UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

F O R M 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, 2009**

or

[ ] 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: **1-11234**

KINDER MORGAN ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**76-0380342**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

500 Dallas Street, Suite 1000, Houston, Texas 77002
(Address of principal executive offices)(zip code)
Registrant's telephone number, including area code: **713-369-9000**

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 has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Securities Exchange Act of 1934. Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes [ ] No [X]

The Registrant had 197,913,626 common units outstanding as of July 31, 2009.

KINDER MORGAN ENERGY PARTNERS, L.P.
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In Millions Except Per Unit Amounts)
(Unaudited)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenues				
Natural gas sales	$ 716.9	$ 2,464.7	$ 1,605.6	$ 4,185.9
Services	652.1	677.8	1,313.5	1,353.5
Product sales and other	276.3	353.2	512.7	676.6
Total Revenues	1,645.3	3,495.7	3,431.8	6,216.0
Operating Costs, Expenses and Other				
Gas purchases and other costs of sales	709.6	2,494.2	1,575.3	4,226.3
Operations and maintenance	267.3	308.2	517.3	594.6
Depreciation, depletion and amortization	203.1	165.6	413.3	323.7
General and administrative	72.6	72.8	155.1	149.6
Taxes, other than income taxes	23.4	51.0	62.4	99.0
Other expense (income)	(2.7)	(2.3)	(3.6)	(2.8)
Total Operating Costs, Expenses and Other	1,273.3	3,089.5	2,719.8	5,390.4
Operating Income	372.0	406.2	712.0	825.6
Other Income (Expense)				
Earnings from equity investments	41.9	46.2	80.1	83.9
Amortization of excess cost of equity investments	(1.5)	(1.5)	(2.9)	(2.9)
Interest, net	(96.0)	(98.8)	(193.2)	(195.5)
Other, net	20.2	23.3	30.9	26.2
Total Other Income (Expense)	(35.4)	(30.8)	(85.1)	(88.3)
Income from Continuing Operations Before Income Taxes	336.6	375.4	626.9	737.3
Income Taxes	(8.0)	(9.9)	(31.5)	(21.6)
Income from Continuing Operations	328.6	365.5	595.4	715.7
Discontinued Operations (Note 8):				
Adjustment to gain on disposal of North System	—	0.8	—	1.3
Income from Discontinued Operations	—	0.8	—	1.3
Net Income	328.6	366.3	595.4	717.0
Net Income attributable to Noncontrolling Interests	(4.8)	(4.1)	(7.7)	(8.1)
Net Income attributable to Kinder Morgan Energy Partners, L.P.	$ 323.8	$ 362.2	$ 587.7	$ 708.9
Calculation of Limited Partners' interest in Net Income Attributable to Kinder Morgan Energy Partners, L.P.:				
Income from Continuing Operations	$ 323.8	$ 361.4	$ 587.7	$ 707.6
Less: General Partner's interest	(232.8)	(195.9)	(456.5)	(383.3)
Limited Partners' interest	91.0	165.5	131.2	324.3
Add: Limited Partners' interest in Discontinued Operations	—	0.8	—	1.3
Limited Partners' interest in Net Income	$ 91.0	$ 166.3	$ 131.2	$ 325.6
Limited Partners' Net Income per Unit:				
Income from Continuing Operations	$ 0.33	$ 0.64	$ 0.48	$ 1.28
Income from Discontinued Operations	—	0.01	—	—
Net Income	$ 0.33	$ 0.65	$ 0.48	$ 1.28
Weighted average number of units used in computation of Limited Partners' Net Income per unit	277.5	256.7	273.5	253.9
Per unit cash distribution declared	$ 1.05	$ 0.99	$ 2.10	$ 1.95

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Millions)
(Unaudited)

	June 30, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 102.5	$ 62.5
Restricted deposits	21.8	—
Accounts, notes and interest receivable, net	735.2	987.9
Inventories	55.6	44.2
Gas imbalances	12.5	14.1
Gas in underground storage	50.0	—
Fair value of derivative contracts	44.8	115.3
Other current assets	38.0	20.4
Total Current Assets	1,060.4	1,244.4
Property, plant and equipment, net	13,667.1	13,241.4
Investments	1,730.0	954.3
Notes receivable	181.5	178.1
Goodwill	1,079.2	1,058.9
Other intangibles, net	202.9	205.8
Fair value of derivative contracts	345.3	796.0
Deferred charges and other assets	188.3	206.9
Total Assets	$ 18,454.7	$ 17,885.8
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Current portion of debt	$ 145.4	$ 288.7
Cash book overdrafts	21.2	42.8
Accounts payable	476.5	855.6
Accrued interest	193.5	172.3
Accrued taxes	56.0	51.9
Deferred revenues	50.6	41.1
Gas imbalances	25.0	12.4
Fair value of derivative contracts	228.6	129.5
Accrued other current liabilities	139.2	187.8
Total Current Liabilities	1,336.0	1,782.1
Long-Term Liabilities and Deferred Credits		
Long-term debt		
Outstanding	9,254.4	8,274.9
Value of interest rate swaps	470.6	951.3
Total Long-term debt	9,725.0	9,226.2
Deferred revenues	11.8	12.9
Deferred income taxes	187.2	178.0
Asset retirement obligations	83.0	74.0
Fair value of derivative contracts	396.1	92.2
Other long-term liabilities and deferred credits	373.6	404.1
Total Long-Term Liabilities and Deferred Credits	10,776.7	9,987.4
Total Liabilities	12,112.7	11,769.5
Commitments and Contingencies (Notes 4 and 10)		
Partners' Capital		
Common Units	3,849.5	3,458.9
Class B Units	86.0	94.0
i-Units	2,622.8	2,577.1
General Partner	214.5	203.3
Accumulated other comprehensive loss	(505.1)	(287.7)
Total Kinder Morgan Energy Partners, L.P. Partners' Capital	6,267.7	6,045.6
Noncontrolling interests	74.3	70.7
Total Partners' Capital	6,342.0	6,116.3
Total Liabilities and Partners' Capital	$ 18,454.7	$ 17,885.8

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Increase/(Decrease) in Cash and Cash Equivalents in Millions)
(Unaudited)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cash Flows From Operating Activities		
Net Income	$ 595.4	$ 717.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	413.3	323.7
Amortization of excess cost of equity investments	2.9	2.9
Income from the allowance for equity funds used during construction	(20.3)	—
Income from the sale of property, plant and equipment and investments	(3.6)	(17.1)
Earnings from equity investments	(80.1)	(83.9)
Distributions from equity investments	100.3	64.3
Proceeds from termination of interest rate swap agreements	144.4	—
Changes in components of working capital:		
Accounts receivable	184.5	(457.4)
Other current assets	(68.2)	(34.8)
Inventories	(11.2)	(4.7)
Accounts payable	(278.4)	389.3
Accrued interest	21.2	17.8
Accrued liabilities	(24.3)	89.9
Accrued taxes	3.4	(7.7)
Rate reparations, refunds and other litigation reserve adjustments	(15.5)	(23.3)
Other, net	(27.0)	(1.3)
Net Cash Provided by Operating Activities	936.8	974.7
Cash Flows From Investing Activities		
Acquisitions of assets	(18.5)	(4.2)
Repayments for Trans Mountain Pipeline	—	23.4
Repayments from customers	109.6	—
Capital expenditures	(796.6)	(1,262.6)
Sale of property, plant and equipment, and other net assets net of removal costs	(4.7)	47.9
Investments in margin deposits	(24.9)	(207.1)
Contributions to equity investments	(802.8)	(338.7)
Distributions from equity investments	—	89.1
Natural gas stored underground and natural gas liquids line-fill	—	(2.7)
Net Cash Used in Investing Activities	(1,537.9)	(1,654.9)
Cash Flows From Financing Activities		
Issuance of debt	3,237.1	4,769.3
Payment of debt	(2,392.8)	(3,770.6)
Repayments from related party	2.5	1.5
Debt issue costs	(5.6)	(10.3)
Increase (Decrease) in cash book overdrafts	(21.6)	27.1
Proceeds from issuance of common units	669.5	384.3
Contributions from noncontrolling interests	8.6	5.9
Distributions to partners and noncontrolling interests:		
Common units	(391.4)	(326.6)
Class B units	(11.2)	(10.0)
General Partner	(445.5)	(360.9)
Noncontrolling interests	(10.8)	(8.9)
Other, net	(0.2)	0.2
Net Cash Provided by Financing Activities	638.6	701.0
Effect of exchange rate changes on cash and cash equivalents	2.5	(1.0)
Increase in Cash and Cash Equivalents	40.0	19.8
Cash and Cash Equivalents, beginning of period	62.5	58.9
Cash and Cash Equivalents, end of period	$ 102.5	$ 78.7
Noncash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	$ 3.7	$ 2.3
Assets acquired by the issuance of units	5.0	—
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	205.5	173.9
Cash paid during the period for income taxes	8.2	33.4

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. General

Organization

Kinder Morgan Energy Partners, L.P. is a leading pipeline transportation and energy storage company in North America, and unless the context requires otherwise, references to "we," "us," "our," "KMP" or the "Partnership" are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries. We own an interest in or operate more than 28,000 miles of pipelines and 170 terminals, and presently conduct our business through five reportable business segments (described further in Note 8). Our pipelines transport natural gas, refined petroleum products, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals and handle bulk materials like coal and petroleum coke. We are also the leading provider of carbon dioxide for enhanced oil recovery projects in North America. Our general partner is owned by Kinder Morgan, Inc. (formerly Knight Inc.), a private company discussed following.

Kinder Morgan, Inc., Kinder Morgan G.P., Inc. and Kinder Morgan Management, LLC

Kinder Morgan, Inc., referred to as "KMI" in this report, is owned by investors led by Richard D. Kinder, Chairman and Chief Executive Officer of Kinder Morgan G.P., Inc. (our general partner), and Kinder Morgan Management, LLC (our general partner's delegate). KMI was for a period known as "Knight Inc.," the surviving legal entity from the May 30, 2007 going-private transaction of Kinder Morgan, Inc., as discussed in our Annual Report on Form 10-K for the year ended December 31, 2008, referred to in this report as our 2008 Form 10-K. On July 15, 2009, Knight Inc. changed its name back to Kinder Morgan, Inc.

KMI indirectly owns all the common stock of our general partner. In July 2007, our general partner issued and sold 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us or two of our subsidiaries, SFPP, L.P. and Calnev Pipe Line LLC.

Kinder Morgan Management, LLC, referred to as "KMR" in this report, is a Delaware limited liability company. Our general partner owns all of KMR's voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. More information on these entities and the delegation of control agreement is contained in our 2008 Form 10-K.

Basis of Presentation

We have prepared our accompanying unaudited consolidated financial statements under the rules and regulations of the Securities and Exchange Commission. Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America.

We believe, however, that our disclosures are adequate to make the information presented not misleading. Our consolidated financial statements reflect normal adjustments, and also recurring adjustments that are, in the opinion of our management, necessary for a fair presentation of our financial results for the interim periods. You should read these consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our 2008 Form 10-K.

Our consolidated financial statements include our accounts and those of our operating partnerships and their majority-owned and controlled subsidiaries. Our accounting records are maintained in United States dollars, and all references to dollars are United States dollars, except where stated otherwise. Canadian dollars are designated as

C$. All significant intercompany items have been eliminated in consolidation, and certain amounts from prior periods have been reclassified to conform to the current presentation. We evaluated subsequent events—events or transactions that occurred after June 30, 2009 but before our accompanying consolidated financial statements were issued—through July 31, 2009, the date we issued our accompanying consolidated financial statements.

Pursuant to the transition provisions of Statement of Financial Accounting Standards No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51," we adopted the Statement on January 1, 2009 via retrospective application of the presentation and disclosure requirements. For more information on this Statement, see Note 12. On June 12, 2009, we filed a Current Report on Form 8-K to update certain sections of our 2008 Form 10-K solely to reflect the retrospective presentation and disclosure requirements of SFAS No. 160. The Form 8-K included Item 6 "Selected Financial Data," Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8 "Financial Statements and Supplementary Data," and no other items from our 2008 Form 10-K were adjusted or otherwise revised. The Form 8-K did not reflect any subsequent information or events other than the adoption of presentation and disclosure requirements of SFAS No. 160. Accordingly, whenever we refer in this report to disclosure contained in our 2008 Form 10-K, such references also apply to the relevant Form 10-K items included in the Form 8-K.

In addition, effective January 1, 2006, in accordance with the provisions of the Financial Accounting Standards Board's Emerging Issues Task Force Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights," our financial statements are consolidated into the consolidated financial statements of KMI. Notwithstanding the consolidation of our financial statements into the consolidated financial statements of KMI, except for the related party transactions described in Note 9 "Related Party Transactions—KMI—Asset Contributions," KMI is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or KMI's financial statements is a legal determination based on the entity that incurs the liability. Furthermore, the determination of responsibility for payment among entities in our consolidated group of subsidiaries was not impacted by the adoption of EITF 04-5.

Limited Partners' Net Income Per Unit

We compute Limited Partners' Net Income per Unit by dividing our limited partners' interest in net income by the weighted average number of units outstanding during the period. See Note 12 for further information regarding recent accounting pronouncements relating to earnings per unit.

2. Acquisitions and Joint Ventures

Acquisitions

Effective April 23, 2009, we acquired certain assets from Megafleet Towing Co., Inc. for an aggregate consideration of approximately $21.7 million. Our consideration included $18.0 million in cash and an obligation to pay additional cash consideration on April 23, 2014 (five years from the acquisition date) contingent upon the purchased assets providing us an agreed-upon amount of earnings during the five year period. The contingent consideration had a fair value of $3.7 million as of the acquisition date, and there has been no change in the fair value during the post-acquisition period ended June 30, 2009.

The acquired assets primarily consist of nine marine vessels that provide towing and harbor boat services along the Gulf coast, the intracoastal waterway, and the Houston Ship Channel. The acquisition complements and expands our existing Gulf Coast and Texas petroleum coke terminal operations, and all of the acquired assets are included in our Terminals business segment. We allocated $7.1 million of our combined purchase price to "Property, Plant and Equipment, net," $4.0 million to "Other Intangibles net," and the remaining $10.6 million to "Goodwill." We believe the primary item that generated the goodwill is the value of the synergies created between the acquired assets and our pre-existing terminal assets (resulting from the increase in services now offered by our Texas petroleum coke operations), and we expect that approximately $5.0 million of goodwill will be deductible for tax purposes.

Joint Ventures

In the second quarter of 2009, we made capital contributions of $222 million to Midcontinent Express Pipeline LLC and $382.5 million to West2East Pipeline LLC (the sole owner of Rockies Express Pipeline LLC) to partially fund construction costs for the Midcontinent Express and the Rockies Express natural gas pipeline systems, respectively. We also contributed $22.2 million to Fayetteville Express Pipeline LLC in the second quarter of 2009 to partially fund certain pre-construction pipeline costs for the Fayetteville Express Pipeline. We own a 50% equity interest in Midcontinent Express Pipeline LLC, a 51% equity interest in West2East Pipeline LLC (and Rockies Express Pipeline LLC), and a 50% equity interest in Fayetteville Express Pipeline LLC.

For the first six months of 2009, we contributed $333 million, $433.5 million, and $31.2 million, respectively, to the Midcontinent Express, Rockies Express, and Fayetteville Express joint venture pipeline projects. We included all of these cash contributions as increases to "Investments" in our accompanying consolidated balance sheet as of June 30, 2009, and as "Contributions to equity investments" in our accompanying consolidated statement of cash flows for the six months ended June 30, 2009.

Pro Forma Information

Pro forma consolidated income statement information that gives effect to all of the acquisitions we have made and all of the joint ventures we have entered into since January 1, 2008 as if they had occurred as of January 1, 2008 is not presented because it would not be materially different from the information presented in our accompanying consolidated statements of income.

3. Intangibles

Goodwill

We evaluate goodwill for impairment in accordance with the provisions of SFAS No. 142, "Goodwill and Other Intangible Assets (as amended)." For this purpose, we have six reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (iii) Natural Gas Pipelines; (iv) CO_2; (v) Terminals; and (vi) Kinder Morgan Canada.

Our goodwill impairment measurement date is May 31 of each year. There were no impairment charges resulting from our May 31, 2009 impairment testing, and no event indicating an impairment has occurred subsequent to that date. The fair value of each reporting unit was determined from the present value of the expected future cash flows from the applicable reporting unit (inclusive of a terminal value calculated using market multiples between six and ten times cash flows) discounted at a rate of 9.00%. In accordance with paragraph 23 of SFAS No. 142, the value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price that would be received to sell the unit as a whole in an orderly transaction between market participants at the measurement date.

Changes in the carrying amount of our goodwill for the six months ended June 30, 2009 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Terminals	Kinder Morgan Canada	Total
Balance as of December 31, 2008	$ 263.2	$ 288.4	$ 46.1	$ 257.6	$ 203.6	$ 1,058.9
Acquisitions and purchase price adjs.	—	—	—	10.6	—	10.6
Currency translation adjustments	—	—	—	—	9.7	9.7
Balance as of June 30, 2009	$ 263.2	$ 288.4	$ 46.1	$ 268.2	$ 213.3	$ 1,079.2

The increase in our goodwill since December 31, 2008 was related to our acquisition of certain terminal assets from Megafleet Towing Co., Inc. on April 23, 2009, and to increases resulting from changes in foreign currency rates since the end of last year. For more information on our Megafleet acquisition, see Note 2.

In addition, we identify any premium or excess cost we pay over our proportionate share of the underlying fair value of net assets acquired and accounted for as investments under the equity method of accounting. This premium or excess cost is referred to as equity method goodwill and is also not subject to amortization but rather to impairment testing in accordance with APB No. 18, “The Equity Method of Accounting for Investments in Common Stock (as amended).” As of both June 30, 2009 and December 31, 2008, we reported $138.2 million in equity method goodwill within the caption “Investments” in our accompanying consolidated balance sheets.

Other Intangibles

Excluding goodwill, our other intangible assets include customer relationships, contracts and agreements, technology-based assets, and lease value. These intangible assets have definite lives, are being amortized on a straight-line basis over their estimated useful lives, and are reported separately as “Other intangibles, net” in our accompanying consolidated balance sheets. Following is information related to our intangible assets subject to amortization (in millions):

	June 30, 2009	December 31, 2008
Customer relationships, contracts and agreements		
Gross carrying amount	$ 247.6	$ 246.0
Accumulated amortization	(57.8)	(51.1)
Net carrying amount	189.8	194.9
Technology-based assets, lease value and other		
Gross carrying amount	15.7	13.3
Accumulated amortization	(2.6)	(2.4)
Net carrying amount	13.1	10.9
Total Other intangibles, net	$ 202.9	$ 205.8

For the three and six months ended June 30, 2009, the amortization expense on our intangibles totaled $3.4 million and $6.9 million, respectively, and for the same prior year periods, the amortization expense on our intangibles totaled $3.7 million and $7.2 million, respectively. As of June 30, 2009, the weighted average amortization period for our intangible assets was approximately 16.8 years. Our estimated amortization expense for these assets for each of the next five fiscal years (2010 – 2014) is approximately $14.0 million, $13.8 million, $13.6 million, $13.5 million and $13.3 million, respectively.

4. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments or as of the earliest put date available to our debt holders. As of June 30, 2009, our outstanding short-term debt was $145.4 million, and our outstanding long-term debt (excluding the value of interest rate swap agreements) was $9,254.4 million. The weighted average interest rate on all of our borrowings (both short- and long-term) was approximately 4.57% during the second quarter of 2009 and approximately 5.35% during the second quarter of 2008. For the first six months of 2009 and 2008, the weighted average interest rate on all of our borrowings was approximately 4.82% and 5.55%, respectively.

Our outstanding short-term debt balance consisted of (i) $100 million in outstanding borrowings under our bank credit facility as of June 30, 2009 (discussed below); (ii) $23.7 million in principal amount of tax-exempt bonds that mature on April 1, 2024, but are due on demand pursuant to certain standby purchase agreement provisions contained in the bond indenture (our subsidiary Kinder Morgan Operating L.P. “B” is the obligor on the bonds); (iii) a $9.7 million portion of a 5.40% long-term note payable (our subsidiaries Kinder Morgan Operating L.P. “A” and Kinder Morgan Canada Company are the obligors on the note); (iv) a $6.7 million portion of 5.23% senior notes (our subsidiary Kinder Morgan Texas Pipeline, L.P. is the obligor on the notes); and (v) $5.3 million in principal amount of adjustable rate industrial development revenue bonds that mature on January 1, 2010 (the bonds were issued by the Illinois Development Finance Authority and our subsidiary Arrow Terminals L.P. is the obligor on the bonds).

Credit Facility

Our $1.85 billion unsecured bank credit facility is with a syndicate of financial institutions, and Wachovia Bank, National Association is the administrative agent. The credit facility permits us to obtain bids for fixed rate loans from members of the lending syndicate. Interest on our credit facility accrues at our option at a floating rate equal to either (i) the administrative agent's base rate (but not less than the Federal Funds Rate, plus 0.5%); or (ii) LIBOR, plus a margin, which varies depending upon the credit rating of our long-term senior unsecured debt. During the first quarter of 2009, following Lehman Brothers Holdings Inc.'s filing for bankruptcy protection in September 2008, we amended the credit facility to remove Lehman Brothers Commercial Bank as a lender, thus reducing the facility by $63.3 million. The commitments of the other banks remain unchanged, and the facility is not defaulted.

