEN-MW segment primarily related to maintenance and environmental 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.

Net proceeds from the sale and acquisition of unconsolidated investments, net of cash acquired totaled $165 million. This included net cash proceeds of $205 million from 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. This was partially offset by $40 million, net of cash acquired, associated with our acquisition of NRG s 50% ownership interest in Rocky Road. Please read Note 2 Acquisition for more information.

The decrease in restricted cash of $162 million related primarily to the return of our $335 million deposit associated with our former cash collateralized facility and a $27 million decrease in the Independence restricted cash balance, offset by a $200 million deposit associated with our cash collateralized facility.

Cash used in investing activities during the six months ended June 30, 2005 totaled $210 million. Capital spending of $93 million was primarily comprised of $57 million, $7 million, $1 million and $23 million in the GEN-MW, GEN-NE, GEN-SO and NGL segments, respectively. The capital spending for the generation business segments primarily related to maintenance capital projects, as well as $10 million in development capital associated with the completion of the Havana PRB conversion in GEN-MW. 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 six months ended June 30, 2006 totaled $1,094 million. Repayments of long-term debt totaled $1,683 million for the six months ended June 30, 2006 and consisted of the following payments:

- $900 million in aggregate principal amount on our 10.125% Second Priority Senior Secured Notes due 2013;
- $614 million in aggregate principal amount on our 9.875% Second Priority Senior Secured Notes due 2010;
- $151 million in aggregate principal amount on our DHI Second Priority Senior Secured Floating Rate Notes due 2008; and
- $18 million in aggregate principal amount on our 8.50% secured bonds due 2007.

In addition to the above repayments, we redeemed all of the outstanding shares of our Series C Preferred for $400 million.

Debt conversion costs of $247 million consisted of the following payments:

- $202 million to redeem of the Second Priority Senior Secured Notes mentioned above, including approximately $3 million of transaction costs;
- $44 million aggregate premium to induce conversion of our $225 million 4.75% Convertible Subordinated Debentures due 2023; and
- $1 million in transaction costs associated with the redemption of our Series C Preferred.

The repayments were partially offset by $1,071 million of proceeds from the following sources, net of approximately $29 million of debt issuance costs:

- $750 million aggregate principal amount from a private offering of our 8.375% Senior Unsecured Notes due 2016;
- $200 million, LIBOR + 1.75% letter of credit facility due 2012; and
- $150 million, LIBOR + 1.75% term loan due 2012.

Proceeds from the issuance of common stock consisted primarily of approximately $178 million in proceeds from a common stock offering of 40.25 million shares of our Class A common stock at $4.60 per share, net of underwriting fees. Dividend payments totaling $17 million were also made on our Series C Preferred prior to its redemption.

Cash used in financing activities during the six months ended June 30, 2005 totaled $51 million. Repayments of long-term debt totaled $38 million for the six months ended June 30, 2005 and consisted of the following: (i) payments of $18 million on a maturing series of DHI senior notes; (ii) payments of $17 million on the Independence Senior Notes due 2007 and (iii) payments of $3 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 Preferred.

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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 Six Months Ended June 30, 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	12
Cash received related to risk-management contracts settled in the period, net	(21)
Changes in fair value as a result of a change in valuation technique (1)	
Non-cash adjustments and other (2)	22
Fair value of portfolio at June 30, 2006	$ (99)

(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 $99 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 June 30, 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 (in millions)	2009	2010	Thereafter
June 30, 2006(2)	$ (77)	$ (3)	$ (72)	$ (6)	$	$	$ 4
December 31, 2005 (2)	(84)	(5)	(65)	(19)	2		3
Increase	$ 7	$ 2	$ (7)	$ 13	$ (2)	$	$ 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 June 30, 2006 of $99 million on the unaudited condensed consolidated balance sheets include the $77 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 June 30, 2006 and December 31, 2005 were derived solely from market quotations.
(3) Amounts represent July 1 to December 31, 2006 values in the June 30, 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