The credit facility matures August 18, 2010 and can be amended to allow for borrowings up to $2.0 billion. Borrowings under our credit facility can be used for partnership purposes and as a backup for our commercial paper program. The outstanding balance under our credit facility was $100 million as of June 30, 2009. As of December 31, 2008, there were no borrowings under the credit facility.

Additionally, as of June 30, 2009, the amount available for borrowing under our credit facility was reduced by an aggregate amount of $308.7 million, consisting of (i) a $100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) a combined $90.8 million in three letters of credit that support tax-exempt bonds; (iii) a combined $80 million in two letters of credit that support our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil; (iv) a $21.4 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (v) a combined $16.5 million in other letters of credit supporting other obligations of us and our subsidiaries.

Commercial Paper Program

On October 13, 2008, Standard & Poor's Rating Services lowered our short-term credit rating to A-3 from A-2. Additionally, on May 6, 2009, Moody's downgraded our commercial paper rating to Prime-3 from Prime-2 and assigned a negative outlook to our long-term credit rating. As a result of these revisions and current commercial paper market conditions, we are currently unable to access commercial paper borrowings, and as of both June 30, 2009 and December 31, 2008, we had no commercial paper borrowings. However, we expect that our financing and liquidity needs will continue to be met through borrowings made under our bank credit facility described above.

Senior Notes

On February 1, 2009, we paid $250 million to retire the principal amount of our 6.30% senior notes that matured on that date. We borrowed the necessary funds under our bank credit facility.

On May 14, 2009, we completed an additional public offering of senior notes. We issued a total of $1 billion in principal amount of senior notes in two separate series, consisting of $300 million of 5.625% notes due February 15, 2015, and $700 million of 6.85% notes due February 15, 2020. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $993.3 million, and we used the proceeds to reduce the borrowings under our bank credit facility.

Kinder Morgan Operating L.P. "A" Debt

Effective January 1, 2007, we acquired the remaining approximately 50.2% interest in the Cochin pipeline system that we did not already own. As part of our purchase price consideration, two of our subsidiaries issued a long-term note payable to the seller having a fair value of $42.3 million. We valued the debt equal to the present value of amounts to be paid, determined using an annual interest rate of 5.40%. Our subsidiaries Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company are the obligors on the note, and the principal amount of the note, along with interest, is due in five annual installments of $10.0 million beginning March 31, 2008. The final payment is due March 31, 2012. As of December 31, 2008, the measured present value (representing the outstanding balance on our balance sheet) of the note was $36.6 million. We paid the second installment on March 31, 2009, and as of June 30, 2009, the measured present value of the note was $27.4 million.

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 6.

Contingent Debt

As prescribed by the provisions of Financial Accounting Standards Board Interpretation (FIN) No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," we disclose certain types of guarantees or indemnifications we have made. These disclosures cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote. The following is a description of our contingent debt agreements as of June 30, 2009.

Cortez Pipeline Company Debt

Pursuant to a certain Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company (Kinder Morgan CO_2 Company, L.P. – 50% partner; a subsidiary of Exxon Mobil Corporation – 37% partner; and Cortez Vickers Pipeline Company – 13% partner) are required, on a several, proportional percentage ownership basis, to contribute capital to Cortez Pipeline Company in the event of a cash deficiency. Furthermore, due to our indirect ownership of Cortez Pipeline Company through Kinder Morgan CO_2 Company, L.P., we severally guarantee 50% of the debt of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company.

As of June 30, 2009, the debt facilities of Cortez Capital Corporation consisted of (i) $42.9 million of Series D notes due May 15, 2013; (ii) a $125 million short-term commercial paper program; and (iii) a $125 million committed revolving credit facility due December 22, 2009 (to support the above-mentioned $125 million commercial paper program). In October 2008, Standard & Poor's Rating Services lowered Cortez Capital Corporation's short-term credit rating to A-3 from A-2. As a result of this revision and current commercial paper market conditions, Cortez is unable to access commercial paper borrowings; however, it expects that its financing and liquidity needs will continue to be met through borrowings made under its bank credit facility.

As of June 30, 2009, in addition to the $42.9 million of outstanding Series D notes, Cortez Capital Corporation had outstanding borrowings of $120 million under its credit facility. Accordingly, as of June 30, 2009, our contingent share of Cortez's debt was $81.5 million (50% of total guaranteed borrowings).

With respect to Cortez's Series D notes, the average interest rate on the notes is 7.14%, and the outstanding $42.9 million principal amount of the notes is due in four equal annual installments of approximately $10.7 million beginning May 2010. Shell Oil Company shares our several guaranty obligations jointly and severally; however, we are obligated to indemnify Shell for liabilities it incurs in connection with such guaranty. As of June 30, 2009, JP Morgan Chase has issued a letter of credit on our behalf in the amount of $21.4 million to secure our indemnification obligations to Shell for 50% of the $42.9 million in principal amount of Series D notes outstanding as of that date.

Nassau County, Florida Ocean Highway and Port Authority Debt

We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year and corresponding reductions are made to the letter of credit. As of June 30, 2009, this letter of credit had a face amount of $21.2 million.

Rockies Express Pipeline LLC Debt

Pursuant to certain guaranty agreements, all three member owners of West2East Pipeline LLC (which owns all of the member interests in Rockies Express Pipeline LLC) have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in West2East Pipeline LLC, borrowings under Rockies Express' (i) $2.0 billion five-year, unsecured revolving credit facility due April 28, 2011; (ii) $2.0 billion commercial paper program; and (iii) $600 million in principal amount of floating rate senior notes due August 20, 2009. The three member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan W2E Pipeline LLC – 51%, a subsidiary of Sempra Energy – 25%, and a subsidiary of ConocoPhillips – 24%.

Borrowings under the Rockies Express commercial paper program and/or its credit facility are primarily used to finance the construction of the Rockies Express interstate natural gas pipeline and to pay related expenses. The credit facility, which can be amended to allow for borrowings of up to $2.5 billion, supports borrowings under the commercial paper program, and borrowings under the commercial paper program reduce the borrowings allowed under the credit facility. Lehman Brothers Commercial Bank was a lending bank with a $41 million commitment under Rockies Express Pipeline LLC's $2.0 billion credit facility, and during the first quarter of 2009, Rockies Express amended its facility to remove Lehman Brothers Commercial Bank as a lender, thus reducing the facility by $41.0 million. However, the commitments of the other banks remain unchanged, and the facility is not defaulted.

In October 2008, Standard & Poor's Rating Services lowered Rockies Express Pipeline LLC's short-term credit rating to A-3 from A-2. As a result of this revision and current commercial paper market conditions, Rockies Express is unable to access commercial paper borrowings; however, it expects that its financing and liquidity needs will continue to be met through both borrowings made under its long-term bank credit facility and contributions by its equity investors.

The $600 million in principal amount of senior notes were issued on September 20, 2007. The notes are unsecured and are not redeemable prior to maturity. Interest on the notes is paid and computed quarterly at an interest rate of three-month LIBOR (with a floor of 4.25%) plus a spread of 0.85%. Upon maturity on August 20, 2009, we expect that Rockies Express will repay these senior notes from equity contributions received from its equity investors. In addition, as of June 30, 2009, Rockies Express was a party to a floating-to-fixed interest rate swap agreement having a notional principal amount of $300 million and a maturity date of August 20, 2009. The interest rate swap agreement effectively converts the interest expense associated with $300 million of these senior notes from its stated variable rate to a fixed rate of 5.47%.

As of June 30, 2009, in addition to the $600 million in floating rate senior notes, Rockies Express had outstanding borrowings of $1,883.2 million under its credit facility. Accordingly, as of June 30, 2009, our contingent share of Rockies Express' debt was $1,266.4 million (51% of total guaranteed borrowings).

Midcontinent Express Pipeline LLC Debt

Pursuant to certain guaranty agreements, each of the two member owners of Midcontinent Express Pipeline LLC have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in Midcontinent Express Pipeline LLC, borrowings under Midcontinent's $1.4 billion three-year, unsecured revolving credit facility, entered into on February 29, 2008 and due February 28, 2011. The facility is with a syndicate of financial institutions with The Royal Bank of Scotland plc as the administrative agent. Borrowings under the credit facility are used to finance the construction of the Midcontinent Express Pipeline system and to pay related expenses**.** Lehman Brothers Commercial Bank was a lending bank with a $100 million commitment to the Midcontinent Express $1.4 billion credit facility. Since declaring bankruptcy, Lehman Brothers Commercial Bank has not met its obligations to lend under the credit facility; effectively reducing borrowing capacity under this facility by Lehman's commitment amount that has not been funded in previous borrowings. The commitments of the other banks remain unchanged and the facility is not defaulted.

Midcontinent Express Pipeline LLC is an equity method investee of ours, and the two member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan Operating L.P. "A" – 50%, and Energy Transfer Partners, L.P. – 50%. As of June 30, 2009, Midcontinent Express Pipeline LLC had outstanding borrowings of $1,190.9 million under its three-year credit facility. Accordingly, as of June 30, 2009, our contingent share of Midcontinent Express' debt was $595.5 million (50% of total borrowings).

Furthermore, the credit facility can be used for the issuance of letters of credit to support the construction of the Midcontinent Express Pipeline, and as of June 30, 2009, a letter of credit having a face amount of $33.3 million was issued under the credit facility. Accordingly, as of June 30, 2009, our contingent responsibility with regard to this outstanding letter of credit was $16.7 million (50% of total face amount).

For additional information regarding our debt facilities and our contingent debt agreements, see Note 9 to our consolidated financial statements included in our 2008 Form 10-K.

5. Partners' Capital

Limited Partner Units

As of June 30, 2009 and December 31, 2008, our partners' capital included the following limited partner units:

	June 30, 2009	December 31, 2008
Common units	197,051,126	182,969,427
Class B units	5,313,400	5,313,400
i-units	81,940,303	77,997,906
Total limited partner units	284,304,829	266,280,733

The total limited partner units represent our limited partners' interest and an effective 98% ownership interest in us, exclusive of our general partner's incentive distribution rights. Our general partner has an effective 2% ownership interest in us, excluding its incentive distribution rights.

As of June 30, 2009, our total common units consisted of 180,680,698 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner. As of December 31, 2008, our common unit total consisted of 166,598,999 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner) and 1,724,000 units held by our general partner.

On both June 30, 2009 and December 31, 2008, all of our 5,313,400 Class B units were held by a wholly-owned subsidiary of KMI. The Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange. All of our Class B units were issued to a wholly-owned subsidiary of KMI in December 2000.

On both June 30, 2009 and December 31, 2008, all of our i-units were held by KMR. Our i-units are a separate class of limited partner interests in us and are not publicly traded. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common units.

Changes in Partners' Capital

For each of the three and six month periods ended June 30, 2009 and 2008, changes in the carrying amounts of our Partners' Capital attributable to both us and our noncontrolling interests, including our comprehensive income (loss) are summarized as follows (in millions):

	Three Months Ended June 30,					
	2009			2008		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 6,145.5	$ 71.6	$ 6,217.1	$ 4,539.5	$ 55.5	$ 4,595.0
Units issued as consideration in the acquisition of assets	5.0	-	5.0	-	-	-
Units issued for cash	381.6	-	381.6	-	-	-
Distributions paid in cash	(430.8)	(5.4)	(436.2)	(363.4)	(4.7)	(368.1)
Trans Mountain Pipeline acquisition	25.7	0.3	26.0	23.2	0.2	23.4
Express/Jet Fuel Pipelines acquisition	(4.6)	-	(4.6)	-	-	-
Kinder Morgan North 40 terminal land acquisition	(0.9)	-	(0.9)	-	-	-
KMI going-private transaction expenses	1.4	-	1.4	-	-	-
Cash contributions	-	4.8	4.8	-	1.1	1.1
Other adjustments	(0.2)	-	(0.2)	-	0.3	0.3
Comprehensive income (loss):						
Net Income	323.8	4.8	328.6	362.2	4.1	366.3
Other comprehensive loss:						
Change in fair value of derivatives utilized for hedging purposes	(336.1)	(3.4)	(339.5)	(1,648.7)	(16.9)	(1,665.6)
Reclassification of change in fair value of derivatives to net income	30.3	0.3	30.6	261.8	2.8	264.6
Foreign currency translation adjustments	127.1	1.3	128.4	11.2	-	11.2
Adjustments to pension and other postretirement benefit plan liabilities	(0.1)	-	(0.1)	(0.1)	0.1	-
Total other comprehensive loss	(178.8)	(1.8)	(180.6)	(1,375.8)	(14.0)	(1,389.8)
Comprehensive income (loss)	145.0	3.0	148.0	(1,013.6)	(9.9)	(1,023.5)
Ending Balance	$ 6,267.7	$ 74.3	$ 6,342.0	$ 3,185.7	$ 42.5	$ 3,228.2

	Six Months Ended June 30,					
	2009			2008		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 6,045.6	$ 70.7	$ 6,116.3	$ 4,435.7	$ 54.2	$ 4,489.9
Units issued as consideration pursuant to common unit compensation plan for non-employee directors	0.2	-	0.2	0.3	-	0.3
Units issued as consideration in the acquisition of assets	5.0	-	5.0	-	-	-
Units issued for cash	669.2	-	669.2	384.0	-	384.0
Distributions paid in cash	(848.1)	(10.8)	(858.9)	(697.5)	(8.9)	(706.4)
Trans Mountain Pipeline acquisition	25.7	0.3	26.0	23.2	0.2	23.4
Express/Jet Fuel Pipelines acquisition	(1.9)	-	(1.9)	-	-	-
Kinder Morgan North 40 terminal land acquisition	(0.9)	-	(0.9)	-	-	-
KMI going-private transaction expenses	2.8	-	2.8	-	-	-
Cash contributions	-	8.6	8.6	-	5.9	5.9
Other adjustments	(0.2)	-	(0.2)	-	-	-
Comprehensive income (loss):						
Net Income	587.7	7.7	595.4	708.9	8.1	717.0
Other comprehensive loss:						
Change in fair value of derivatives utilized for hedging purposes	(300.6)	(3.0)	(303.6)	(2,051.5)	(21.0)	(2,072.5)
Reclassification of change in fair value of derivatives to net income	13.2	0.1	13.3	422.6	4.4	427.0
Foreign currency translation adjustments	72.9	0.7	73.6	(43.4)	(0.5)	(43.9)
Adjustments to pension and other postretirement benefit plan liabilities	(2.9)	-	(2.9)	3.4	0.1	3.5
Total other comprehensive loss	(217.4)	(2.2)	(219.6)	(1,668.9)	(17.0)	(1,685.9)
Comprehensive income (loss)	370.3	5.5	375.8	(960.0)	(8.9)	(968.9)
Ending Balance	$ 6,267.7	$ 74.3	$ 6,342.0	$ 3,185.7	$ 42.5	$ 3,228.2

Additionally, during the first six months of both 2009 and 2008, there were no material changes in our ownership interests in subsidiaries in which we retained a controlling financial interest.

Equity Issuances

On January 16, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC. According to the provisions of this agreement, we may offer and sell from time to time common units having an aggregate offering value of up to $300 million through UBS, as sales agent. Sales of the units will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we also may sell common units to UBS as principal for its own account at a price agreed upon at the time of the sale. Any sale of common units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS.

This Equity Distribution Agreement provides us the right, but not the obligation, to sell common units in the future, at prices we deem appropriate. We retain at all times complete control over the amount and the timing of each sale, and we will designate the maximum number of common units to be sold through UBS, on a daily basis or otherwise as we and UBS agree. UBS will then use its reasonable efforts to sell, as our sales agent and on our behalf, all of the designated common units. We may instruct UBS not to sell common units if the sales cannot be effected at or above the price designated by us in any such instruction. Either we or UBS may suspend the offering of common units pursuant to the agreement by notifying the other party. During the three and six months ended

June 30, 2009, we issued 1,944,664 and 2,556,747, respectively, of our common units pursuant to this agreement. After commissions of $1.7 million and $2.3 million, respectively, for the three and six month periods, we received net proceeds from the issuance of these common units of approximately $94.7 million and $124.6 million. We used the proceeds to reduce the borrowings under our bank credit facility.

We also completed two separate underwritten public offerings of our common units in the first half of 2009, and in April 2009, we issued 105,752 common units—valued at $5.0 million—as the purchase price for additional ownership interests in certain oil and gas properties.

In our first 2009 public offering, completed in March, we issued 5,666,000 of our common units at a price of $46.95 per unit, less underwriting commissions and expenses. We received net proceeds of $258.0 million for the issuance of these common units, and we used the proceeds to reduce the borrowings under our bank credit facility.

Secondly, on June 12, 2009, we issued 5,750,000 of our common units at a price of $51.50 per unit, less underwriting commissions and expenses. We received net proceeds of $286.9 million for the issuance of these common units, and we used the proceeds to reduce the borrowings under our bank credit facility.

Income Allocation and Declared Distributions

For the purposes of maintaining partner capital accounts, our partnership agreement specifies that items of income and loss shall be allocated among the partners, other than owners of i-units, in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to our general partner. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash and i-units being distributed.

On May 15, 2009, we paid a cash distribution of $1.05 per unit to our common unitholders and our Class B unitholders for the quarterly period ended March 31, 2009. KMR, our sole i-unitholder, received a distribution of 2,025,208 i-units from us on May 15, 2009, based on the preceding discussion of our i-units and the $1.05 per unit distributed to our common unitholders on that date. The distributions were declared on April 15, 2009, payable to unitholders of record as of April 30, 2009.

On July 15, 2009, we declared a cash distribution of $1.05 per unit for the quarterly period ended June 30, 2009. The distribution will be paid on August 14, 2009, to unitholders of record as of July 31, 2009. Our common unitholders and Class B unitholders will receive cash. KMR will receive a distribution of 1,814,650 additional i-units based on the $1.05 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.022146) will be issued. This fraction was determined by dividing:

- $1.05, the cash amount distributed per common unit

by

- $47.412, the average of KMR's shares' closing market prices from July 15-28, 2009, the ten consecutive trading days preceding the date on which the shares began to trade ex-dividend under the rules of the New York Stock Exchange.

Incentive distributions allocated to our general partner are determined by the amount quarterly distributions to unitholders exceed certain specified target levels. Our distribution of $1.05 per unit paid on May 15, 2009 for the first quarter of 2009 required an incentive distribution to our general partner of $223.2 million. Our distribution of $0.96 per unit paid on May 15, 2008 for the first quarter of 2008 resulted in an incentive distribution payment to our general partner in the amount of $185.8 million. The increased incentive distribution to our general partner paid for the first quarter of 2009 over the incentive distribution paid for the first quarter of 2008 reflects the increase in the amount distributed per unit as well as the issuance of additional units.

Our declared distribution for the second quarter of 2009 of $1.05 per unit will result in an incentive distribution to our general partner of $231.8 million. This compares to our distribution of $0.99 per unit and incentive distribution to our general partner of $194.2 million for the second quarter of 2008.

Subsequent Event

At the time of our June 12, 2009 public common unit offering, discussed above in "—Equity Issuances," we granted the underwriters a 30-day option to purchase up to an additional 862,500 common units from us on the same terms and conditions, and pursuant to the exercise of this option, we issued an additional 862,500 common units on July 6, 2009. After underwriting commissions and expenses, we received net proceeds of $43.0 million for the issuance of these 862,500 common units, and we used the proceeds to reduce the borrowings under our bank credit facility.

6. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, natural gas liquids and crude oil. We also have exposure to interest rate risk as a result of the issuance of our debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to certain of these risks.

Energy Commodity Price Risk Management

We are exposed to risks associated with changes in the market price of natural gas, natural gas liquids and crude oil as a result of the forecasted purchase or sale of these products. Specifically, these risks are associated with unfavorable price volatility related to (i) pre-existing or anticipated physical natural gas, natural gas liquids and crude oil sales; (ii) natural gas purchases; and (iii) natural gas system use and storage. The unfavorable price changes are often caused by shifts in the supply and demand for these commodities, as well as their locations.

Our principal use of energy commodity derivative contracts is to mitigate the risk associated with unfavorable market movements in the price of energy commodities. Our energy commodity derivative contracts act as a hedging (offset) mechanism against the volatility of energy commodity prices by allowing us to transfer this price risk to counterparties who are able and willing to bear it.

For derivative contracts that are designated and qualify as cash flow hedges pursuant to generally accepted accounting principles, the portion of the gain or loss on the derivative contract that is effective in offsetting the variable cash flows associated with the hedged forecasted transaction is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction and in the same period or periods during which the hedged transaction affects earnings (e.g., in "revenues" when the hedged transactions are commodity sales). The remaining gain or loss on the derivative contract in excess of the cumulative change in the present value of future cash flows of the hedged item, if any (i.e., the ineffective portion), is recognized in earnings during the current period. We currently do not exclude any component of the derivative contracts' gain or loss from the assessment of hedge effectiveness.

During the three and six months ended June 30, 2009, we reclassified losses of $30.6 million and $13.3 million, respectively, of "Accumulated other comprehensive loss" into earnings, and for the same comparable periods last year, we reclassified losses of $264.6 million and $427.0 million, respectively into earnings. All amounts reclassified into net income during the first six months of both years resulted from the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred). No amounts were reclassified into earnings as a result of the discontinuance of cash flow hedges because it was probable that the original forecasted transactions would not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. The proceeds or payments resulting from the settlement of cash flow hedges are reflected in the operating section of our statement of cash flows as changes to net income and working capital.

Our consolidated "Accumulated other comprehensive loss" balance was $505.1 million as of June 30, 2009, and $287.7 million as of December 31, 2008. These consolidated totals included "Accumulated other comprehensive loss" amounts associated with energy commodity price risk management activities of $351.7 million as of June 30, 2009 and $63.2 million as of December 31, 2008. Approximately $169.8 million of the total amount associated with our energy commodity price risk management activities as of June 30, 2009 is expected to be reclassified into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur). As of June 30, 2009, the maximum length of time over which we have hedged our exposure to the variability in future cash flows associated with energy commodity price risk is through April 2013.

As of June 30, 2009, we had entered into the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Notional Quantity
Derivatives designated as hedging contracts under SFAS No. 133	
Crude oil	28.0 million barrels
Natural gas(a)	43.6 billion cubic feet
Derivatives not designated as hedging contracts under SFAS No. 133	
Crude oil	0.1 million barrels
Natural gas(a)	7.1 billion cubic feet

(a) Notional quantities are shown net.

For derivative contracts that are not designated as a hedge for accounting purposes, all realized and unrealized gains and losses are recognized in the statement of income during the current period. These types of transactions include basis spreads, basis-only positions and gas daily swap positions. We primarily enter into these positions to economically hedge an exposure through a relationship that does not qualify for hedge accounting. This will result in non-cash gains or losses being reported in our operating results.

Effective at the beginning of the second quarter of 2008, we determined that the derivative contracts of our Casper and Douglas natural gas processing operations that previously had been designated as cash flow hedges for accounting purposes no longer met the hedge effectiveness assessment as required by accounting principles. Consequently, we discontinued hedge accounting treatment for these relationships (primarily crude oil hedges of heavy natural gas liquids sales) effective March 31, 2008. Since the forecasted sales of natural gas liquids volumes (the hedged item) are still expected to occur, all of the accumulated losses through March 31, 2008 on the related derivative contracts remained in accumulated other comprehensive income, and will not be reclassified into earnings until the physical transactions occur. Any changes in the value of these derivative contracts subsequent to March 31, 2008 will no longer be deferred in other comprehensive income, but rather will impact current period income.

Interest Rate Risk Management

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. We use interest rate swap agreements to manage the interest rate risk associated with the fair value of our fixed rate borrowings and to effectively convert a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate cash flows in order to achieve our desired mix of fixed and variable rate debt.

Since the fair value of fixed rate debt varies inversely with changes in the market rate of interest, we enter into swap agreements to receive a fixed and pay a variable rate of interest in order to convert the interest expense associated with certain of our senior notes from fixed rates to variable rates, resulting in future cash flows that vary with the market rate of interest. These swaps, therefore, hedge against changes in the fair value of our fixed rate debt that result from market interest rate changes. For derivative contracts that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings.

As of December 31, 2008, we were a party to interest rate swap agreements with a total notional principal amount of $2.8 billion. During the first six months of 2009, we both terminated an existing fixed-to-variable interest rate swap agreement having a notional principal amount of $300 million and a maturity date of March 15, 2031, and entered into twelve separate fixed-to-variable swap agreements having a combined notional principal amount of $2.45 billion. We received proceeds of $144.4 million from the early termination of the $300 million swap agreement. In addition, an existing fixed-to-variable rate swap agreement having a notional principal amount of $250 million matured on February 1, 2009. This swap agreement corresponded with the maturity of our $250 million in principal amount of 6.30% senior notes that also matured on that date (discussed in Note 4).

Therefore, as of June 30, 2009, we had a combined notional principal amount of $4.7 billion of fixed-to-variable interest rate swap agreements effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of June 30, 2009, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through January 15, 2038.

Fair Value of Derivative Contracts

The fair values of our current and non-current asset and liability derivative contracts are each reported separately as "Fair value of derivative contracts" on our accompanying consolidated balance sheets. The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of June 30, 2009 and December 31, 2008 (in millions):

Fair Value of Derivative Contracts

	Asset Derivatives				Liability Derivatives			
	June 30, 2009		December 31, 2008		June 30, 2009		December 31, 2008	
	Balance sheet Location	Fair value	Balance sheet Location	Fair value	Balance sheet Location	Fair value	Balance sheet location	Fair Value
Derivatives designated as hedging contracts under SFAS No. 133								
Energy commodity derivative contracts	Current	$42.8	Current	$113.5	Current	$(226.7)	Current	$(129.4)
	Noncurrent	50.7	Noncurrent	48.9	Noncurrent	(234.4)	Noncurrent	(92.2)
Subtotal		93.5		162.4		(461.1)		(221.6)
Interest rate Swap agreements	Noncurrent	294.6	Noncurrent	747.1	Noncurrent	(161.7)	Noncurrent	—
Total		388.1		909.5		(622.8)		(221.6)
Derivatives not designated as hedging contracts under SFAS No. 133								
Energy commodity derivative contracts	Current	2.0	Current	1.8	Current	(1.9)	Current	(0.1)
Total derivatives		$390.1		$911.3		$(624.7)		$(221.7)

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within "Value of interest rate swaps" on our accompanying consolidated balance sheets, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of June 30, 2009 and December 31, 2008, this unamortized premium totaled $337.7 million and $204.2 million, respectively.

Effect of Derivative Contracts on the Income Statement

The following three tables summarize the impact of our derivative contracts on our accompanying consolidated statements of income for the three and six months ended June 30, 2009 and 2008 (in millions):

Derivatives in SFAS No. 133 fair value hedging relationships	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative(a)		Hedged items in SFAS No. 133 fair value hedging relationships	Location of gain/(loss) recognized in income on related hedged item	Amount of gain/(loss) recognized in income on related hedged items(a)	
		Three Months				Three Months	
		2009	2008			2009	2008
Interest rate swap agreements	Interest, net – income/(expense)	$(339.4)	$(128.2)	Fixed rate debt	Interest, net – income/(expense)	$339.4	$128.2
Total		$(339.4)	$(128.2)	**Total**		$339.4	$128.2
		Six Months				Six Months	
		2009	2008			2009	2008
Interest rate swap agreements	Interest, net – income/(expense)	$(469.8)	$(9.1)	Fixed rate debt	Interest, net – income/(expense)	$469.8	$9.1
Total		$(469.8)	$(9.1)	**Total**		$469.8	$9.1

(a) Amounts reflect the change in the fair value of interest rate swap agreements and the change in the fair value of the associated fixed rate debt which exactly offset each other as a result of no hedge ineffectiveness. Amounts do not reflect the impact on interest expense from the interest rate swap agreements under which we pay variable rate interest and receive fixed rate interest.

Derivatives in SFAS No. 133 cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)		Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)		Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	
	Three Months			Three Months			Three Months	
	2009	2008		2009	2008		2009	2008
Energy commodity derivative contracts	$(339.5)	$(1,665.6)	Revenues-Natural Gas sales	$4.8	$(3.3)	Revenues	$—	$ —
			Revenues-Product sales and other	(28.9)	(229.2)			
			Gas purchases and other costs of sales	(6.5)	(32.1)	Gas purchases and other costs of sales	—	—
Total	$(339.5)	$(1,665.6)	**Total**	$(30.6)	$(264.6)	**Total**	$—	$—
	Six Months			Six Months			Six Months	
	2009	2008		2009	2008		2009	2008
Energy commodity derivative contracts	$(303.6)	$(2,072.5)	Revenues-Natural Gas sales	$6.5	$(3.3)	Revenues	$—	$—
			Revenues-Product sales and other	(12.9)	(382.8)			
			Gas purchases and other costs of sales	(6.9)	(40.9)	Gas purchases and other costs of sales	—	(2.4)
Total	$(303.6)	$(2,072.5)	**Total**	$(13.3)	$(427.0)	**Total**	$—	$(2.4)

Derivatives not designated as hedging contracts under SFAS No. 133	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative	
		Three Months	
		2009	2008
Energy commodity derivative contracts	Gas purchases and other costs of sales	$(1.9)	$(13.1)
Total		$(1.9)	$(13.1)
		Six Months	
		2009	2008
Energy commodity derivative contracts	Gas purchases and other costs of sales	$(2.3)	$(13.1)
Total		$(2.3)	$(13.1)

Credit Risks

As discussed in Note 14 to our consolidated financial statements included in our 2008 Form 10-K, we have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings); (ii) collateral requirements under certain circumstances; and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on our policies, exposure, credit and other reserves, our management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

Our over-the-counter swaps and options are entered into with counterparties outside central trading organizations such as a futures, options or stock exchanges. These contracts are with a number of parties, all of which have investment grade credit ratings. While we enter into derivative transactions principally with investment grade counterparties and actively monitor their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future. The maximum potential exposure to credit losses on our derivative contracts as of June 30, 2009 was (in millions):

	Asset position
Interest rate swap agreements	$ 294.6
Energy commodity derivative contracts	95.5
Gross exposure	390.1
Netting agreement impact	(76.3)
Net exposure	$ 313.8

In conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of June 30, 2009 and December 31, 2008, we had outstanding letters of credit totaling $80 million and $40 million, respectively, in support of our hedging of energy commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil. Additionally, as of June 30, 2009, we had cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners totaling $21.8 million, and we reported this amount as "Restricted deposits" in our accompanying consolidated balance sheet. As of December 31, 2008, our counterparties associated with our energy commodity contract positions and over-the-counter swap agreements had margin deposits with us totaling $3.1 million, and we reported this amount within "Accrued other liabilities" in our accompanying consolidated balance sheet.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring us to post additional collateral upon a decrease in our credit rating. Based on contractual provisions as of June 30, 2009, we estimate that if our credit rating was downgraded, we would have the following additional collateral obligations (in millions):

Credit Ratings Downgraded(a)	Incremental obligations	Cumulative obligations(b)
One notch to BBB-/Baa3	$ 76.6	$ 178.4
Two notches to below BBB-/Baa3 (below investment grade)	$ 79.1	$ 257.5

(a) If there are split ratings among the independent credit rating agencies, most counterparties use the higher credit rating to determine our incremental collateral obligations, while the remaining use the lower credit rating. Therefore, a one notch downgrade to BBB-/Baa3 by one agency would not trigger the entire $76.6 million incremental obligation.
(b) Includes current posting at current rating.

7. Fair Value

Fair value measurements and disclosures are made in accordance with the provisions of SFAS No. 157, "Fair Value Measurements." While not requiring material new fair value measurements, SFAS No. 157 established a single definition of fair value in generally accepted accounting principles and expanded disclosures about fair value measurements. The provisions of this Statement apply to other accounting pronouncements that require or permit fair value measurements; the Financial Accounting Standards Board having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute.

On February 12, 2008, the FASB issued FASB Staff Position No. FAS 157-2, "Effective Date of FASB Statement No. 157," referred to as FAS 157-2 in this report. FAS 157-2 delayed the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

Accordingly, we adopted SFAS No. 157 for financial assets and financial liabilities effective January 1, 2008. The adoption did not have a material impact on our balance sheet, statement of income, or statement of cash flows since we already applied its basic concepts in measuring fair values. We adopted SFAS No. 157 for non-financial assets and non-financial liabilities effective January 1, 2009. This includes applying the provisions of SFAS No. 157 to (i) nonfinancial assets and liabilities initially measured at fair value in business combinations; (ii) reporting units or nonfinancial assets and liabilities measured at fair value in conjunction with goodwill impairment testing; (iii) other nonfinancial assets measured at fair value in conjunction with impairment assessments; and (iv) asset retirement obligations initially measured at fair value. The adoption did not have a material impact on our balance sheet, statement of income, or statement of cash flows since we already applied its basic concepts in measuring fair values.

SFAS No. 157 established a hierarchal disclosure framework associated with the level of pricing observability utilized in measuring fair value. This framework defined three levels of inputs to the fair value measurement process, and requires that each fair value measurement be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety. The three broad levels of inputs defined by the SFAS No. 157 hierarchy are as follows:

- Level 1 Inputs—quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;

- Level 2 Inputs—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and

▪ Level 3 Inputs—unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

The following tables summarize the fair value measurements of our (i) energy commodity derivative contracts; and (ii) interest rate swap agreements as of both June 30, 2009 and December 31, 2008, based on the three levels established by SFAS No. 157, and does not include cash margin deposits, which are reported as "Restricted deposits" in our accompanying consolidated balance sheets (in millions):

		Asset Fair Value Measurements Using		
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of June 30, 2009				
Energy commodity derivative contracts(a)..	$ 95.5	$ 0.1	$ 44.8	$ 50.6
Interest rate swap agreements......................	294.6	—	294.6	—
As of December 31, 2008				
Energy commodity derivative contracts(b)..	$ 164.2	$ 0.1	$ 108.9	$ 55.2
Interest rate swap agreements......................	747.1	—	747.1	—

		Liability Fair Value Measurements Using		
	Total	Quoted Prices in Active Markets for Identical Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of June 30, 2009				
Energy commodity derivative contracts(c)..	$ (463.0)	$ —	$ (436.4)	$ (26.6)
Interest rate swap agreements......................	(161.7)	—	(161.7)	—
As of December 31, 2008				
Energy commodity derivative contracts(d)..	$ (221.7)	$ —	$ (210.6)	$ (11.1)
Interest rate swap agreements......................	—	—	—	—

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC West Texas Intermediate hedges and OTC natural gas hedges that are settled on NYMEX. Level 3 consists primarily of natural gas basis swaps and West Texas Intermediate options.

(b) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC West Texas Intermediate hedges and OTC natural gas hedges that are settled on NYMEX. Level 3 consists primarily of West Texas Intermediate options and West Texas Sour hedges.

(c) Level 2 consists primarily of OTC West Texas Intermediate hedges and OTC natural gas hedges that are settled on NYMEX. Level 3 consists primarily of West Texas Sour hedges, natural gas basis swaps and West Texas Intermediate options.

(d) Level 2 consists primarily of OTC West Texas Intermediate hedges. Level 3 consists primarily of natural gas basis swaps, natural gas options and West Texas Intermediate options.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for the three and six months ended June 30, 2009 and 2008 (in millions):

Significant Unobservable Inputs (Level 3)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Derivatives-net asset/(liability)				
Beginning of Period	$ 53.4	$ (123.8)	$ 44.1	$ (100.3)
Realized and unrealized net losses	(28.1)	(141.5)	(21.8)	(186.3)
Purchases and settlements	(1.3)	32.3	1.7	53.6
Transfers in (out) of Level 3	—	—	—	—
End of Period	$ 24.0	$ (233.0)	$ 24.0	$ (233.0)
Change in unrealized net losses relating to contracts still held at end of period	$ (29.7)	$ (123.1)	$ (39.5)	$ (160.8)

Fair Value of Financial Instruments

Fair value as used in SFAS No. 107, "Disclosures About Fair Value of Financial Instruments," represents the amount at which an instrument could be exchanged in a current transaction between willing parties. The estimated fair value of our outstanding debt balance as of June 30, 2009 and December 31, 2008 (both short- and long-term, but excluding the value of interest rate swaps), is disclosed below (in millions):

	June 30, 2009		December 31, 2008	
	Carrying Value	**Estimated Fair Value**	**Carrying Value**	**Estimated Fair Value**
Total Debt	$ 9,399.8	$ 9,427.3	$ 8,563.6	$ 7,627.3

The estimated fair value of our outstanding publicly-traded debt as of each date is based upon quoted market prices, if available, and for all other debt, fair value is based upon prevailing interest rates currently available to us. In accordance with the provisions of SFAS No. 157, we adjust (discount) the fair value measurement of our long-term debt for the effect of credit risk. For a more complete discussion of our fair value measurements, see Note 14 to our consolidated financial statements included in our 2008 Form 10-K.

8. Reportable Segments

We divide our operations into five reportable business segments. These segments and their principal source of revenues are as follows:

- Products Pipelines— the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids;
- Natural Gas Pipelines—the sale, transport, processing, treating, storage and gathering of natural gas;
- CO_2—the production and sale of crude oil from fields in the Permian Basin of West Texas and the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields;
- Terminals—the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals; and
- Kinder Morgan Canada—the transportation of crude oil and refined products.

We evaluate performance principally based on each segments' earnings before depreciation, depletion and amortization, which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income and income tax expense, and net income attributable to noncontrolling interests. Our reportable segments are strategic business units that offer different products and services. Each segment is managed separately because each segment involves different products and marketing strategies.

In addition, due to the October 2007 sale of our North System natural gas liquids pipeline and our 50% ownership interest in the Heartland Pipeline Company (collectively referred to in this report as our North System), we accounted for the North System business as a discontinued operation. Previous to the sale, the North System's operating results were included as part of our Products Pipelines business segment, and consistent with the management approach of identifying and reporting discrete financial information on operating segments, we have included adjustments to the gain on disposal of the North System (a $0.8 million increase in the second quarter of 2008 and a $1.3 million increase in the first six months of 2008) within our Products Pipelines business segment disclosures presented in this report for the first six months of 2008. Except for these gain adjustments, we recorded no other financial results from the operations of the North System during the first six months of 2008.

Selected financial information by segment follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues				
Products Pipelines				
Revenues from external customers	$ 206.7	$ 198.6	$ 394.9	$ 396.9
Natural Gas Pipelines				
Revenues from external customers	860.7	2,644.7	1,912.4	4,557.2
CO_2				
Revenues from external customers	258.2	308.6	487.1	595.0
Terminals				
Revenues from external customers	263.7	300.4	531.4	580.4
Intersegment revenues	0.3	0.3	0.5	0.5
Kinder Morgan Canada				
Revenues from external customers	56.0	43.4	106.0	86.5
Total segment revenues	1,645.6	3,496.0	3,432.3	6,216.5
Less: Total intersegment revenues	(0.3)	(0.3)	(0.5)	(0.5)
Total consolidated revenues	$ 1,645.3	$ 3,495.7	$ 3,431.8	$ 6,216.0
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)				
Products Pipelines	$ 155.0	$ 137.6	$ 300.4	$ 278.3
Natural Gas Pipelines	162.1	182.5	362.9	370.7
CO_2	202.7	216.6	370.1	416.4
Terminals	142.9	140.4	277.6	266.2
Kinder Morgan Canada	46.7	33.4	66.2	63.6
Total segment earnings before DD&A	709.4	710.5	1,377.2	1,395.2
Total segment depreciation, depletion and amortization	(203.1)	(165.6)	(413.3)	(323.7)
Total segment amortization of excess cost of investments	(1.5)	(1.5)	(2.9)	(2.9)
General and administrative expenses	(72.6)	(72.8)	(155.1)	(149.6)
Unallocable interest expense, net of interest income	(101.3)	(99.9)	(205.9)	(197.6)
Unallocable income tax expense	(2.3)	(4.4)	(4.6)	(4.4)
Total consolidated net income	$ 328.6	$ 366.3	$ 595.4	$ 717.0

	June 30, 2009	December 31, 2008
Assets		
Products Pipelines	$ 4,229.5	$ 4,183.0
Natural Gas Pipelines	6,307.1	5,535.9
CO_2	2,263.3	2,339.9
Terminals	3,483.6	3,347.6
Kinder Morgan Canada	1,632.0	1,583.9
Total segment assets	17,915.5	16,990.3
Corporate assets(b)	539.2	895.5
Total consolidated assets	$ 18,454.7	$ 17,885.8

(a) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).

(b) Includes cash and cash equivalents; margin and restricted deposits; unallocable interest receivable, prepaid assets and deferred charges; and risk management assets related to the fair value of interest rate swaps.

9. Related Party Transactions

Plantation Pipe Line Company Note Receivable

We have a long-term note receivable bearing interest at the rate of 4.72% per annum from Plantation Pipe Line Company, our 51.17%-owned equity investee. The note provides for semiannual payments of principal and interest on December 31 and June 30 each year, with a final principal payment due July 20, 2011. The outstanding note receivable balance was $86.1 million as of June 30, 2009, and $88.5 million as of December 31, 2008. Of these amounts, $2.6 million and $3.7 million were included within "Accounts, notes and interest receivable, net," on our accompanying consolidated balance sheets as of June 30, 2009 and December 31, 2008, respectively, and the remainder was included within "Notes receivable" at each reporting date.

Express US Holdings LP Note Receivable

In conjunction with the acquisition of our 33 1/3% equity ownership interest in the Express pipeline system from KMI on August 28, 2008, we acquired a long-term investment in a C$113.6 million debt security issued by Express US Holdings LP (the obligor), the partnership that maintains ownership of the U.S. portion of the Express pipeline system. As of our acquisition date, the value of this unsecured debenture was equal to KMI's carrying value of $107.0 million. The debenture is denominated in Canadian dollars, due in full on January 9, 2023, bears interest at the rate of 12.0% per annum, and provides for quarterly payments of interest in Canadian dollars on March 31, June 30, September 30 and December 31 each year. As of June 30, 2009 and December 31, 2008, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was $97.7 million and $93.3 million, respectively, and we included these amounts within "Notes receivable" on our accompanying consolidated balance sheets.