	Six Months Ended June 30, 2006	Six Months Ended December 31, 2006	Total 2006	2007	2008	2009	2010	Thereafter
				(in millions)				
June 30, 2006(1)	$ (3)	$ (3)	$ (6)	$ (74)	$ (6)	$	$	$ 6
December 31, 2005			1	(64)	(21)	2		4
Increase			$ (7)	$ (10)	$ 15	$ (2)	$	$ 2

(1) The cash flow values for 2006 reflect realized cash flows for the six months ended June 30, 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 and generation volumes;
- our focus on safety and our ability to efficiently operate our assets so as to maximize our revenue-generating opportunities;
- strategies to capture opportunities presented by rising commodity prices and strategies to manage our exposure to energy price volatility while reducing our long-term hedging activities;
- plans to achieve fuel-related, general and administrative, and other targeted cost savings;
- beliefs and assumptions relating to our liquidity position;

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, including strategies to deploy coal supplies;

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 weaknesses existing in our accounting for income taxes and our risk management assets and liabilities;

expectations and estimates regarding the consent decree and the associated costs;

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/A.

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 market risks, including foreign currency exchange rate risk. Following is a discussion of the more material of these risks and our relative exposures as of June 30, 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

	June 30, 2006	December 31, 2005
	(in millions)	
One Day VaR 95% Confidence Level	$ 3	$ 5
One Day VaR 99% Confidence Level	$ 4	$ 6
Average VaR for the Year-to-Date Period 95% Confidence Level	$ 3	$ 7

Credit Risk. The following table represents our credit exposure at June 30, 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 (in millions)	Total
Type of Business:			
Financial Institutions	$ 79	$	$ 79
Commercial/Industrial/End Users	20	2	22
Utility and Power Generators	12	7	19
Oil and Gas Producers	6		6
Total	$ 117	$ 9	$ 126

Of the $9 million in credit exposure to non-investment grade counterparties, 95% is collateralized or subject to other credit exposure protection.

Interest Rate Risk. We are exposed to fluctuating interest rates related to variable rate financial obligations. As of June 30, 2006, our fixed rate debt instruments as a percentage of total debt instruments was approximately 79%. Based on sensitivity analysis of the variable rate financial obligations in our debt portfolio as of June 30, 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 June 30, 2007 would either decrease or increase income before taxes by approximately $10 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 June 30, 2006 and December 31, 2005, respectively:

Absolute Notional Contract Amounts

	June 30, 2006	December 31, 2005
Natural Gas (Trillion Cubic Feet)	0.377	0.374
Electricity (Million Megawatt Hours) (1)	64.264	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
Interest Rate Risk-Management Contract (In Millions of U.S. Dollars)	$ 306	$ 306
Fixed Interest Rate Paid (Percent)	5.29	5.29
Interest Rate Risk-Management Contract (In Millions of U.S. Dollars)	$ 281	$ 281
Fixed Interest Rate Received (Percent)	5.23	5.23

(1) This amount includes notional volumes related to additional Financial Transmission Rights (FTRs) that we acquired in various ISOs during 2006.

(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 second 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 June 30, 2006, as a result of the material weaknesses identified and 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 June 30, 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 June 30, 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 June 30, 2006, we concluded that this control deficiency constitutes a material weakness.

Material Weakness Related to Risk Management Assets and Liabilities. As of June 30, 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 first quarter 2006 interim condensed consolidated financial statements prior to being reported in our Quarterly Report on Form 10-Q for the interim period ended March 31, 2006. 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 June 30, 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 the second quarter of 2006, we began the process of implementing 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; (iii) further formalizing and documenting the procedures around the preparation and review of the tax provision and tax accounts; (iv) enhancing staff competencies in the Tax Department through training initiatives and staff additions; (v) formalizing communication channels between the Tax and Accounting Departments; and (vi) simplifying the data entry process surrounding the automated tax provision calculation. We also engaged an independent consulting firm, who has assessed and is now providing recommendations to strengthen our 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, during the second quarter 2006, we implemented the following steps around our risk management asset and liability valuation process: (i) automated a process step that was previously performed manually; (ii) further formalized and documented the procedures around the end-of-day valuation process; (iii) expanded the review and validation process with respect to pricing data; (iv) performed a review of all pricing data to eliminate redundant or unnecessary data; and (v) implemented a new monthly process to identify pricing data related to active positions. In addition, we have engaged an independent third party to review, evaluate and test our processes, procedures and controls related to the calculation and analysis of pricing data. We expect this review to be completed during the third quarter of 2006.

We believe we are taking the steps necessary to remediate this material weakness related to the accuracy of our risk management asset and liability balances. However, the controls have not been in place for an adequate period of time to test and conclude that they are operating effectively. 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.

Changes in Internal Control 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 and page 56 of our first quarter 2006 Form 10-Q 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 and first quarter 2006 Form 10-Q.

We have reported two material weaknesses in our internal control over financial reporting, one of which caused a restatement, and both of which, if not remedied, could continue to adversely affect our internal controls and financial reporting.

In connection with our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, our 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.

Likewise, in connection with our management s assessment of the effectiveness of our internal control over financial reporting as of June 30, 2006, our management concluded that, as of June 30, 2006, we did not maintain effective internal control over our financial reporting due to the same material weakness in our processes, procedures and controls related to the preparation, analysis and recording of the income tax provision. Also in connection with our management s assessment as of June 30, 2006, our management concluded that, as of June 30, 2006, 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 calculation and analysis of our risk management asset and liability balances. 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 Annual Report on Form 10-K, as amended, for the fiscal year ended December 31, 2004 that we did not maintain effective internal control over our financial reporting as of December 31, 2004 due to a material weakness in our processes, procedures and controls related to the preparation, analysis and recording of the income tax provision. During 2005, actions were taken to remediate this material weakness. 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 processes and 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 our consolidated financial statements for the year ended December 31, 2005, as reported in Amendment No. 1 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2005. 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 our annual or interim consolidated financial statements that would not be prevented or detected.

The material weakness related to the calculation and analysis of our risk management asset and liability balances resulted in an adjustment to our condensed consolidated financial statements as of and for the three months

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ended March 31, 2006 prior to being reported in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006. 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 our annual or interim consolidated financial statements that would not be prevented or detected.

We believe we are taking the steps necessary to remediate the 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. We also believe we are taking the steps necessary to remediate the material weakness related to the accuracy of our risk management asset and liability balances. However, the controls have not been in place for an adequate period of time to test and conclude that they are operating effectively. 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; however, we cannot be assured that these processes, procedures and controls will result in remediation. Failure to remediate these material weaknesses, or the identification of additional material weaknesses, could result in materially inaccurate financial reports and negatively impact the market s view of our control environment and, potentially, our stock price.

Item 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Our 2006 annual meeting of shareholders was held on May 17, 2006. The purpose of the annual meeting was to consider and vote upon the following proposals:

1. To elect eight Class A common stock directors and two Class B common stock directors to serve until the 2007 annual meeting of shareholders;

2. To act upon a proposal to amend our articles of incorporation to remove the provision specifying a minimum and maximum number of directors;

3. To act upon a proposal to amend and restate our articles of incorporation to eliminate unnecessary and outdated provisions; and

4. To act upon a proposal to ratify the appointment of PricewaterhouseCoopers LLP as our independent auditors for the fiscal year ending December 31, 2006.

Our current Board of Directors is comprised of ten members. At the annual meeting, each of the following individuals was elected to serve as one of our directors: David W. Biegler, Thomas D. Clark, Jr., Victor J. Grijalva, Patricia A. Hammick, George L. Mazanec, Robert C. Oelkers, Rebecca Roberts, Howard B. Sheppard, William L. Trubeck and Bruce A. Williamson. The votes cast for each nominee and the votes withheld were as follows:

Class A Directors

		FOR	WITHHELD
1.	David W. Biegler	255,561,653	6,386,116
2.	Thomas D. Clark, Jr.	255,367,446	6,571,620
3.	Victor J. Grijalva	255,634,599	6,304,451
4.	Patricia A. Hammick	256,981,748	5,008,124
5.	George L. Mazanec	253,643,553	8,295,503
6.	Robert C. Oelkers	253,664,772	8,276,773
7.	William L. Trubeck	253,545,092	8,394,639
8.	Bruce A. Williamson	255,406,866	6,555,444