KMI

Asset Contributions

In conjunction with our acquisition of (i) certain Natural Gas Pipelines assets and partnership interests from KMI in December 1999 and December 2000; and (ii) all of the partnership interest in TransColorado Gas Transmission Company from two wholly-owned subsidiaries of KMI on November 1, 2004, KMI agreed to indemnify us and Kinder Morgan G.P., Inc. with respect to approximately $733.5 million of our debt. KMI would be obligated to perform under this indemnity only if we are unable and/or our assets are insufficient to satisfy our obligations.

Significant Investors' Fair Value of Energy Commodity Derivative Contracts

As a result of the May 2007 going-private transaction of KMI (formerly Knight Inc.), as discussed in our 2008 Form 10-K, a number of individuals and entities became significant investors in KMI. By virtue of the size of their ownership interest in KMI, two of those investors became "related parties" to us (as that term is defined in authoritative accounting literature): (i) American International Group, Inc., referred to in this report as AIG, and certain of its affiliates; and (ii) Goldman Sachs Capital Partners and certain of its affiliates.

We and/or our affiliates enter into transactions with certain AIG affiliates in the ordinary course of their conducting insurance and insurance-related activities, although no individual transaction is, and all such transactions collectively are not, material to our consolidated financial statements. We also conduct commodity risk management activities in the ordinary course of implementing our risk management strategies in which the counterparty to certain of our derivative transactions is an affiliate of Goldman Sachs. In conjunction with these activities, we are a party (through one of our subsidiaries engaged in the production of crude oil) to a hedging facility with J. Aron & Company/Goldman Sachs which requires us to provide certain periodic information, but does not require the posting of margin. As a result of changes in the market value of our derivative positions, we have created both amounts receivable from and payable to Goldman Sachs affiliates.

The following table summarizes the fair values of our energy commodity derivative contracts that are (i) associated with commodity price risk management activities with related parties; and (ii) included on our accompanying consolidated balance sheets as of June 30, 2009 and December 31, 2008 (in millions):

	June 30, 2009	December 31, 2008
Derivatives - asset/(liability)		
Other current assets	$ 0.6	$ 60.4
Deferred charges and other assets	14.5	20.1
Accrued other current liabilities	(44.5)	(13.2)
Other long-term liabilities and deferred credits	$ (142.1)	$ (24.1)

Other

Generally, KMR makes all decisions relating to the management and control of our business. Our general partner owns all of KMR's voting securities. KMI, through its wholly owned and controlled subsidiary Kinder Morgan (Delaware), Inc., owns all the common stock of our general partner. Certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, KMI and us; however, the audit committee of KMR's board of directors will, at the request of KMR, review (and is one of the means for resolving) conflicts of interest that may arise between KMI or its subsidiaries, on the one hand, and us, on the other hand. For a more complete discussion of our related-party transactions, see Note 12 to our consolidated financial statements included in our 2008 Form 10-K.

10. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during the six months ended June 30, 2009. Additional information with respect to these proceedings can be found in Note 16 to our audited financial statements that were filed with our 2008 Form 10-K. This note also contains a description of any material legal proceedings that were initiated against us during the six months ended June 30, 2009.

In this note, we refer to SFPP, L.P. as SFPP; Calnev Pipe Line LLC as Calnev; Chevron Products Company as Chevron; Navajo Refining Company, L.P. as Navajo; ARCO Products Company as ARCO; BP West Coast Products, LLC as BP WCP; Texaco Refining and Marketing Inc. as Texaco; Western Refining Company, L.P. as Western Refining; ExxonMobil Corporation as ExxonMobil; Tosco Corporation as Tosco; Ultramar Diamond Shamrock Corporation/Ultramar Inc. as Ultramar; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; America West Airlines, Inc., Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airline Complainants; the United States Court of Appeals for the District of Columbia Circuit as the D.C. Circuit; and the Federal Energy Regulatory Commission, as the FERC.

Federal Energy Regulatory Commission Proceedings

- FERC Docket No. OR92-8, et al.—Complainants/Protestants: Chevron, Navajo, ARCO, BP WCP, Western Refining, ExxonMobil, Tosco, and Texaco (Ultramar is an intervenor)—Defendant: SFPP; FERC Docket No. OR92-8-025—Complainants/Protestants: BP WCP; ExxonMobil; Chevron; ConocoPhillips; and Ultramar—Defendant: SFPP—Subject: Complaints against East Line and West Line rates and Watson Station Drain-Dry Charge;

- FERC Docket No. OR96-2, et al.—Complainants/Protestants: All Shippers except Chevron (which is an intervenor)—Defendant: SFPP—Subject: Complaints against all SFPP rates;

- FERC Docket Nos. OR02-4 and OR03-5—Complainant/Protestant: Chevron—Defendant: SFPP; FERC Docket No. OR04-3—Complainants/Protestants: America West Airlines, Southwest Airlines, Northwest Airlines, and Continental Airlines—Defendant: SFPP; FERC Docket Nos. OR03-5, OR05-4 and OR05-5—Complainants/Protestants: BP WCP, ExxonMobil, and ConocoPhillips (other shippers intervened)—Defendant:

SFPP—Subject: Complaints against all SFPP rates; OR02-4 was dismissed and Chevron appeal pending at the D.C. Circuit;

- FERC Docket Nos. OR07-1 & OR07-2—Complainant/Protestant: Tesoro—Defendant: SFPP—Subject: Complaints against North Line and West Line rates; held in abeyance;

- FERC Docket Nos. OR07-3 & OR07-6—Complainants/Protestants: BP WCP, Chevron, ConocoPhillips,ExxonMobil, Tesoro, and Valero Marketing—Defendant: SFPP—Subject: Complaints against 2005 and 2006 indexed rate increases; dismissed by FERC; appeal pending at D.C. Circuit;

- FERC Docket No. OR07-4—Complainants/Protestants: BP WCP, Chevron, and ExxonMobil—Defendants: SFPP, Kinder Morgan G.P., Inc., and KMI—Subject: Complaints against all SFPP rates; held in abeyance; complaint withdrawn as to SFPP's affiliates;

- FERC Docket Nos. OR07-5 and OR07-7 (consolidated) and IS06-296—Complainants/Protestants: ExxonMobil and Tesoro—Defendants: Calnev, Kinder Morgan G.P., Inc., and KMI—Subject: Complaints and protest against Calnev rates; OR07-5 and IS06-296 were settled in 2008; OR07-7 complaint amendment pending before FERC;

- FERC Docket Nos. OR07-18, OR07-19 & OR07-22—Complainants/Protestants: Airline Complainants, BP WCP, Chevron, ConocoPhillips and Valero Marketing—Defendant: Calnev—Subject: Complaints against Calnev rates; complaint amendments pending before FERC;

- FERC Docket No. OR07-20—Complainant/Protestant: BP WCP—Defendant: SFPP—Subject: Complaint against 2007 indexed rate increases; dismissed by FERC; appeal pending at D.C. Circuit;

- FERC Docket Nos. OR08-13 & OR08-15—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: SFPP—Subject: Complaints against all SFPP rates and 2008 indexed rate increases;

- FERC Docket No. IS05-230 (North Line rate case)—Complainants/Protestants: Shippers—Defendant: SFPP—Subject: SFPP filing to increase North Line rates to reflect expansion; initial decision issued; pending at FERC;

- FERC Docket No. IS07-137—Complainants/Protestants: Shippers—Defendant: SFPP—Subject: ULSD surcharge; settled;

- FERC Docket No. IS08-390—Complainants/Protestants: BP WCP, ExxonMobil, ConocoPhillips, Valero, Chevron, the Airline Complaintants—Defendant: SFPP—Subject: West Line rate increase; Initial Decision expected December 2009;

- FERC Docket No. IS09-375—Complainants/Protestants: BP, XOM, Chevron, Tesoro, ConocoPhillips, Western, Navajo, Valero, Southwest, and Airline Intervenors—Defendant: SFPP—Subject: Protests regarding 2009 indexed rate increases; protests dismissed by FERC;

- FERC Docket No. IS09-377—Complainants/Protestants: BP, Chevron, Tesoro, and Airline Intervenors—Defendant: Calnev—Subject: Protests regarding 2009 index-based rate increases; protests dismissed by FERC;

- FERC Docket No. OR09-8—Complainants/Protestants: Chevron—Defendant: SFPP—Subject: Complaint against 2008 index-based rate increases;

- FERC Docket No. OR09-11—Complainants/Protestants: BP WCP—Defendant: Calnev—Subject: Complaint requesting audit of Page 700 of FERC Form No. 6 for 2007 and 2008;

- FERC Docket No. OR09-12—Complainants/Protestants: BP WCP—Defendant: SFPP—Subject: Complaint requesting audit of Page 700 of FERC Form No. 6 for 2007 and 2008;

- FERC Docket No. OR09-14—Complainants/Protestants: Tesoro—Defendant: Calnev—Subject: Complaint requesting audit of Page 700 of FERC Form No. 6 for 2007 and 2008;

- FERC Docket No. OR09-15—Complainants/Protestants: Tesoro—Defendant: Calnev—Subject: Complaint against all Calnev rates;

- FERC Docket No. OR09-16—Complainants/Protestants: Tesoro—Defendant: SFPP—Subject: Complaint requesting audit of Page 700 of FERC Form No. 6 for 2007 and 2008;

and

- FERC Docket No. OR09-17—Complainants/Protestants: Tesoro—Defendant: SFPP—Subject: Complaint against SFPP rates.

The tariffs and rates charged by SFPP and Calnev are subject to numerous ongoing proceedings at the FERC, including the above listed shippers' complaints and protests regarding interstate rates on these pipeline systems. These complaints have been filed over numerous years beginning in 1992 through and including 2008. In general, these complaints allege the rates and tariffs charged by SFPP and Calnev are not just and reasonable. If the shippers are successful in proving their claims, they are entitled to seek reparations (which may reach up to two years prior to the filing of their complaint) or refunds of any excess rates paid, and SFPP and Calnev may be required to reduce their rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts.

As to SFPP, the issues involved in these proceedings include, among others: (i) whether certain of our Pacific operations' rates are "grandfathered" under the Energy Policy Act of 1992, and therefore deemed to be just and reasonable; (ii) whether "substantially changed circumstances" have occurred with respect to any grandfathered rates such that those rates could be challenged; (iii) whether indexed rate increases are justified; and (iv) the appropriate level of return and income tax allowance we may include in our rates. The issues involving Calnev are similar.

During 2008, SFPP and Calnev made combined settlement payments to various shippers totaling approximately $30.2 million in connection with OR92-8-025, IS06-283 and OR07-5. In October 2008, SFPP entered into a settlement resolving disputes regarding its East Line rates filed in Docket No. IS08-28 and related dockets. In January 2009, the FERC approved the settlement. Upon the finality of FERC's approval, reduced settlement rates became effective on May 1, 2009, and SFPP made refund and settlement payments totaling $15.5 million in May 2009.

Based on our review of these FERC proceedings, we estimate that as of June 30, 2009, shippers are seeking approximately $355 million in reparation and refund payments and approximately $30 to $35 million in additional annual rate reductions. We assume that, with respect to our SFPP litigation reserves, any reparations and accrued interest thereon will be paid no earlier than the fourth quarter of 2009.

California Public Utilities Commission Proceedings

SFPP has previously reported ratemaking proceedings pending with the California Public Utilities Commission, referred to in this note as the CPUC. The complaints generally challenge rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and request prospective rate adjustments and refunds with respect to previously untariffed charges for certain pipeline transportation and related services. All of these matters have been consolidated and assigned to a single administrative law judge. As of the filing of this report, it is unknown when a decision from the CPUC regarding these matters will be received. Based on our review of these CPUC proceedings, we estimate that shippers are seeking approximately $100 million in reparation and refund payments and approximately $35 million in annual rate reductions.

Carbon Dioxide Litigation

Gerald O. Bailey et al. v. Shell Oil Co. et al/Southern District of Texas Lawsuit

Kinder Morgan CO_2 Company, L.P., Kinder Morgan Energy Partners, L.P. and Cortez Pipeline Company are among the defendants in a proceeding in the federal courts for the Southern District of Texas. *Gerald O. Bailey et* *al. v. Shell Oil Company et al.* (Civil Action Nos. 05-1029 and 05-1829 in the U.S. District Court for the Southern District of Texas—consolidated by Order dated July 18, 2005). The plaintiffs are asserting claims for the underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit, located in southwestern Colorado. The plaintiffs assert claims for fraud/fraudulent inducement, real estate fraud, negligent misrepresentation, breach of fiduciary and agency duties, breach of contract and covenants, violation of the Colorado Unfair Practices Act, civil theft under Colorado law, conspiracy, unjust enrichment, and open account. Plaintiffs Gerald O. Bailey, Harry Ptasynski, and W.L. Gray & Co. have also asserted claims as private relators under the False Claims Act and for violation of federal and Colorado antitrust laws. The plaintiffs seek actual damages, treble damages, punitive damages, a constructive trust and accounting, and declaratory relief. The defendants filed motions for summary judgment on all claims.

On April 22, 2008, the federal district court granted defendants' motions for summary judgment and ruled that plaintiffs Bailey and Ptasynski, take nothing on their claims and that the claims of Gray be dismissed with prejudice. The court entered final judgment in favor of defendants on April 30, 2008. Defendants have filed a motion seeking sanctions against plaintiffs Bailey and Ptasynski and their attorney. The plaintiffs have appealed the final judgment to the United States Fifth Circuit Court of Appeals. The parties concluded their briefing to the Fifth Circuit Court of Appeals in February 2009.

CO_2 Claims Arbitration

Cortez Pipeline Company and Kinder Morgan CO_2, successor to Shell CO_2 Company, Ltd., were among the named defendants in CO_2 Committee, Inc. v. Shell Oil Co., et al., an arbitration initiated on November 28, 2005. The arbitration arose from a dispute over a class action settlement agreement which became final on July 7, 2003 and disposed of five lawsuits formerly pending in the U.S. District Court, District of Colorado. The plaintiffs in such lawsuits primarily included overriding royalty interest owners, royalty interest owners, and small share working interest owners who alleged underpayment of royalties and other payments on carbon dioxide produced from the McElmo Dome Unit.

The settlement imposed certain future obligations on the defendants in the underlying litigation. The plaintiffs alleged that, in calculating royalty and other payments, defendants used a transportation expense in excess of what is allowed by the settlement agreement, thereby causing alleged underpayments of approximately $12 million. The plaintiffs also alleged that Cortez Pipeline Company should have used certain funds to further reduce its debt, which, in turn, would have allegedly increased the value of royalty and other payments by approximately $0.5 million. On August 7, 2006, the arbitration panel issued its opinion finding that defendants did not breach the settlement agreement. On June 21, 2007, the New Mexico federal district court entered final judgment confirming the August 7, 2006 arbitration decision.

On October 2, 2007, the plaintiffs initiated a second arbitration (CO_2 Committee, Inc. v. Shell CO_2 Company, Ltd., aka Kinder Morgan CO_2 Company, L.P., et al.) against Cortez Pipeline Company, Kinder Morgan CO_2 and an ExxonMobil entity. The second arbitration asserts claims similar to those asserted in the first arbitration. On June 3, 2008, the plaintiffs filed a request with the American Arbitration Association seeking administration of the arbitration. In October 2008, the New Mexico federal district court entered an order declaring that the panel in the first arbitration should decide whether the claims in the second arbitration are barred by res judicata. The plaintiffs filed a motion for reconsideration of that order, which was denied by the New Mexico federal district court in January 2009. Plaintiffs have appealed to the Tenth Circuit Court of Appeals and continue to seek administration of the second arbitration by the American Arbitration Association. The American Arbitration Association has indicated that it intends to stay any action pending the Tenth Circuit appeal.

MMS Matters

The U.S. Department of the Interior, Minerals Management Service, referred to in this note as the MMS, and Kinder Morgan CO_2 have reached a settlement of the previously reported Notice of Noncompliance and Civil Penalty from December 2006 and Orders to Report and Pay from March 2007 and August 2007. The settlement agreement is subject to final MMS approval and upon approval will be funded from existing reserves and indemnity payments by Shell CO_2 General LLC and Shell CO_2 LLC pursuant to a royalty claim indemnification agreement.

J. Casper Heimann, Pecos Slope Royalty Trust and Rio Petro LTD, individually and on behalf of all other private royalty and overriding royalty owners in the Bravo Dome Carbon Dioxide Unit, New Mexico similarly situated v. Kinder Morgan CO_2 Company, L.P., No. 04-26-CL (8th Judicial District Court, Union County New Mexico)

This case involves a purported class action against Kinder Morgan CO_2 alleging that it has failed to pay the full royalty and overriding royalty, collectively referred to as the royalty interests, on the true and proper settlement value of compressed carbon dioxide produced from the Bravo Dome Unit during the period beginning January 1, 2000. The complaint purports to assert claims for violation of the New Mexico Unfair Practices Act, constructive fraud, breach of contract and of the covenant of good faith and fair dealing, breach of the implied covenant to market, and claims for an accounting, unjust enrichment, and injunctive relief. The purported class is comprised of current and former owners, during the period January 2000 to the present, who have private property royalty interests burdening the oil and gas leases held by the defendant, excluding the Commissioner of Public Lands, the United States of America, and those private royalty interests that are not unitized as part of the Bravo Dome Unit.

The case was tried to a jury in the trial court in September 2008. The plaintiffs sought $6.8 million in actual damages as well as punitive damages. The jury returned a verdict finding that Kinder Morgan CO_2 did not breach the settlement agreement and did not breach the claimed duty to market carbon dioxide. The jury also found that Kinder Morgan CO_2 breached a duty of good faith and fair dealing and found compensatory damages of $0.3 million and punitive damages of $1.2 million. On October 16, 2008, the trial court entered judgment on the verdict.

On January 6, 2009, the district court entered orders vacating the judgment and granting a new trial in the case. Kinder Morgan CO_2 filed a petition with the New Mexico Supreme Court, asking that court to authorize an immediate appeal of the new trial orders. In a 2 to 1 decision, the New Mexico Supreme Court denied Kinder Morgan CO_2's petition for immediate review of the new trial orders. The district court has scheduled a new trial to occur beginning on October 19, 2009.

Other

In addition to the matters listed above, audits and administrative inquiries concerning Kinder Morgan CO_2's payments on carbon dioxide produced from the McElmo Dome and Bravo Dome Units are currently ongoing. These audits and inquiries involve federal agencies, the states of Colorado and New Mexico, and county taxing authorities in the state of Colorado.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP and Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company and referred to in this note as UPRR) are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten year period beginning January 1, 2004 (*Union Pacific Railroad Company vs. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al.,* Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In February 2007, a trial began to determine the amount payable for easements on UPRR rights-of-way. The trial is ongoing and is expected to conclude by the end of 2009.

SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In July 2006, a trial before a judge regarding the circumstances under which SFPP must pay for relocations concluded, and the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP has appealed this decision, and in December 2008, the appellate court affirmed the decision. In addition, UPRR contends that SFPP must comply with the more expensive American Railway Engineering and Maintenance-of-Way standards in determining when relocations are necessary and in completing relocations. Each party is seeking declaratory relief with respect to its positions regarding the application of these standards with respect to relocations.

It is difficult to quantify the effects of the outcome of these cases on SFPP, because SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the expense (i.e., for railroad purposes, with the standards in the federal Pipeline Safety Act applying) would have an adverse effect on our financial position and results of operations. These effects would be even greater in the event SFPP is unsuccessful in one or more of these litigations.

United States of America, ex rel., Jack J. Grynberg v. K N Energy (Civil Action No. 97-D-1233, filed in the U.S. District Court, District of Colorado).

This multi-district litigation proceeding involves four lawsuits filed in 1997 against numerous Kinder Morgan companies. These suits were filed pursuant to the federal False Claims Act and allege underpayment of royalties due to mismeasurement of natural gas produced from federal and Indian lands. The complaints are part of a larger series of similar complaints filed by Mr. Grynberg against 77 natural gas pipelines (approximately 330 other defendants) in various courts throughout the country which were consolidated and transferred to the District of Wyoming.

In May 2005, a Special Master appointed in this litigation found that because there was a prior public disclosure of the allegations and that Grynberg was not an original source, the Court lacked subject matter jurisdiction. As a result, the Special Master recommended that the Court dismiss all the Kinder Morgan defendants. In October 2006, the United States District Court for the District of Wyoming upheld the dismissal of each case against the Kinder Morgan defendants on jurisdictional grounds. Grynberg appealed this Order to the Tenth Circuit Court of Appeals. Briefing was completed and oral argument was held on September 25, 2008. A decision by the Tenth Circuit Court of Appeals affirming the dismissal of the Kinder Morgan Defendants was issued on March 17, 2009. Grynberg's petition for rehearing was denied on May 4, 2009 and the Tenth Circuit issued its Mandate on May 18, 2009. A Petition for Writ of Certiorari, if filed, would be due August 3, 2009.

Prior to the dismissal order on jurisdictional grounds, the Kinder Morgan defendants filed Motions to Dismiss and for Sanctions alleging that Grynberg filed his Complaint without evidentiary support and for an improper purpose. On January 8, 2007, after the dismissal order, the Kinder Morgan defendants also filed a Motion for Attorney Fees under the False Claim Act. A decision is still pending on the Motions to Dismiss and for Sanctions and the Requests for Attorney Fees.