Class B Directors

		FOR	WITHHELD
1.	Rebecca Roberts	96,891,014	0
2.	Howard B. Sheppard	96,891,014	0

The following votes were cast with respect to the proposal to amend our articles of incorporation to remove the provision specifying a minimum and maximum number of directors. There were 105,426,805 broker non-votes. This proposal failed to receive the affirmative votes of two-thirds of the outstanding shares of Class A common stock required under Illinois law. Thus, the size of our Board of Directors has been set at 12 , the minimum allowable under out articles of incorporation, and a search has commenced for qualified candidates to fill the two board vacancies at our before the 2007 annual meeting of shareholders.

Class A Common Stock

FOR	AGAINST	ABSTAIN
105,098,656	49,139,043	2,274,271

Class B Common Stock

FOR	AGAINST	ABSTAIN
96,891,014	0	0

The following votes were cast with respect to the proposal to amend and restate our articles of incorporation to eliminate unnecessary and outdated provisions, which passed. There were no broker non-votes.

FOR	AGAINST	ABSTAIN
354,262,484	2,281,254	2,286,051

The following votes were cast with respect to the proposal to ratify the selection of PricewaterhouseCoopers LLP as our independent auditors for the fiscal year ended December 31, 2006, which passed. There were no broker non-votes.

FOR	AGAINST	ABSTAIN
351,743,657	4,797,167	2,288,963

Item 6 EXHIBITS

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

Exhibit Number	Description
**1.1	Underwriting Agreement, dated as of May 23, 2006, by and among Dynegy Inc., J.P. Morgan Securities Inc. and Lehman Brothers Inc.
**3.1	Amended and Restated Articles of Incorporation of Dynegy Inc.
3.2	Amendment No. 1, effective as of May 19, 2006, to the Amended and Restated Bylaws of Dynegy Inc., dated as of November 16, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 22, 2006, File No. 1-15659).

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4.1	Supplemental Indenture, dated as of May 16, 2006, by and among Dynegy Inc., Dynegy Holdings Inc., and Wilmington Trust Company, as trustee, supplementing the Indenture, dated as of August 11, 2003, pursuant to which the 4.75% Convertible Subordinated Debentures due 2023 of Dynegy Inc. were issued (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 16, 2006, File No. 1-15659).
4.2	Second Amended and Restated Shareholder Agreement, dated as of May 26, 2006, by and between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 1, 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 March 29, 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).
4.5	Registration Rights Agreement, effective as of July 21, 2006, by and among Dynegy Holdings Inc. RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 2006, File No. 1-15659).
10.1	Purchase Agreement, dated as of May 21, 2006, by and between Dynegy Inc. and Rockingham Power, L.L.C., as sellers, and Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC, as purchaser (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on May 25, 2006, File No. 1-15659).
10.2	Preferred Stock Redemption Agreement, dated as of May 22, 2006, by and between Dynegy Inc. and Chevron U.S.A. Inc. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on May 25, 2006, File No. 1-15659).
10.3	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).
10.4	Amendment No. 1, dated as of May 26, 2006, to the 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 the various other parties thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on June 1, 2006, File No. 1-15659).

**10.5	Amendment No. 2, dated as of July 11, 2006, to the 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 the various other parties thereto.
10.6	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 (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q of Dynegy Inc. for the quarterly period ended March 31, 2006 filed on May 10, 2006, File No. 1-15659).
10.7	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) (incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q of Dynegy Inc. for the quarterly period ended March 31, 2006 filed on May 10, 2006, File No. 1-15659).
10.8	Exchange Agreement, dated as of July 21, 2006, by and among Dynegy Holdings Inc., RCP Debt, LLC and RCMF Debt, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Dynegy Inc. filed on July 24, 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 Securities 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: August 9, 2006	By:	/s/ Holli C. Nichols **Holli C. Nichols**
		Executive Vice President and Chief Financial Officer
		(Duly Authorized Officer and Principal Financial Officer)