Severstal Sparrows Point Crane Collapse

On June 4, 2008, a bridge crane owned by Severstal Sparrows Point, LLC in Sparrows Point Maryland collapsed while being operated by Kinder Morgan Bulk Terminals, Inc. According to our investigation, the collapse was caused by unexpected, sudden and extreme winds. On June 24, 2009, Severstal filed suit against Kinder Morgan Bulk Terminals in the United States District Court for the District of Maryland, cause no. WMN 09CV1668, alleging that we were contractually obligated to replace the collapsed crane and that our employees were negligent in failing to properly secure the crane prior to the collapse. Severstal seeks unspecified damages for value of the crane and lost profits. Kinder Morgan Bulk Terminals denies each of Severstal's allegations.

Leukemia Cluster Litigation

Richard Jernee, et al v. Kinder Morgan Energy Partners, et al, No. CV03-03482 (Second Judicial District Court, State of Nevada, County of Washoe) ("Jernee").

Floyd Sands, et al v. Kinder Morgan Energy Partners, et al, No. CV03-05326 (Second Judicial District Court, State of Nevada, County of Washoe) ("Sands").

On May 30, 2003, plaintiffs, individually and on behalf of Adam Jernee, filed a civil action in the Nevada State trial court against us and several Kinder Morgan related entities and individuals and additional unrelated defendants. Plaintiffs in the Jernee matter claim that defendants negligently and intentionally failed to inspect, repair and replace unidentified segments of their pipeline and facilities, allowing "harmful substances and emissions and gases" to damage “the environment and health of human beings.” Plaintiffs claim that “Adam Jernee’s death was caused by leukemia that, in turn, is believed to be due to exposure to industrial chemicals and toxins.” Plaintiffs purport to assert claims for wrongful death, premises liability, negligence, negligence per se, intentional infliction of emotional distress, negligent infliction of emotional distress, assault and battery, nuisance, fraud, strict liability (ultra hazardous acts), and aiding and abetting, and seek unspecified special, general and punitive damages.

On August 28, 2003, a separate group of plaintiffs, represented by the counsel for the plaintiffs in the Jernee matter, individually and on behalf of Stephanie Suzanne Sands, filed a civil action in the Nevada State trial court against the same defendants and alleging the same claims as in the Jernee case with respect to Stephanie Suzanne Sands. The Jernee case has been consolidated for pretrial purposes with the Sands case.

In July, 2009, plaintiffs in both the Sands and Jernee cases agreed to dismiss all claims against the Kinder Morgan related defendants with prejudice in exchange for the Kinder Morgan defendants’ agreement that they would not seek to recover their defense costs against the plaintiffs. The Kinder Morgan defendants have filed a Motion for Approval of Good Faith Settlement with the trial court, which is currently pending. If granted, this matter will be concluded with respect to all Kinder Morgan related entities and individuals.

Pipeline Integrity and Releases

From time to time, despite our best efforts, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

Midcontinent Express Pipeline LLC Construction Incident

On July 15, 2009, a Midcontinent Express Pipeline LLC contractor and subcontractor were conducting a nitrogen pressure test on-facilities at a Midcontinent Express delivery meter station that was under construction-in Smith County, Mississippi. An unexpected release occurred during testing, resulting in one fatality and injuries to four other employees of the contractor or subcontractor. The United States Occupational Safety and Health Administration is investigating the cause of the incident with assistance from the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to in this note as the PHMSA. All construction work at other Midcontinent Express meter sites was allowed to continue after safety and construction reviews confirmed that the work could resume safely.

Pasadena Terminal Fire

On September 23, 2008, a fire occurred in the pit 3 manifold area of our Pasadena, Texas terminal facility. One of our employees was injured and subsequently died. In addition, the pit 3 manifold was severely damaged.

On July 13, 2009, a civil lawsuit was filed by and on behalf of the family of the deceased employee entitled *Brandy Williams et. al. v. KMGP Services Company, Inc.* in the 133rd District Court of Harris County, Texas, case no. 2009-44321. The suit alleges one count of gross negligence against defendant and seeks unspecified compensatory and punitive damages. We have filed an Answer denying the allegations in the Complaint, and the parties are currently engaged in discovery.

Rockies Express Pipeline LLC Wyoming Construction Incident

On November 11, 2006, a bulldozer operated by an employee of Associated Pipeline Contractors, Inc., a third-party contractor to Rockies Express Pipeline LLC, struck an existing subsurface natural gas pipeline owned by Wyoming Interstate Company, a subsidiary of El Paso Pipeline Group. The pipeline was ruptured, resulting in an explosion and fire. The incident occurred in a rural area approximately nine miles southwest of Cheyenne, Wyoming. The incident resulted in one fatality (the operator of the bulldozer) and there were no other reported injuries. The cause of the incident was investigated by the PHMSA. In March 2008, the PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order, referred to in this note as a NOPV, to El Paso Corporation in which it concluded that El Paso failed to comply with federal law and its internal policies and procedures regarding protection of its pipeline, resulting in this incident.

To date, the PHMSA has not issued any NOPV's to Rockies Express Pipeline LLC, referred to as Rockies Express, and we do not expect that it will do so. Immediately following the incident, Rockies Express and El Paso Pipeline Group reached an agreement on a set of additional enhanced safety protocols designed to prevent the reoccurrence of such an incident.

In September 2007, the family of the deceased bulldozer operator filed a wrongful death action against us, Rockies Express and several other parties in the District Court of Harris County, Texas, 189th Judicial District, at case number 2007-57916. The plaintiffs seek unspecified compensatory and exemplary damages plus interest, attorney's fees and costs of suit. We have asserted contractual claims for complete indemnification for any and all costs arising from this incident, including any costs related to this lawsuit, against third parties and their insurers. On March 25, 2008, we entered into a settlement agreement with one of the plaintiffs, the decedent's daughter, resolving any and all of her claims against us, Rockies Express and its contractors. We were indemnified for the full amount of this settlement by one of Rockies Express' contractors. On October 17, 2008, the remaining plaintiffs filed a Notice of Nonsuit, which dismissed the remaining claims against all defendants without prejudice to the plaintiffs' ability to re-file their claims at a later date. The remaining plaintiffs re-filed their Complaint against Rockies Express, us and several other parties on November 7, 2008, Cause No. 2008-66788, currently pending in the District Court of Harris County, Texas, 189th Judicial District. The parties are currently engaged in discovery.

Charlotte, North Carolina

On November 27, 2006, the Plantation Pipeline experienced a release of approximately 95 barrels of gasoline from a Plantation Pipe Line Company block valve on a delivery line into a terminal owned by a third party company. The line was repaired and put back into service within a few days. Remediation efforts are continuing under the direction of the North Carolina Department of Environment and Natural Resources, referred to in this note as the NCDENR, which issued a Notice of Violation and Recommendation of Enforcement against Plantation on January 8, 2007. Plantation continues to cooperate fully with the NCDENR.

In April 2007, during pipeline maintenance activities near Charlotte, North Carolina, Plantation discovered the presence of historical soil contamination near the pipeline, and reported the presence of impacted soils to the NCDENR. Subsequently, Plantation contacted the owner of the property to request access to the property to investigate the potential contamination. The results of that investigation indicate that there is soil and groundwater contamination which appears to be from a historical turbine fuel release. The groundwater contamination is underneath at least two lots on which there is current construction of single family homes that are part of a new residential development. Further investigation and remediation are being conducted under the oversight of the NCDENR. Plantation reached a settlement with the builder of the two homes that were impacted. Plantation continues to negotiate with the owner of the property to address any potential claims that it may bring.

Barstow, California

The United States Department of Navy has alleged that historic releases of methyl tertiary-butyl ether, referred to in this report as MTBE, from Calnev Pipe Line Company's Barstow terminal (i) have migrated underneath the Navy's Marine Corps Logistics Base in Barstow; (ii) have impacted the Navy's existing groundwater treatment system for unrelated groundwater contamination not alleged to have been caused by Calnev; and (iii) could affect the Barstow, California Marine Corps Logistic Base's water supply system. Although Calnev believes that it has certain meritorious defenses to the Navy's claims, it is working with the Navy to agree upon an Administrative Settlement Agreement and Order on Consent for federal Comprehensive Environmental Response, Compensation and Liability Act (referred to as CERCLA) Removal Action to reimburse the Navy for $0.5 million in past response actions, plus potentially perform other work, if the parties determine it to be necessary, to ensure protection of the Navy's existing treatment system and water supply.

Oil Spill Near Westridge Terminal, Burnaby, British Columbia

On July 24, 2007, a third-party contractor installing a sewer line for the City of Burnaby struck a crude oil pipeline segment included within our Trans Mountain pipeline system near its Westridge terminal in Burnaby, BC, resulting in a release of approximately 1,400 barrels of crude oil. The release impacted the surrounding neighborhood, several homes and nearby Burrard Inlet. No injuries were reported. To address the release, we initiated a comprehensive emergency response in collaboration with, among others, the City of Burnaby, the British Columbia Ministry of Environment, the National Energy Board, and the National Transportation Safety Board. Cleanup and environmental remediation is near completion.

The National Transportation Safety Board released its investigation report on the incident on March 18, 2009. The report confirmed that an absence of pipeline location marking in advance of excavation and inadequate communication between the contractor and our subsidiary Kinder Morgan Canada Inc., the operator of the line, were the primary causes of the accident. No directives, penalties or actions of Kinder Morgan Canada Inc. were required as a result of the report.

On July, 22, 2009, the British Columbia Ministry of Environment issued regulatory charges against the third-party contractor, the engineering consultant to the sewer line project, Kinder Morgan Canada Inc., and Trans Mountain L.P. (the last two of which are subsidiaries of ours). The charges claim that the parties charged caused the release of crude oil, and in doing so were in violation of various sections of the Environmental, Fisheries and Migratory Bird Acts. We are of the view that the charges have been improperly laid against us, and we intend to vigorously defend against them.

General

Although no assurance can be given, we believe that we have meritorious defenses to the actions set forth in this note and, to the extent an assessment of the matter is possible, if it is probable that a liability has been incurred and the amount of loss can be reasonably estimated, we believe that we have established an adequate reserve to cover potential liability.

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or cash flows. As of June 30, 2009 and December 31, 2008, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $207.9 million and $234.8 million, respectively. The reserve is primarily related to various claims from lawsuits arising from our West Coast products pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

The City of Los Angeles v. Kinder Morgan Liquids Terminals, LLC, Shell Oil Company, Equilon Enterprises LLC; California Superior Court, County of Los Angeles, Case No. NC041463.

Kinder Morgan Liquids Terminals LLC is a defendant in a lawsuit filed in 2005 alleging claims for environmental cleanup costs at the former Los Angeles Marine Terminal in the Port of Los Angeles. The lawsuit was stayed for the first half of 2009 in order to allow the parties to work with the regulatory agency concerning the scope of the required cleanup. The regulatory agency has not yet made any final decisions concerning cleanup of the former terminal, although the agency is expected to issue final cleanup orders in 2009.

The lawsuit stay has now been lifted, and two new defendants have been added to the lawsuit by plaintiff in a Third Amended Complaint. Plaintiff's Third Amended Complaint alleges that future environmental cleanup costs at the former terminal will exceed $10 million, and that Plaintiff's past damages exceed $2 million. No trial date has yet been set.

Exxon Mobil Corporation v. GATX Corporation, Kinder Morgan Liquids Terminals, LLC and ST Services, Inc.

On April 23, 2003, Exxon Mobil Corporation filed a complaint in the Superior Court of New Jersey, Gloucester County. The lawsuit relates to environmental remediation obligations at a Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corp. from 1989 through September 2000, later owned by Support Terminals. The terminal is now owned by Pacific Atlantic Terminals, LLC, and it too is a party to the lawsuit.

The complaint seeks any and all damages related to remediating all environmental contamination at the terminal, and, according to the New Jersey Spill Compensation and Control Act, treble damages may be available for actual dollars incorrectly spent by the successful party in the lawsuit. The parties are currently involved in mandatory mediation and met in June and October 2008. No progress was made at any of the mediations. The mediation judge has referred the case back to the litigation court room.

On June 25, 2007, the New Jersey Department of Environmental Protection, the Commissioner of the New Jersey Department of Environmental Protection and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint against ExxonMobil Corporation and Kinder Morgan Liquids Terminals LLC, f/k/a GATX Terminals Corporation. The complaint was filed in Gloucester County, New Jersey. Both ExxonMobil and KMLT filed third party complaints against Support Terminals seeking to bring Support Terminals into the case. Support Terminals filed motions to dismiss the third party complaints, which were denied. Support Terminals is now joined in the case and it filed an Answer denying all claims.

The plaintiffs seek the costs and damages that the plaintiffs allegedly have incurred or will incur as a result of the discharge of pollutants and hazardous substances at the Paulsboro, New Jersey facility. The costs and damages that the plaintiffs seek include cleanup costs and damages to natural resources. In addition, the plaintiffs seek an order compelling the defendants to perform or fund the assessment and restoration of those natural resource damages that are the result of the defendants' actions. As in the case brought by ExxonMobil against GATX Terminals, the issue is whether the plaintiffs' claims are within the scope of the indemnity obligations between GATX Terminals (and therefore, Kinder Morgan Liquids Terminals) and Support Terminals. The court may consolidate the two cases. The parties are now conducting discovery.

State of Texas v. Kinder Morgan Petcoke, L.P.

Harris County, Texas Criminal Court No. 11, Cause No. 1571148 On February 24, 2009, our subsidiary Kinder Morgan Petcoke, L.P. was served with a misdemeanor summons alleging the unintentional discharge of petroleum coke into the Houston Ship Channel during maintenance activities. On May 27, 2009, we settled the matter by entering a plea of nolo contendere to one count of unintentional discharge to water and paying a fine of $30,000.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the state of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and MTBE impacted soils and groundwater beneath the city's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County, case number 37-2007-00073033-CU-OR-CTL. On September 26, 2007, we removed the case to the United States District Court, Southern District of California, case number 07CV1883WCAB. On October 3, 2007, we filed a Motion to Dismiss all counts of the Complaint. The court denied in part and granted in part the Motion to Dismiss and gave the City leave to amend their complaint. The City submitted its Amended Complaint and we filed an Answer. The parties have commenced with discovery. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board.

Kinder Morgan Port Manatee Terminal, LLC, Palmetto, Florida

On June 18, 2009, Kinder Morgan Port Manatee Terminal received a Revised Warning Letter from the Florida Department of Environmental Protection, referred to in this note as the Florida DEP, advising us of possible regulatory and air permit violations regarding operations at the Port Manatee Terminal. We previously conducted a voluntary internal audit at this facility in March 2008 and identified various environmental compliance and permitting issues primarily related to air quality compliance. We reported our findings from this audit in a self-disclosure letter to the Florida DEP in March, 2008. Following the submittal of our self-disclosure letter, the agency conducted numerous inspections of the air pollution control devices at the Terminal and issued this Revised Warning Letter. We have scheduled a meeting with the Florida DEP to attempt to resolve these issues.

In addition, we have received a subpoena from the U.S. Department of Justice for production of documents related to the service and operation of the Kinder Morgan Port Manatee Terminal. We are fully cooperating with the investigation of this matter.

Other Environmental

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and carbon dioxide field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving alleged air, water and waste violations issued by various governmental authorities related to compliance with environmental regulations. As we receive notices of non-compliance, we negotiate and settle these matters. We do not believe that these alleged violations will have a material adverse effect on our business.

We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs issued by various regulatory authorities related to compliance with environmental regulations associated with our assets. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, natural gas liquids, natural gas and carbon dioxide. See "—Pipeline Integrity and Releases" above for additional information with respect to ruptures and leaks from our pipelines.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur and changing circumstances could cause these matters to have a material adverse impact. As of June 30, 2009, we have accrued an environmental reserve of $78.1 million, and we believe the establishment of this environmental reserve is adequate such that the resolution of pending environmental matters will not have a material adverse impact on our business, cash flows, financial position or results of operations. In addition, we have recorded a receivable of $18.6 million for expected cost recoveries that have been deemed probable. As of December 31, 2008, our environmental reserve totaled $78.9 million and our estimated receivable for environmental cost recoveries totaled $20.7 million, respectively. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

Other

We are a defendant in various lawsuits arising from the day-to-day operations of our businesses. Although no assurance can be given, we believe, based on our experiences to date, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

11. Regulatory Matters

The following updates the disclosure in Note 17 to our audited financial statements that were filed with our 2008 Form 10-K, with respect to developments that occurred during the six months ended June 30, 2009.

Notice of Proposed Rulemaking – Natural Gas Price Transparency

On November 20, 2008, the FERC issued Order 720, which established new reporting requirements for interstate and major non-interstate natural gas pipelines. Interstate pipelines are required to post no-notice activity at each receipt and delivery point three days after the day of gas flow. Major non-interstate pipelines are required to post design capacity, scheduled volumes and available capacity at each receipt or delivery point with a design capacity of 15,000 MMBtus of natural gas per day or greater. The final rule became effective January 27, 2009 for interstate pipelines. On January 15, 2009, the FERC issued an order granting an extension of time for major non-interstate pipelines to comply until 150 days following the issuance of an order addressing the pending requests for rehearing. On January 16, 2009, the FERC granted rehearing of Order 720. On July 16, 2009, the FERC issued a request for supplemental comments on revisions to the posting requirements. Comments are due on October 31, 2009. We do not expect this Order to have a material impact on our consolidated financial statements.

Notice of Proposed Rulemaking - Contract Reporting Requirements of Intrastate Natural Gas Companies, Docket No. RM09-2-000.

On November 20, 2008, the FERC issued a Notice of Inquiry seeking comments on whether the FERC should require intrastate and Hinshaw pipelines to publicly report the details of their transactions in interstate commerce. Comments were filed on February 13, 2009. In response to such comments, on July 16, 2009, the FERC issued a Notice of Proposed Rulemaking in this proceeding, proposing to revise the existing annual transactional reporting requirements for intrastate and Hinshaw pipelines to be filed on a quarterly basis and to include more information than was required under the annual reports. Comments are due on October 27, 2009.

Natural Gas Pipeline Expansion Filings

Rockies Express Meeker to Cheyenne Expansion Project

Pursuant to certain rights exercised by EnCana Gas Marketing USA as a result of its foundation shipper status on the former Entrega Gas Pipeline LLC facilities (now part of the Rockies Express Pipeline), Rockies Express Pipeline LLC is requesting authorization to construct and operate certain facilities that will comprise its Meeker, Colorado to Cheyenne, Wyoming Rockies Express Pipeline expansion project. The proposed expansion will add natural gas compression at its Big Hole compressor station located in Moffat County, Colorado, and its Arlington compressor station located in Carbon County, Wyoming. Upon completion, the additional compression will permit the transportation of an additional 200 million cubic feet per day of natural gas from (i) the Meeker Hub located in Rio Blanco County, Colorado northward to the Wamsutter Hub located in Sweetwater County, Wyoming; and (ii) the Wamsutter Hub eastward to the Cheyenne Hub located in Weld County, Colorado.

The expansion is fully contracted and is expected to be operational in April 2010. The total estimated cost for the proposed project is approximately $78 million. By Commission order issued July 16, 2009 Rockies Express was granted authorization to construct and operate this project.

Rockies Express Pipeline-East Project

Construction continued during the second quarter of 2009 on the previously announced Rockies Express Pipeline-East Pipeline project. The Rockies Express-East project includes the construction of an additional natural gas pipeline segment, comprising approximately 639 miles of 42-inch diameter pipeline commencing from the terminus of the Rockies Express-West pipeline to a terminus near the town of Clarington in Monroe County, Ohio. Current market conditions for consumables, labor and construction equipment along with certain provisions in the final regulatory orders have resulted in increased costs for the project and have impacted certain projected completion dates. On October 31, 2008, Rockies Express filed an amendment to its certificate application, seeking authorization to revise its tariff-based recourse rates for transportation service on the Rockies Express-East pipeline segment to reflect updated construction costs for the project. By order issued March 16, 2009, the FERC authorized the revised rates as filed by Rockies Express. Including expansions, our current estimate of total construction costs on the entire Rockies Express Pipeline is now approximately $6.7 billion (consistent with our July 15, 2009 second quarter earnings press release).

On June 29, 2009, Rockies Express-East commenced service on the portion of the pipeline from Audrain County, Missouri to the Lebanon Hub in Warren County, Ohio. This section of the line provides capacity of approximately 1.6 billion cubic feet per day of natural gas, and includes interconnects to Natural Gas Pipeline Company of America LLC, Ameren, Trunkline, Midwestern Gas Transmission, Panhandle Eastern, Texas Eastern, Dominion Transmission and Columbia Gas, with future interconnects to Texas Gas Transmission, ANR, Citizens and Vectren. The remainder of Rockies Express-East, consisting of approximately 195-miles of 42-inch diameter pipe extending to Clarington, Ohio, is expected to be in service by November 1, 2009. When completed, the entire 1,679-mile Rockies Express Pipeline will have a capacity of approximately 1.8 billion cubic feet per day of natural gas, virtually all of which has been contracted under long-term firm commitments from creditworthy shippers.

Kinder Morgan Interstate Gas Transmission Pipeline - Huntsman 2009 Expansion Project

Our Kinder Morgan Interstate Gas Transmission natural gas pipeline system, referred to as KMIGT, has filed an application with the FERC for authorization to construct and operate certain storage facilities necessary to increase the storage capability of the existing Huntsman Storage Facility, located near Sidney, Nebraska. KMIGT also requested approval of new incremental rates for the project facilities under its currently effective Cheyenne Market Center Service Rate Schedule CMC-2. When fully constructed, the proposed facilities will create incremental firm storage capacity for up to one million dekatherms of natural gas, with an associated injection capability of approximately 6,400 dekatherms per day and an associated deliverability of approximately 10,400 dekatherms per day. As a result of an open season, KMIGT and one shipper have executed a firm precedent agreement for 100% of the capacity to be created by the project facilities over a five-year term.

Kinder Morgan Louisiana Pipeline

On December 30, 2008, we filed a second amendment to our certificate application, seeking authorization to revise our initial rates for transportation service on our previously announced Kinder Morgan Louisiana natural gas pipeline system to reflect additional increases in estimated construction costs for the project (a first amendment revising our initial rates was filed in July 2008 and accepted by the FERC in August 2008). The filing was approved by the FERC on February 27, 2009. On April 16, 2009, we received authorization from the FERC to begin service on Leg 2 of the approximately 133-mile, 42-inch diameter pipeline, and service on Leg 2 commenced April 18, 2009. On June 21, 2009, we completed pipeline construction and placed the pipeline system's remaining portion into service. The Kinder Morgan Louisiana Pipeline project cost approximately $1 billion to complete (consistent with our July 15, 2009 second quarter earnings press release).

The Kinder Morgan Louisiana Pipeline provides approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal, located in Cameron Parish, Louisiana, to various delivery points in Louisiana. The pipeline interconnects with multiple third-party pipelines and all of the capacity on the pipeline system has been fully subscribed by Chevron and Total under 20-year take-or-pay customer commitments. One transportation contract became effective on June 21, 2009, and the second will become effective in the third quarter of 2009.

Midcontinent Express Pipeline

Construction continued during the second quarter of 2009 on the previously announced Midcontinent Express Pipeline project. The Midcontinent Express Pipeline is owned by Midcontinent Express Pipeline LLC, a 50/50 joint venture between us and Energy Transfer Partners, L.P. The pipeline will extend from southeast Oklahoma, across northeast Texas, northern Louisiana and central Mississippi, and terminate at an interconnection with the Transco Pipeline near Butler, Alabama. The entire estimated project cost for the approximately 500-mile natural gas pipeline system is expected to be approximately $2.3 billion (consistent with our July 15, 2009 second quarter earnings press release).

On January 9, 2009, Midcontinent Express filed an amendment to its original certificate application requesting authorization to revise its initial rates for transportation service on the pipeline system to reflect an increase in projected construction costs for the project. The filing was approved by the FERC on March 25, 2009. Interim service commenced for Zone 1 on April 10, 2009 with deliveries to Natural Gas Pipeline Company of America LLC. Service to all Zone 1 delivery points occurred by May 21, 2009. Zone 2 is anticipated to be placed in service on or about August 1, 2009.

Fayetteville Express Pipeline

Pipeline system development work continued during the second quarter of 2009 on the previously announced Fayetteville Express Pipeline project. The Fayetteville Express Pipeline is owned by Fayetteville Express Pipeline LLC, another 50/50 joint venture between us and Energy Transfer Partners, L.P. The Fayetteville Express Pipeline is a 187-mile, 42-inch diameter natural gas pipeline that will begin in Conway County, Arkansas, and end in Panola County, Mississippi. The pipeline will have an initial capacity of two billion cubic feet per day, and has currently secured ten year binding commitments totaling 1.85 billion cubic feet per day of capacity. On June 15, 2009, Fayetteville Express filed its certificate application with the FERC. Pending regulatory approvals, the pipeline is expected to be in service by late 2010 or early 2011. Our estimate of the total costs of this pipeline project is approximately $1.2 billion (consistent with our July 15, 2009 second quarter earnings press release).

12. Recent Accounting Pronouncements

SFAS No. 141(R) and FASB Staff Position No. 141(R)-1

On December 4, 2007, the FASB issued SFAS No. 141R (revised 2007), "Business Combinations." Although this statement amends and replaces SFAS No. 141, it retains the fundamental requirements in SFAS No. 141 that (i) the purchase method of accounting be used for all business combinations; and (ii) an acquirer be identified for each business combination. This Statement applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree), including combinations achieved without the transfer of consideration; however, this Statement does not apply to a combination between entities or businesses under common control.

Significant provisions of SFAS No. 141R concern principles and requirements for how an acquirer (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement was adopted by us effective January 1, 2009, and the adoption of this Statement did not have a material impact on our consolidated financial statements.

On April 1, 2009, the FASB issued FASB Staff Position No. FAS 141(R)-1, "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." This Staff Position amends the provisions related to the initial recognition and measurement, subsequent measurement and disclosure of assets and liabilities arising from contingencies in a business combination under SFAS No. 141R. This Staff Position carries forward the requirements in SFAS No. 141, "Business Combinations," for acquired contingencies, which would require that such contingencies be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the allocation period. Otherwise, companies would typically account for the acquired contingencies in accordance with SFAS No. 5, "Accounting for Contingencies." This Staff Position has the same effective date as SFAS No. 141R, and did not have a material impact on our consolidated financial statements.

SFAS No. 160

On December 4, 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51." This Statement changes the accounting and reporting for noncontrolling interests, sometimes referred to as minority interests, in consolidated financial statements. A noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. We adopted SFAS No. 160 effective January 1, 2009.

Specifically, SFAS No. 160 establishes accounting and reporting standards that require (i) the ownership interests in subsidiaries held by parties other than the parent to be clearly identified, labeled, and presented in the consolidated balance sheet within equity, but separate from the parent's equity; and (ii) the equity amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated income statement. Accordingly, our consolidated net income and comprehensive income are now determined without deducting amounts attributable to our noncontrolling interests, but our earnings-per-unit information continues to be calculated on the basis of the net income attributable to our limited partners. The provisions of this Statement apply prospectively; however, the presentation and disclosure requirements are applied retrospectively for all periods presented.

SFAS No. 161

On March 19, 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities." This Statement amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and provides for enhanced disclosure requirements that include, among other things, (i) a tabular summary of the fair value of derivative instruments and their gains and losses; (ii) disclosure of derivative features that are credit-risk–related to provide more information regarding an entity's liquidity; and (iii) cross-referencing within footnotes to make it easier for financial statement users to locate important information about derivative instruments. This Statement was adopted by us effective January 1, 2009, and the adoption of this Statement did not have a material impact on our consolidated financial statements.

EITF 07-4

In March 2008, the Emerging Issues Task Force reached a consensus on Issue No. 07-4, or EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships." EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. For us, this Issue was effective January 1, 2009. The guidance in this Issue is to be applied retrospectively for all financial statements presented; however, the adoption of this Issue did not have any impact on our consolidated financial statements.

FASB Staff Position No. FAS 142-3

On April 25, 2008, the FASB issued FASB Staff Position No. FAS 142-3 "Determination of the Useful Life of Intangible Assets." This Staff Position amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, "Goodwill and Other Intangible Assets." For us, this Staff Position was effective January 1, 2009, and the adoption of this Staff Position did not have any impact on our consolidated financial statements.

FASB Staff Position No. EITF 03-6-1

On June 16, 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." This Staff Position clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the calculation of basic earnings per share. For us, this Staff Position was effective January 1, 2009, and the adoption of this Staff Position did not have any impact on our consolidated financial statements.

FASB Staff Position No. FAS 157-3

On October 10, 2008, the FASB issued FASB Staff Position No. FAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for that Asset is Not Active." This Staff Position provides guidance clarifying how SFAS No. 157, "Fair Value Measurements," should be applied when valuing securities in markets that are not active. This Staff Position applies the objectives and framework of SFAS No. 157 to determine the fair value of a financial asset in a market that is not active, and it reaffirms the notion of fair value as an exit price as of the measurement date. Among other things, the guidance also states that significant judgment is required in valuing financial assets. This Staff Position became effective upon issuance, and did not have any material effect on our consolidated financial statements.

EITF 08-6

On November 24, 2008, the FASB ratified the consensus reached by the Emerging Issues Task Force on Issue No. 08-6, or EITF 08-6, "Equity Method Investment Accounting Considerations." EITF 08-6 clarifies certain accounting and impairment considerations involving equity method investments. For us, this Issue was effective January 1, 2009, and the adoption of this Issue did not have any impact on our consolidated financial statements.

FASB Staff Position No. FAS 132(R)-1

On December 30, 2008, the FASB issued FASB Staff Position No. FAS 132(R)-1, "Employer's Disclosures About Postretirement Benefit Plan Assets." This Staff Position is effective for financial statements ending after December 15, 2009 (December 31, 2009 for us) and requires additional disclosure of pension and post retirement benefit plan assets regarding (i) investment asset classes; (ii) fair value measurement of assets; (iii) investment strategies; (iv) asset risk; and (v) rate-of-return assumptions. We do not expect this Staff Position to have a material impact on our consolidated financial statements.

Securities and Exchange Commission's Final Rule on Oil and Gas Disclosure Requirements

On December 31, 2008, the Securities and Exchange Commission issued its final rule "Modernization of Oil and Gas Reporting," which revises the disclosures required by oil and gas companies. The SEC disclosure requirements for oil and gas companies have been updated to include expanded disclosure for oil and gas activities, and certain definitions have also been changed that will impact the determination of oil and gas reserve quantities. The provisions of this final rule are effective for registration statements filed on or after January 1, 2010, and for annual reports for fiscal years ending on or after December 31, 2009. We are currently reviewing the effects of this final rule.

FASB Staff Position No. FAS 157-4
FASB Staff Position No. FAS 107-1 and APB 28-1
FASB Staff Position No. FAS 115-2 and FAS 124-2

On April 9, 2009, the FASB issued three separate Staff Positions intended to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157, "Fair Value Measurements." This Staff Position provides additional guidance to highlight and expand on the factors that should be considered in estimating fair value when there has been a significant decrease in market activity for a financial asset.

FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments," enhances consistency in financial reporting by increasing the frequency of fair value disclosures from annual only to quarterly, in order to provide financial statement users with more timely information about the effects of current market conditions on their financial instruments. This Staff Position requires us to disclose in our interim financial statements the fair value of all financial instruments within the scope of SFAS No. 107, “Disclosures about Fair Value of Financial Instruments,” as well as the method(s) and significant assumptions we use to estimate the fair value of those financial instruments.

FAS 115-2 and FAS 124-2, “Recognition and Presentation of Other-Than-Temporary Impairments,” provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. This Staff Position changes (i) the method for determining whether an other-than-temporary impairment exists for debt securities; and (ii) the amount of an impairment charge to be recorded in earnings.

For us, each of these three Staff Positions became effective June 30, 2009; however, the adoption of these Staff Positions did not have a material impact on our consolidated financial statements.

SFAS No. 165

On May 28, 2009, the FASB issued SFAS No. 165, “Subsequent Events.” This Statement establishes general standards of accounting for and disclosure of subsequent events—events or transactions that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. This Statement was effective for interim and annual periods ending after June 15, 2009. For us, this Statement became effective June 30, 2009, and the adoption of this Statement did not have a material impact on our consolidated financial statements. For more information on our disclosure of subsequent events, see Note 1.

SFAS Nos. 166 and 167

On June 12, 2009, the FASB published SFAS No. 166, “Accounting for Transfers of Financial Assets—an amendment of FASB Statement No. 140,” and SFAS No. 167, “Amendments to FASB Interpretation No. 46(R)." The Statements change the way entities account for securitizations and special-purpose entities. SFAS No. 166 is a revision of SFAS No. 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,” and will require more information about transfers of financial assets, including securitization transactions, and where companies have continuing exposure to the risks related to transferred financial assets. SFAS No. 167 is a revision to FASB Interpretation No. 46(R), “Consolidation of Variable Interest Entities,” and changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated.

Both Statement Nos. 166 and 167 will be effective at the start of an entity’s first fiscal year beginning after November 15, 2009 (January 1, 2010 for us). We do not expect the adoption of these Statements to have a material impact on our consolidated financial statements.

SFAS No. 168 and the Financial Accounting Standards Board’s Accounting Standards Codification

On June 3, 2009, the FASB voted to approve its Accounting Standards Codification as the single source of authoritative nongovernmental U.S. generally accepted accounting principles, commonly referred to as GAAP, effective July 1, 2009. The move was officially effected by the June 29, 2009 issuance of SFAS No. 168, “The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles—a replacement of SFAS No. 162.” On the effective date of this Statement, the Codification will supersede all then-existing non-Securities and Exchange Commission accounting and reporting standards. All other nongrandfathered non-Securities and Exchange Commission accounting literature not included in the Codification will become nonauthoritative. In other words, the GAAP hierarchy will be modified to include only two levels of GAAP: authoritative and nonauthoritative.

While the Codification does not change U.S. GAAP, it introduces a new structure—reorganizing the thousands of pre-Codification U.S. GAAP pronouncements into approximately 90 accounting topics and displaying all topics consistently. Rules and interpretive releases of the U.S. Securities and Exchange Commission under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants, and the Codification includes relevant SEC guidance that follows the same topical structure in separate sections. All guidance contained in the Codification carries an equal level of authority.

The Codification will be effective for interim and annual periods ending after September 15, 2009 (September 30, 2009 for us). The adoption of the Accounting Standards Codification will affect the way we reference U.S. GAAP in our financial statements and in our accounting policies; however, we do not expect the adoption to have any direct effect on our consolidated financial statements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

General and Basis of Presentation

The following information should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes (included elsewhere in this report); and (ii) our consolidated financial statements, related notes and management's discussion and analysis of financial condition and results of operations included in our 2008 Form 10-K.

In addition, our financial statements and the financial information contained in this Management's Discussion and Analysis of Financial Condition and Results of Operations reflect the August 28, 2008 transfer of both the 33 1/3% interest in the Express and Platte crude oil pipeline system net assets (collectively referred to in this report as the Express pipeline system) and the Jet Fuel pipeline system net assets from KMI as of the date of transfer. Accordingly, we have included the financial results of the Express and Jet Fuel pipeline systems within our Kinder Morgan Canada business segment disclosures presented in this report for all periods subsequent to August 28, 2008.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of generally accepted accounting principles involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates.

Further information about us and information regarding our accounting policies and estimates that we consider to be "critical" can be found in our 2008 Form 10-K. There have not been any significant changes in these policies and estimates during the three months ended June 30, 2009.

Results of Operations

Consolidated

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Earnings Increase/(decrease)	
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)	(In millions, except percentages)			
Products Pipelines(b)	$ 155.0	$ 137.6	$ 17.4	13%
Natural Gas Pipelines(c)	162.1	182.5	(20.4)	(11)%
CO_2	202.7	216.6	(13.9)	(6)%
Terminals(d)	142.9	140.4	2.5	2%
Kinder Morgan Canada(e)	46.7	33.4	13.3	40%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	709.4	710.5	(1.1)	—
Depreciation, depletion and amortization expense	(203.1)	(165.6)	(37.5)	(23)%
Amortization of excess cost of equity investments	(1.5)	(1.5)	—	—
General and administrative expense(f)	(72.6)	(72.8)	0.2	—
Unallocable interest expense, net of interest income(g)	(101.3)	(99.9)	(1.4)	(1)%
Unallocable income tax expense	(2.3)	(4.4)	2.1	48%
Net income	328.6	366.3	(37.7)	(10)%
Net income attributable to noncontrolling interests	(4.8)	(4.1)	(0.7)	(17)%
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 323.8	$ 362.2	$ (38.4)	(11)%

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	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Earnings Increase/(decrease)	
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)	(In millions, except percentages)			
Products Pipelines(h)	$ 300.4	$ 278.3	$ 22.1	8%
Natural Gas Pipelines(i)	362.9	370.7	(7.8)	(2)%
CO_2	370.1	416.4	(46.3)	(11)%
Terminals(j)	277.6	266.2	11.4	4%
Kinder Morgan Canada(k)	66.2	63.6	2.6	4%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	1,377.2	1,395.2	(18.0)	(1)%
Depreciation, depletion and amortization expense	(413.3)	(323.7)	(89.6)	(28)%
Amortization of excess cost of equity investments	(2.9)	(2.9)	—	—
General and administrative expense(l)	(155.1)	(149.6)	(5.5)	(4)%
Unallocable interest expense, net of interest income(m)	(205.9)	(197.6)	(8.3)	(4)%
Unallocable income tax expense	(4.6)	(4.4)	(0.2)	(5)%
Net income	595.4	717.0	(121.6)	(17)%
Net income attributable to noncontrolling interests(n)	(7.7)	(8.1)	0.4	5%
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 587.7	$ 708.9	$ (121.2)	(17)%

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(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other expense (income). Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, fuel and power expenses, and taxes, other than income taxes.

(b) 2009 and 2008 amounts include increases in income of $1.0 million and $0.1 million, respectively, resulting from unrealized foreign currency gains on long-term debt transactions. 2009 amount also includes a $3.8 million increase in expense associated with environmental liability adjustments. 2008 amount also includes a $0.8 million gain from the 2007 sale of our North System.

(c) 2009 and 2008 amounts include decreases in income of $2.5 million and $13.1 million, respectively, resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas. 2008 amount also includes a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC.

(d) 2009 amount includes a $0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal, and a $0.1 million increase in expense associated with environmental liability adjustments.
(e) 2009 amount includes a $3.7 million decrease in expense due to a certain non-cash accounting change related to book tax accruals and foreign exchange fluctuations.
(f) Includes unallocated litigation and environmental expenses. 2009 and 2008 amounts include increases of $1.4 million in non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses). 2009 amount also includes a $0.9 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.
(g) 2009 and 2008 amounts include increases in imputed interest expense of $0.3 million and $0.5 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.
(h) 2009 and 2008 amounts include a $0.4 million increase in income and a $0.7 million decrease in income, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions. 2009 amount also includes a $3.8 million increase in expense associated with environmental liability adjustments. 2008 amount also includes a $1.3 million gain from the 2007 sale of our North System.
(i) 2009 and 2008 amounts include decreases in income of $3.8 million and $13.1 million, respectively, resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas. 2008 amount also includes a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC.
(j) 2009 amount includes a $0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal, and a $0.1 million increase in expense associated with environmental liability adjustments.
(k) 2009 amount includes a $3.7 million decrease in expense due to a certain non-cash accounting change related to book tax accruals and foreign exchange fluctuations, and a $14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to the carrying amount of the previously established deferred tax liability.
(l) 2009 and 2008 amounts include increases of $2.8 million in non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses). 2009 amount also includes a $0.1 million increase in expense for certain Express pipeline system acquisition costs, and a $1.5 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.
(m) 2009 and 2008 amounts include increases in imputed interest expense of $0.8 million and $1.0 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.
(n) 2009 amount includes a $0.2 million decrease in net income attributable to noncontrolling (minority) interests, related to all of the six month 2009 items previously disclosed in these footnotes.

For the quarterly period ended June 30, 2009, net income attributable to our partners, which includes all of our limited partner unitholders and our general partner, totaled $323.8 million in the second quarter of 2009, compared to $362.2 million for the quarterly period ended June 30, 2008. Our total revenues for the comparative second quarter periods were $1,645.3 million in 2009 and $3,495.7 million in 2008. For the six months ended June 30, 2009 and 2008, net income attributable to our partners totaled $587.7 million and $708.9 million, respectively, on revenues of $3,431.8 million and $6,216.0 million, respectively.

Because our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash as defined in our partnership agreement generally consists of all our cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments, to be an important measure of our success in maximizing returns to our partners. We also use segment earnings before depreciation, depletion and amortization expenses (defined in the table above and sometimes referred to in this report as EBDA) internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our five reportable business segments.

Total segment earnings before depreciation, depletion and amortization for the three months ended June 30, 2009 was essentially flat versus the same quarter last year. Combined, the certain items described in the footnotes to the tables above decreased total segment EBDA by $2.0 million (combining to decrease total segment EBDA by $1.2 million in 2009 and to increase total segment EBDA by $0.8 million in 2008). The remaining $0.9 million increase in total segment EBDA included higher earnings in 2009 from our Products Pipelines, Kinder Morgan Canada and Terminals business segments, and lower earnings from our Natural Gas Pipelines and CO_2 business segments.

For the comparable six month periods, the certain items described in the footnotes to the tables decreased segment EBDA by $18.5 million in 2009, when compared to the first half of last year (combining to decrease total segment EBDA by $18.0 million in 2009 and to increase total segment EBDA by $0.5 million in 2008). The remaining $0.5 million increase in total segment EBDA was driven by better performance from our Products

Pipelines, Kinder Morgan Canada and Terminals business segments, and offset by lower year-over-year earnings from our CO_2 and Natural Gas Pipelines business segments.

Products Pipelines

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In millions, except operating statistics)			
Revenues	$ 206.7	$ 198.6	$ 394.9	$ 396.9
Operating expenses(a)	(60.0)	(68.5)	(109.0)	(130.9)
Other income (expense)(b)	—	0.6	—	1.0
Earnings from equity investments	8.0	8.7	13.4	16.2
Interest income and Other, net-income (expense)(c)	3.5	1.3	6.3	1.8
Income tax benefit (expense)	(3.2)	(3.1)	(5.2)	(6.7)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 155.0	$ 137.6	$ 300.4	$ 278.3
Gasoline (MMBbl)	104.2	100.5	199.8	198.4
Diesel fuel (MMBbl)	36.5	41.6	72.0	80.2
Jet fuel (MMBbl)	28.1	29.9	54.9	59.6
Total refined product volumes (MMBbl)	168.8	172.0	326.7	338.2
Natural gas liquids (MMBbl)	7.3	6.1	12.2	13.0
Total delivery volumes (MMBbl)(d)	176.1	178.1	338.9	351.2

(a) 2009 amounts include a $3.8 million increase in expense associated with environmental liability adjustments. 2008 amounts include a $3.0 million decrease in expense to our Pacific operations and a $3.0 million increase in expense to our Calnev Pipeline associated with legal liability adjustments.

(b) Three and six month 2008 amounts include gains of $0.8 million and $1.3 million, respectively, from the 2007 sale of our North System. We accounted for the North System business as a discontinued operation; however, because the sale does not change the structure of our internal organization in a manner that causes a change to our reportable business segments, we included the 2008 gain adjustments within our Products Pipelines business segment disclosures. Except for these gain adjustments on disposal of the North System, we recorded no other financial results from the operations of the North System during the first six months of 2008.

(c) Three and six month 2009 amounts include increases in income of $1.0 million and $0.4 million, respectively, resulting from unrealized foreign currency gains on long-term debt transactions. Three and six month 2008 amounts include an increase in income of $0.1 million and a decrease in income of $0.7 million, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions.

(d) Includes Pacific, Plantation, Calnev, Central Florida, Cochin and Cypress pipeline volumes.

Combined, the certain items described in the footnotes to the table above decreased our Product Pipelines' earnings before depreciation, depletion and amortization expenses by $3.7 million in the second quarter of 2009, and decreased earnings before depreciation, depletion and amortization expenses by $4.0 million in the first six months of 2009, when compared to same periods in 2008. For each of the comparable three and six month periods, following is information related to (i) the remaining increases and decreases in segment earnings before depreciation, depletion and amortization expenses (EBDA); and (ii) the increases and decreases in operating revenues:

Three months ended June 30, 2009 versus Three months ended June 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline System	$ 7.8	128%	$ 6.2	58%
Pacific operations	4.8	8%	1.4	2%
West Coast Terminals	3.6	29%	4.0	22%
Central Florida Pipeline	2.6	24%	3.0	22%
Plantation Pipeline	(0.1)	(1)%	(6.1)	(56)%
All others (including eliminations)	2.4	7%	(0.4)	(1)%
Total Products Pipelines	$ 21.1	15%	$ 8.1	4%

Six months ended June 30, 2009 versus Six months ended June 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
West Coast Terminals	$ 9.2	39%	$ 8.6	24%
Cochin Pipeline System	8.9	54%	2.5	10%
Central Florida Pipeline	5.1	24%	6.1	24%
Pacific operations	3.7	3%	(3.5)	(2)%
Plantation Pipeline	(2.1)	(9)%	(12.2)	(55)%
All others (including eliminations)	1.3	2%	(3.5)	(4)%
Total Products Pipelines	$ 26.1	9%	$ (2.0)	(1)%

Overall, our Products Pipelines business segment reported strong operating results in the second quarter of 2009 as earnings before depreciation, depletion and amortization expenses increased $21.1 million (15%), when compared to the second quarter of 2008. Although ongoing weak economic conditions continued to dampen demand for refined petroleum products at many of our assets in this segment, resulting in lower volumes versus the second quarter of 2008, earnings were positively impacted by higher operating revenues, due to increased natural gas liquids throughput volumes on the Cochin pipeline system, by higher ethanol revenues on our Central Florida Pipeline, and by improved warehousing margins at existing and expanded West Coast terminal facilities. In addition, the segment benefited from a $12.3 million (18%) reduction in combined operating expenses in the second quarter of 2009, primarily due to lower outside services and other discretionary operating expenses, lower fuel and power expenses, and due to new service contracts or bidding work at lower prices compared to a year earlier.

The primary increase in segment earnings for the comparable three month periods was attributable to the $7.8 million (128%) increase from our Cochin Pipeline. The increase in earnings from Cochin was largely related to the $6.2 million (58%) increase in operating revenues compared to the same quarter a year earlier. The increase in revenues was driven by a 42% increase in liquids throughput volumes, reflecting increased pipeline utilization that was mainly due to significantly higher throughput volumes on the pipelines’ East Leg (which services Windsor, Ontario, Canada, and extends to Sarnia, Ontario).

The period-to-period earnings increases from our West Coast terminal operations were largely revenue related, driven by higher revenues from our combined Carson/Los Angeles Harbor terminal system and by incremental returns from the completion of a number of capital expansion projects that modified and upgraded terminal infrastructure since the end of the second quarter of 2008. Revenues at our Carson/Los Angeles terminal complex increased $3.0 million and $6.5 million in the second quarter and first six months of 2009, respectively, when compared to the same periods a year earlier. The increases were mainly due to both increased warehouse charges (escalated warehousing contract rates resulting from customer contract revisions made since the second quarter a year ago) and to new customers (including incremental terminalling for U.S. defense fuel services). Revenues from our remaining West Coast facilities increased $1.0 million and $2.1 million in the second quarter and first six months of 2009, respectively, due mostly to additional throughput and storage services associated with renewable fuels (both ethanol and biodiesel).

Earnings before depreciation, depletion and amortization from our Pacific operations increased $4.8 million (8%) in the second quarter of 2009, when compared to the second quarter last year. The increase in earnings was due mainly to a $3.2 million (10%) decrease in combined operating expenses and a $1.4 million (2%) increase in total revenues. The decrease in expenses, relative to 2008, was due to both higher product gains and lower right-of-way and environmental expenses. The increase in revenues included a $1.1 million (2%) increase in mainline delivery revenues, driven by a nearly 4% increase in average tariff rates.

The earnings increases from our Central Florida Pipeline were mainly due to both incremental ethanol revenues, resulting from capital expansion projects that provided ethanol storage and terminal service beginning in mid-April 2008 at our Tampa and Orlando terminals, and from higher overall revenues driven by higher average transportation rates, due to a mid-year tariff rate increase that became effective July 1, 2008.

Earnings from our approximate 51% equity investment in the Plantation Pipe Line Company were essentially flat across both second quarter periods, but decreased $2.1 million (9%) in the first half of 2009, when compared to the same period last year. The six month decrease in earnings from our investment in Plantation was chiefly attributable to lower oil loss allowance revenues in 2009. The drop in oil loss allowance revenues, relative to last year, reflects the decline in refined product market prices since the end of the second quarter of 2008. The overall decreases in revenues earned from our investment in Plantation in both the comparable three and six month periods were mainly due to changes made to the Plantation operating agreement by ExxonMobil and us. On January 1, 2009, both parties agreed to reduce the fixed operating fees we earn from operating the pipeline; however, the reductions in our fee revenues were largely offset by corresponding decreases in the labor and non-labor expenses we incurred from operating the pipeline—resulting in minimal impact on our net operating income in the first six months of 2009.

Also, on June 30, 2009, Plantation successfully completed the first U.S. transmarket commercial shipment of blended 5% biodiesel on a mainline segment of its pipeline. In addition to the June 2009 deliveries to marketing terminals located in Athens, Georgia and Roanoke, Virginia, Plantation is optimistically moving forward to delivering biodiesel to multiple markets along its pipeline system in response to customers' needs for blending and transporting biodiesel to meet federal regulatory requirements.

Combining all of the segment's operations, total revenues from refined petroleum products deliveries increased 0.4% in the second quarter of 2009, when compared to the second quarter of 2008; however, total products delivery volumes decreased 1.9% as ongoing weak economic conditions resulted in lower demand for diesel and jet fuel. Total gasoline delivery volumes increased 3.7% (including ethanol), diesel volumes decreased 12.3%, and jet fuel volumes decreased 6.0%, respectively, in the second quarter of 2009 compared to the second quarter of 2008. Excluding Plantation—which is impacted by a competing pipeline—total refined products delivery revenues were up 3.5% and total refined product delivery volumes were down 2.2%, when compared to the second quarter last year.

Gasoline delivery volumes (including ethanol) increased 0.7% in the first half of 2009, when compared to the first half of 2008, due to higher second quarter 2009 volumes. Year-over-year percentage changes in jet fuel volumes showed some improvement in the second quarter of 2009, when compared to the prior quarter (first quarter of 2009), while year-over-year percentage changes in diesel volumes further declined in the second quarter of 2009 versus the prior quarter. Natural gas liquids delivery volumes on our Cochin and Cypress pipelines increased by 20% in the second quarter of 2009 compared to the second quarter last year, chiefly due to the 42% increase in liquids deliveries on the Cochin Pipeline (discussed above).

Natural Gas Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions, except operating statistics)			
Revenues	$ 860.7	$ 2,644.7	$ 1,912.4	$ 4,557.2
Operating expenses(a)	(739.3)	(2,515.6)	(1,629.8)	(4,260.7)
Other income	—	2.7	—	2.7
Earnings from equity investments	29.4	31.3	56.0	54.8
Interest income and Other, net-income (expense)(b)	12.6	17.7	27.3	17.9
Income tax benefit (expense)	(1.3)	1.7	(3.0)	(1.2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 162.1	$ 182.5	$ 362.9	$ 370.7
Natural gas transport volumes (Trillion Btus)(c)	541.8	502.3	1,050.2	983.2
Natural gas sales volumes (Trillion Btus)(d)	198.1	224.9	401.8	440.0

(a) Three and six month 2009 amounts include decreases in income of $2.5 million and $3.8 million, respectively, and 2008 amounts include decreases in income of $13.1 million, all resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas.

(b) 2008 amounts include a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC.
(c) Includes Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC, TransColorado Gas Transmission Company LLC, Rockies Express Pipeline LLC, Midcontinent Express Pipeline LLC, Kinder Morgan Louisiana Pipeline and Texas intrastate natural gas pipeline group pipeline volumes.
(d) Represents Texas intrastate natural gas pipeline group volumes.

For the three and six months ended June 30, 2009, the certain items related to our Natural Gas Pipelines business segment and described in the footnotes to the table above decreased the change in earnings before depreciation, depletion and amortization expenses by $2.4 million and $3.7 million, respectively. For each of the comparable three and six month periods of 2009 and 2008, following is information related to (i) the remaining changes in segment earnings before depreciation, depletion and amortization expenses (EBDA); and (ii) the changes in operating revenues:

Three months ended June 30, 2009 versus Three months ended June 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Texas Intrastate Natural Gas Pipeline Group	$ (26.4)	(29)%	$(1,751.4)	(69)%
Rockies Express Pipeline	(2.5)	(10)%	—	—
Kinder Morgan Louisiana Pipeline	7.3	242%	—	—
Kinder Morgan Interstate Gas Transmission	5.2	19%	(5.9)	(12)%
All others (including eliminations)	(1.6)	(5)%	(26.7)	(37)%
Total Natural Gas Pipelines	$ (18.0)	(10)%	$(1,784.0)	(67)%

Six months ended June 30, 2009 versus Six months ended June 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Texas Intrastate Natural Gas Pipeline Group	$ (28.3)	(14)%	$(2,592.6)	(60)%
Kinder Morgan Louisiana Pipeline	15.9	525%	—	—
Kinder Morgan Interstate Gas Transmission	9.5	17%	(4.5)	(5)%
Rockies Express Pipeline	2.3	6%	—	—
All others (including eliminations)	(3.5)	(5)%	(47.7)	(35)%
Total Natural Gas Pipelines	$ (4.1)	(1)%	$(2,644.8)	(58)%

The overall decreases in segment earnings before depreciation, depletion and amortization expenses in 2009 for the comparable three and six month periods were driven primarily by lower earnings from our Texas intrastate natural gas pipeline group. The decreases in earnings from the intrastate group were mainly attributable to lower margins from natural gas sales, timing differences that negatively affected both natural gas storage margins and operational expenses, relative to last year, and lower natural gas processing margins, due to unfavorable gross processing spreads as a result of significantly lower average natural gas liquids prices in 2009.

Combined, the decreases in natural gas sales margins on our two largest intrastate pipeline systems—Kinder Morgan Tejas (including Kinder Morgan Border Pipeline) and Kinder Morgan Texas Pipeline—totaled $14.8 million and $21.4 million, respectively, in the three and six month periods of 2009, when compared to the same periods last year. The decreases in sales margins were primarily due to lower average natural gas prices and partly due to lower pipeline spreads and lower sales volumes, relative to 2008. Compared to the same periods in 2008, total natural gas sales volumes for our intrastate group decreased 12% and 9% in the three and six month periods of 2009, respectively, primarily due to the economic slow-down and to natural gas production declines.

The incremental earnings before depreciation, depletion and amortization expenses from our Kinder Morgan Louisiana Pipeline, which began full service on June 21, 2009, primarily relates to other non-operating income realized in the second quarter and first six months of 2009 pursuant to FERC regulations governing allowances for capital funds that are used for pipeline construction costs (an equity cost of capital allowance). The equity cost of capital allowance provides for a reasonable return on construction costs that are funded by equity contributions, similar to the allowance for capital costs funded by borrowings. In addition to the start of service on our Kinder

Morgan Louisiana Pipeline, interim service on our 50% owned Midcontinent Express Pipeline commenced on April 10, 2009, with deliveries to Natural Gas Pipeline Company of America LLC. Service to all Zone 1 delivery points occurred by May 21, 2009.

The increases in earnings from our Kinder Morgan Interstate Gas Transmission pipeline system reflect higher period-to-period operating margins, driven mainly by higher firm transportation demand fees, higher earnings from natural gas park and loan services, and higher pipeline fuel recoveries, relative to the same comparable periods a year ago. The increase in demand fees was mainly due to the completion of (i) our previously announced Colorado Lateral expansion project in November 2008; and (ii) additional system expansions completed since the end of the second quarter of 2008 that provide for delivery service to multiple ethanol-producing industrial plants.

The increases and decreases in earnings from our equity investment in the Rockies Express joint venture pipeline relate to changes in net income earned by Rockies Express Pipeline LLC. Lower equity earnings in the second quarter of 2009, relative to last year, was chiefly due to Rockies Express' higher interest expenses, due to higher year-over-year average borrowings, and partly due to higher depreciation and property tax expenses, as a result of more assets in service during the first half of 2009. Higher equity earnings for the full six months of 2009 were primarily due to incremental earnings attributable to the Rockies Express-West natural gas pipeline segment, which began full operations in May 2008. Overall transport volumes for the entire Rockies Express Pipeline increased 7% in the second quarter of 2009, and 26% in the first half of 2009, when compared to the same periods last year, and these volume increases were mainly due to the full operations of Rockies Express-West. Additionally, initial pipeline service on the Rockies Express-East pipeline segment began on June 29, 2009. The Rockies Express-East line extends from Audrain County, Missouri to the Lebanon Hub in Warren County, Ohio and currently has a total capacity of up to 1.6 billion cubic feet per day.

CO_2

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions, except operating statistics)			
Revenues	$ 258.2	$ 308.6	$ 487.1	$ 595.0
Operating expenses	(59.3)	(96.6)	(125.9)	(187.3)
Earnings from equity investments	5.1	5.5	10.9	11.1
Other, net-income (expense)	—	—	—	(0.2)
Income tax benefit (expense)	(1.3)	(0.9)	(2.0)	(2.2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 202.7	$ 216.6	$ 370.1	$ 416.4
Carbon dioxide delivery volumes (Bcf)(a)	188.7	178.6	401.4	358.8
SACROC oil production (gross)(MBbl/d)(b)	31.1	27.5	30.6	27.4
SACROC oil production (net)(MBbl/d)(c)	25.9	22.9	25.5	22.8
Yates oil production (gross)(MBbl/d)(b)	26.8	28.1	26.6	28.3
Yates oil production (net)(MBbl/d)(c)	11.9	12.5	11.8	12.6
Natural gas liquids sales volumes (net)(MBbl/d)(c)	9.6	9.1	9.2	9.3
Realized weighted average oil price per Bbl(d)(e)	$ 49.47	$ 53.01	$ 46.71	$ 51.52
Realized weighted average natural gas liquids price per Bbl(e)(f)	$ 34.02	$ 77.28	$ 31.20	$ 71.48

(a) Includes Cortez, Central Basin, Canyon Reef Carriers, Centerline and Pecos pipeline volumes.
(b) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit and an approximately 50% working interest in the Yates unit.
(c) Net to Kinder Morgan, after royalties and outside working interests.
(d) Includes all Kinder Morgan crude oil production properties.
(e) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.
(f) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our CO_2 segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) and crude oil, and the production and marketing of natural gas and natural gas liquids. For each of the segment's two primary businesses, following is information related to the increases and decreases, in the comparable three and six month periods of 2009 and 2008, of the segment's (i) earnings before depreciation, depletion and amortization (EBDA); and (ii) operating revenues:

Three months ended June 30, 2009 versus Three months ended June 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ (23.1)	(32)%	$ (19.8)	(25)%
Oil and Gas Producing Activities	9.2	6%	(41.6)	(17)%
Intrasegment Eliminations	—	—	11.0	55%
Total CO_2	$ (13.9)	(6)%	$ (50.4)	(16)%

Six months ended June 30, 2009 versus Six months ended June 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ (29.9)	(21)%	$ (25.8)	(17)%
Oil and Gas Producing Activities	(16.4)	(6)%	(96.7)	(20)%
Intrasegment Eliminations	—	—	14.6	39%
Total CO_2	$ (46.3)	(11)%	$ (107.9)	(18)%

The segment's overall decreases in earnings before depreciation, depletion and amortization expenses in the comparable three and six month periods of 2009 versus 2008 were primarily due to lower earnings from the segment's sales and transportation activities. The period-to-period decreases in earnings from sales and transportation activities were primarily due to decreases in carbon dioxide sales revenues, and partly due to decreases in pipeline transportation revenues.

Overall revenues from carbon dioxide sales to third parties decreased $16.0 million (30%) and $17.0 million (17%), respectively, in the second quarter and first half of 2009, when compared to the same prior year periods, and the decreases were entirely price related, as the segment's average price received for all carbon dioxide sales decreased 39% and 31%, respectively, in the three and six month periods ended June 30, 2009, when compared to last year. The decreases in average sales prices in 2009 were due primarily to a portion of our carbon dioxide sales contracts being tied to lower crude oil prices, when compared to prior year periods.

The period-to-period decreases in sales revenues due to the drop in prices were partially offset, however, by increases in carbon dioxide sales volumes in the comparable three and six month periods of 2009 versus 2008. Primarily due to expansion projects completed since the end of the second quarter last year, and also to a continued strong demand for carbon dioxide use in and around the Permian Basin, our carbon dioxide sales volumes increased 16% and 21%, respectively, in the three and six month periods of 2009, when compared to the same periods a year ago. For both comparable periods, carbon dioxide delivery volumes also increased 6% and 12%, respectively, due largely to completed expansion projects that increased carbon dioxide production in southwest Colorado. We do not recognize profits on carbon dioxide sales to ourselves.

Earnings from the segment's oil and gas producing activities, which include the operations associated with its ownership interests in oil-producing fields and natural gas processing plants, increased $9.2 million (6%) in the second quarter of 2009, but decreased $16.4 million (6%) in the first half of 2009, when compared to the same periods last year. Generally, earnings from the segment's oil and gas producing activities are closely aligned with the revenues earned from both crude oil and natural gas plant products sales, and although oil and gas related revenues decreased $41.6 million (17%) in the second quarter of 2009, relative to the second quarter last year, oil and gas related operating expenses decreased by $50.8 million (48%). The decrease in revenues was due to lower average sales prices in the second quarter of 2009 for both crude oil and natural gas liquids (although the decrease from lower prices was somewhat offset by increased volumes), and the decrease in combined operating expenses was due in part to overall cost reduction efforts (discussed below) and in part to a $15.4 million favorable adjustment to our accrued severance tax liabilities due to prior year overpayments.

The decrease in earnings from oil and gas producing activities in the comparable six month periods was driven by lower sales revenues from both crude oil and natural gas liquids, due largely to lower crude oil and natural gas liquids realizations in the first half of 2009, compared to last year (although average industry price levels for crude oil have increased since the beginning of 2009). Compared to the first half of 2008, revenues from crude oil sales decreased $17.6 million (5%) and revenues from natural gas liquids sales decreased $68.5 million (57%), respectively. The overall decrease in oil and gas related earnings in the comparable six month periods was partially offset by an $80.3 million (39%) decrease in combined operating expenses in the first half of 2009. The decrease in expenses was mostly related to lower severance and property tax expenses (including the June 2009 severance tax adjustment discussed above), lower operating, maintenance and fuel and power expenses (due in part to lower prices charged by the industry's material and service providers), and to the successful renewal of lower priced service and supply contracts negotiated by our CO_2 segment since the beginning of 2009.

Because price levels of crude oil and natural gas liquids are subject to external factors over which we have no control, and because future price changes may be volatile, our CO_2 segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids. To some extent, we are able to mitigate this commodity price risk through a long-term hedging strategy that is intended to generate more stable realized prices by using derivative contracts to hedge the majority of our long-term production. The derivatives hedge our exposure to fluctuating future cash flows produced by changes in commodity sales prices; nonetheless, decreases in the prices of crude oil and natural gas liquids will have a negative impact on the result of our CO_2 business segment, and even though we hedge the majority of our crude oil production, we do have exposure to unhedged volumes, the majority of which are natural gas liquids volumes.

With respect to crude oil, our realized weighted average price per barrel decreased 7% and 9% in the second quarter and first six months of 2009, respectively, when compared to the same periods a year ago. The decreases in revenues due to unfavorable pricing were partially offset by increases of 7% and 5%, respectively, in crude oil sales volumes. Average gross oil production for the second quarter of 2009 was 31.1 thousand barrels per day at the SACROC unit, 13% higher compared to the second quarter of 2008. At Yates, average gross oil production for the second quarter of 2009 was 26.8 thousand barrels per day, a decline of almost 5% versus the same quarter last year, but up slightly (1%) compared to the first quarter of 2009.

With respect to natural gas liquids, for the three and six month periods of 2009, our realized weighted average price per barrel decreased 56% in both comparable periods, and sales volumes increased 6% in the second quarter of 2009, but remained flat in the first half of 2009 versus the first half of 2008. All of our hedge gains and losses for crude oil and natural gas liquids are included in our realized average price for oil, and had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $56.98 per barrel in the second quarter of 2009, and $123.03 per barrel in the second quarter of 2008. For more information on our hedging activities, see Note 6 to our consolidated financial statements included elsewhere in this report.

Terminals

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In millions, except operating statistics)			
Revenues	$ 264.0	$ 300.7	$ 531.9	$ 580.9
Operating expenses(a)	(123.9)	(156.0)	(257.5)	(308.8)
Other income (expense)	2.7	(0.2)	3.6	0.4
Earnings from equity investments	—	0.7	0.1	1.7
Interest income and Other, net-income (expense)	1.2	1.4	1.1	2.7
Income tax expense	(1.1)	(6.2)	(1.6)	(10.7)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 142.9	$ 140.4	$ 277.6	$ 266.2
Bulk transload tonnage (MMtons)(b)	18.2	27.7	36.9	51.6
Liquids leaseable capacity (MMBbl)	55.1	52.4	55.1	52.4
Liquids utilization %	96.9%	98.1%	96.9%	98.1%

(a) 2009 amounts include a $0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal, and a $0.1 million increase in expense associated with environmental liability adjustments.

(b) Volumes for acquired terminals are included for all periods.

Our Terminals business segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment), and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities. We group our bulk and liquids terminal operations into regions based on geographic location and/or primary operating function. This structure allows our management to organize and evaluate segment performance and to help make operating decisions and allocate resources.

The segment's operating results in the first six months of 2009 include incremental contributions from strategic terminal acquisitions. Beginning with our June 16, 2008 acquisition of a steel terminal located in Cincinnati, Ohio, we have invested approximately $38.1 million in cash to acquire various terminal assets and operations, and combined, our acquired terminal operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $1.5 million, revenues of $4.9 million, and operating expenses of $3.4 million in the second quarter of 2009. For the six month period of 2009, acquired assets contributed incremental earnings before depreciation, depletion and amortization of $2.4 million, revenues of $7.3 million, and operating expenses of $4.9 million. All of the incremental amounts listed above represent the earnings, revenues and expenses from acquired terminals' operations during the additional months of ownership in 2009, and do not include increases or decreases during the same months we owned the assets in 2008.

For all other terminal operations (those owned during identical periods in both 2009 and 2008), the certain items described in footnote (a) to the table above increased earnings before depreciation, depletion and amortization expenses for the three and six months ended June 30, 2009 by $0.4 million, when compared to the same two periods last year. Following is information for these terminal operations, for each of the comparable three and six month periods and by terminal operating region, related to (i) the remaining $0.6 million (0%) and $8.6 million (3%) increases in earnings before depreciation, depletion and amortization; and (ii) the $41.6 million (14%) and $56.3 million (10%) decreases in operating revenues:

Three months ended June 30, 2009 versus Three months ended June 30, 2008

	EBDA Increase/(decrease)		Revenues Increase/(decrease)	
	(In millions, except percentages)			
Lower River (Louisiana)	$ 8.2	149%	$ (3.9)	(14)%
Gulf Coast	1.8	5%	(0.4)	(1)%
West	1.2	12%	(2.1)	(10)%
Mid River	(5.0)	(57)%	(13.1)	(53)%
Ohio Valley	(3.7)	(53)%	(6.9)	(38)%
Mid-Atlantic	(2.5)	(21)%	(8.2)	(28)%
All others (including eliminations)	0.6	1%	(7.0)	(5)%
Total Terminals	$ 0.6	—	$ (41.6)	(14)%

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Six months ended June 30, 2009 versus Six months ended June 30, 2008

	EBDA Increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Lower River (Louisiana)	$ 11.5	85%	$ (6.8)	(13)%
Northeast	3.6	10%	4.7	8%
Texas Petcoke	3.1	10%	(2.3)	(4)%
Gulf Coast	3.0	4%	2.2	2%
Mid River	(7.9)	(52)%	(22.1)	(47)%
Ohio Valley	(4.6)	(43)%	(9.9)	(32)%
All others (including eliminations)	(0.1)	—	(22.1)	(9)%
Total Terminals	$ 8.6	3%	$ (56.3)	(10)%

Earnings before depreciation, depletion and amortization from terminals owned in both comparable periods was flat for the second quarter of 2009 and up 3% in the first six months of the year, versus the same periods of 2008. The increases in earnings before depreciation, depletion and amortization expenses from our Lower River (Louisiana) terminals were mainly due to the higher earnings realized in the second quarter of 2009, relative to the second quarter last year. The increase was driven by both a $4.4 million increase in earnings from our International Marine Terminals facility, a Louisiana partnership located in Port Sulphur, Louisiana and owned 66 2/3% by us, and a $3.6 million decrease in income tax expense due to lower taxable income in our tax paying terminal subsidiaries. Although quarterly revenues at IMT declined by $3.0 million in the second quarter of 2009, due to less tonnage and lower revenues from fleeting and barge services, the terminal benefited from both a $4.2 million decrease in operating expenses, due to lower fuel and power expenses and lower crane rental and ship demurrage fees, and from a $3.2 million property casualty gain (on a vessel dock that was damaged in June 2009).

The increases in earnings from our Gulf Coast terminals were driven by favorable results from our Pasadena and Galena Park, Texas liquids facilities located along the Houston Ship Channel. The increases were driven by higher liquids warehousing revenues, mainly due to new and incremental customer agreements (at higher rates) and to additional ancillary terminal services. For our Terminals segment combined, expansion projects completed since the second quarter of 2008 increased our liquids terminals' leasable capacity to 55.1 million barrels, up 5% from a capacity of 52.4 million barrels at the end of the second quarter of 2008. At the same time, our overall liquids utilization capacity rate (the ratio of our actual leased capacity to our estimated potential capacity) decreased a slight 1% since the end of the second quarter of 2008.

The increase in earnings in the second quarter of 2009 from our West region terminals was driven by an incremental contribution of $1.4 million from our Kinder Morgan North 40 terminal, the crude oil tank farm we constructed near Edmonton, Alberta, Canada, and which was placed into service in the second quarter of 2008. Earnings from our Northeast terminals, which include the combined operations of our three New York Harbor liquids terminals, and our Texas Petcoke terminals, which primarily handle petroleum coke tonnage in and around the Texas Gulf Coast, were flat for the second quarter of 2009, but higher in 2009 on a year-to-date basis (as discussed below).

The increase in earnings in the first half of 2009 versus the first half of 2008 from our New York Harbor terminals, which include our Perth Amboy, New Jersey terminal, our Carteret, New Jersey terminal, and our Staten Island, New York terminal, was driven by a 7% increase in combined liquids throughput volumes, resulting from both terminal expansions completed since the second quarter of 2008 and continued strong demand for petroleum distillates. The increase in earnings through the first six months of 2009 from our petroleum coke operations was driven by higher petroleum coke throughput volumes and higher handling rates, relative to the first half of 2008, at our Port of Houston and Port Arthur, Texas terminal locations.

The overall increases in segment earnings before depreciation, depletion and amortization in the comparable three and six month periods of 2009 versus 2008 were partly offset by lower earnings from our Mid River and Ohio Valley terminals, and in the comparable second quarter periods only, by lower earnings from our Mid-Atlantic terminals. The decreases from these facilities were due primarily to decreased import/export activity, and to lower business activity at various owned and/or operated rail and terminal sites that are primarily involved in the handling and storage of steel and alloy products.

The economic downturn that began last year has negatively affected the worldwide steel industry and has led to a general decrease in U.S. port activity relative to the first half of last year. As a result, for our Terminals segment combined, bulk traffic tonnage decreased by 9.5 million tons (34%) in the second quarter of 2009, and decreased 14.7 million tons (28%) in the first six months of 2009, when compared to the same prior year periods. The economic downturn and drops in tonnage resulted in lower period-to-period revenues and earnings at various terminal facilities that handle steel and iron ore, dock barges and deep sea vessels for bulk cargo operations, and perform stevedoring and wharfage services.

Kinder Morgan Canada

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions, except operating statistics)			
Revenues	$ 56.0	$ 43.4	$ 106.0	$ 86.5
Operating expenses	(18.1)	(17.0)	(33.3)	(32.7)
Earnings from equity investments	(0.6)	—	(0.3)	0.1
Interest income and Other, net-income (expense)	8.2	4.0	8.9	6.1
Income tax benefit (expense)(a)	1.2	3.0	(15.1)	3.6
Earnings (loss) before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 46.7	$ 33.4	$ 66.2	$ 63.6
Transport volumes (MMBbl)(b)	24.3	21.5	46.9	40.9

(a) 2009 amounts include a $3.7 million decrease in expense due to a certain non-cash accounting change related to book tax accruals and foreign exchange fluctuations related to the Express pipeline system. Six month 2009 amount also includes a $14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to Trans Mountain's carrying amount of the previously established deferred tax liability.

(b) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of the Trans Mountain, Express, and Jet Fuel pipeline systems. We acquired both our one-third equity ownership interest in the approximate 1,700-mile Express pipeline system and our full ownership of the approximate 25-mile Jet Fuel pipeline system from KMI effective August 28, 2008. After taking into account the certain item related to the Express pipeline system described in footnote (a) to the table above, these combined businesses accounted for incremental amounts of earnings before depreciation, depletion and amortization of $2.6 million and $6.6 million in the second quarter and first half of 2009, respectively. The incremental earnings primarily related to interest earned on our long-term investment in a debt security issued by the Express pipeline.

After taking into effect the residual non-cash certain items described in footnote (a) to the table above and the Express acquisition described above, the segment's remaining business—the Trans Mountain crude oil and refined products pipeline system—contributed incremental earnings before depreciation, depletion and amortization expenses of $7.0 million (21%) and $7.2 million (11%) in the second quarter and first six months of 2009, respectively. The increases in earnings were driven by higher pipeline transportation revenues, due to increases in pipeline throughput volumes and to higher tariff rates that became effective in May 2009.

In the second quarter and first half of 2009, Trans Mountain's operating revenues increased $11.8 million (27%) and $18.0 million (21%), respectively, when compared to the same periods last year. The increases in revenues were driven by corresponding increases in mainline delivery volumes—13% in the comparable three month periods and 15% in the comparable six month periods—resulting primarily from expansion projects completed since the second quarter of 2008, and from increases in ship traffic during 2009 at the Port of Metro Vancouver. On both April 28 and October 30 of 2008, we completed separate portions of the Trans Mountain Pipeline's Anchor Loop expansion project and combined, this project boosted pipeline transportation capacity by 15% (from 260,000 barrels per day to 300,000 barrels per day) and resulted in higher period-to-period average toll rates.

Other

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(a)	$ (72.6)	$ (72.8)	$ 0.2	—
Unallocable interest expense, net of interest income(b)	$ (101.3)	$ (99.9)	$ (1.4)	(1)%
Unallocable income tax expense	$ (2.3)	$ (4.4)	$ 2.1	48%
Net income attributable to noncontrolling interests	$ (4.8)	$ (4.1)	$ (0.7)	(17)%

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(c)	$ (155.1)	$ (149.6)	$ (5.5)	(4)%
Interest expense, net of unallocable interest income(d)	$ (205.9)	$ (197.6)	$ (8.3)	(4)%
Unallocable income tax expense	$ (4.6)	$ (4.4)	$ (0.2)	(5)%
Net income attributable to noncontrolling interests(e)	$ (7.7)	$ (8.1)	$ 0.4	5%

(a) 2009 and 2008 amounts include increases of $1.4 million in non-cash compensation expense allocated to us from KMI. We do not have any obligation, nor do we expect, to pay any amounts related to these expenses. 2009 amount also includes a $0.9 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.

(b) 2009 and 2008 amounts include increases in imputed interest expense of $0.3 million and $0.5 million, respectively, related to our 2007 Cochin Pipeline acquisition.

(c) 2009 and 2008 amounts include increases of $2.8 million in non-cash compensation expense allocated to us from KMI. We do not have any obligation, nor do we expect, to pay any amounts related to these expenses. 2009 amount also includes a $0.1 million increase in expense for certain Express pipeline system acquisition costs, and a $1.5 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.

(d) 2009 and 2008 amounts include increases in imputed interest expense of $0.8 million and $1.0 million, respectively, related to our 2007 Cochin Pipeline acquisition.

(e) 2009 amount includes a $0.2 million decrease in net income attributable to noncontrolling interests related to all of the six month 2009 items previously disclosed in the footnotes to the tables included in "—Results of Operations."

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services. We report our interest expense as "net," meaning that we have subtracted unallocated interest income from our total interest expense to arrive at one interest amount.

For the three and six months ended June 30, 2009, the certain items described in footnotes (a) and (c) to the tables above decreased our general and administrative expenses by $0.9 million and $1.4 million, respectively, when compared to the same 2008 periods. The remaining general and administrative expenses for the three months ended June 30, 2009 were essentially flat versus the same period last year, but the remaining expenses for the six month period of 2009 exceeded last year's expenses by $6.9 million (5%). The overall increase included a $5.5 million increase from higher employee benefit and payroll tax expenses in the first half of 2009, due mainly to cost inflation increases on work-based health and insurance benefits and to a larger year-over-year labor force.

We continue to manage aggressively our general and administrative expenses, and in light of the current economic uncertainties, we have taken additional measures to reduce our expenses since the start of the year. Specifically, we are reducing our travel and compensation costs where possible, decreasing our use of outside consultants, reducing overtime where possible, and reviewing our capital and operating budgets to identify costs we can reduce without compromising operating efficiency, maintenance or safety.

After taking into effect the certain items described in footnotes (b) and (d) to the tables above, our unallocable interest expense, net of interest income, increased $1.6 million (2%) in the second quarter of 2009 and $8.5 million (4%) in the first half of 2009, versus the same periods last year. The increases in interest expense were attributable to higher average debt balances—average borrowings increased 15% and 19%, respectively, in the comparable three and six month periods of 2009—but were partly offset by decreases of 15% and 13%, respectively, in the weighted average interest rate on all of our borrowings.

The increases in our average borrowings were largely due to the capital expenditures and joint venture contributions we have made since the end of the second quarter of 2008, driven primarily by continued investment in our Natural Gas Pipelines and CO_2 business segments. Generally, we initially fund our discretionary capital spending, the contributions we pay for our proportionate share of pipeline project construction costs, and our acquisition outlays from borrowings under our bank credit facility (or under our commercial paper program when we have access to the commercial paper market). From time to time, we issue senior notes and equity in order to refinance our commercial paper and credit facility borrowings.

The period-to-period decreases in our average borrowing rates reflect a general drop in variable interest rates since the end of the second quarter of 2008. We use interest rate swap agreements to transform a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. In periods of falling interest rates, these swaps will result in period-to-period decreases in our interest expense. As of June 30, 2009, approximately 52% of our $9,399.8 million consolidated debt balance (excluding the value of interest rate swap agreements) was subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 6 to our consolidated financial statements included elsewhere in this report.

The period-to-period fluctuations in both unallocable income tax expenses and net income attributable to noncontrolling interests were not significant in either the three or six month comparable periods of 2009 and 2008. Unallocable income tax expense relates to corporate-level income tax expense accruals (accrued by the Partnership) for the Texas margin tax, an entity-level tax imposed on the amount of our total revenue that is apportioned to the state of Texas. Income allocated to our noncontrolling interests represents the allocation of our consolidated net income attributable to all outstanding ownership interests in our five operating limited partnerships and their consolidated subsidiaries that are not held by us.

Financial Condition

General

As of June 30, 2009, we believe our balance sheet and liquidity position remained strong. Our short term debt, net of cash, was approximately $42.9 million. In addition, we demonstrated substantial flexibility in the term debt market by issuing an additional $1 billion in principal amount of senior notes in the second quarter of 2009 (receiving proceeds, after underwriting discounts and commissions, of $993.3 million).

Similarly, we demonstrated continued access to the equity market by raising approximately $712.5 million in net proceeds from equity offerings year to date, including $286.9 million from the public offering of 5,750,000 common units on June 12, 2009 (we received additional net cash proceeds of $43.0 million from the issuance of an additional 862,500 common units pursuant to the underwriters' exercise of an over-allotment option in July 2009). We have consistently generated strong cash flow from operations—generating $936.8 million in cash from operations in the first half of 2009—and we continue to have access to additional sources of liquidity though our $1.85 billion bank credit facility and our equity distribution agreement with UBS Securities LLC.

As of June 30, 2009, we had approximately $1.4 billion of borrowing capacity available under our credit facility (discussed below in "—Short-term Liquidity"). Furthermore, at KMI's third quarter 2008 board meeting held on October 15, 2008, KMI's board indicated its willingness to contribute up to $750 million of equity to us over the subsequent 18 months, if necessary, in order to support our capital raising efforts.

We believe that our cash generating business model provides us with the financial flexibility needed to operate our assets and make targeted investments in the business segments that present our best long-term opportunities, and as we continue to operate in the current challenging economic environment, we will also continue to focus on cost and expense reduction and improved efficiency.

Our primary cash requirements, in addition to normal operating expenses, are debt service, sustaining capital expenditures (defined as capital expenditures which do not increase the capacity of an asset), expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholder and general partner. In addition to utilizing cash generated from operations, we could meet our cash requirements for expansion capital expenditures through borrowings under our credit facility, issuing long-term notes or additional common units or the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of additional KMR shares.

In general, we expect to fund:

▪ cash distributions and sustaining capital expenditures with existing cash and cash flows from operating activities;

▪ expansion capital expenditures and working capital deficits with retained cash (resulting from including i-units in the determination of cash distributions per unit but paying quarterly distributions on i-units in additional i-units rather than cash), additional borrowings, the issuance of additional common units or the proceeds from purchases of additional i-units by KMR;

▪ interest payments with cash flows from operating activities; and

▪ debt principal payments with additional borrowings, as such debt principal payments become due, or by the issuance of additional common units or the proceeds from purchases of additional i-units by KMR.

In addition to our results of operations, our debt and capital balances are affected by our financing activities, as discussed below in "—Financing Activities."

Credit Ratings and Capital Market Liquidity

As part of our financial strategy, we try to maintain an investment-grade credit rating, which involves, among other things, the issuance of additional limited partner units in connection with our acquisitions and expansion activities in order to maintain acceptable financial ratios. Currently, our long-term corporate debt credit rating is BBB, Baa2 and BBB, respectively, at S&P, Moody's and Fitch. As a publicly traded limited partnership, our common units are attractive primarily to individual investors, although such investors represent a small segment of the total equity capital market. We believe that some institutional investors prefer shares of KMR over our common units due to tax and other regulatory considerations, and we are able to access this segment of the capital market through KMR's purchases of i-units issued by us with the proceeds from the sale of KMR shares to institutional investors.

On September 15, 2008, Lehman Brothers Holdings Inc. filed for bankruptcy protection under the provisions of Chapter 11 of the U.S. Bankruptcy Code. Lehman Brothers Commercial Bank was a lending institution that provided $63.3 million of the commitments under our credit facility. During the first quarter of 2009, we amended our facility to remove Lehman Brothers Commercial Bank as a lender, thus reducing the facility by $63.3 million. The commitments of the other banks remain unchanged, and the facility is not defaulted.

On October 13, 2008, S&P revised its outlook on our long-term credit rating to negative from stable (but affirmed our long-term credit rating at BBB), due to our previously announced expected delay and cost increases associated with the completion of the Rockies Express Pipeline project. At the same time, S&P lowered our short-term credit rating to A-3 from A-2. As a result of this revision to our short-term credit rating and the current commercial paper market conditions, we are unable to access commercial paper borrowings.

On May 6, 2009, Moody's downgraded our commercial paper rating to Prime-3 from Prime-2 and assigned a negative outlook to our long-term credit rating. The downgrade was primarily related to the increases, since the beginning of 2009, in our outstanding debt balance. However, we continue to maintain an investment grade credit rating, and all of our long-term credit ratings remain unchanged since December 31, 2008. Furthermore, we expect that our financing and our short-term liquidity needs will continue to be met through borrowings made under our bank credit facility. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the energy and terminals industries and other financial and business factors, some of which are beyond our control.

Additionally, some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. These financial problems may arise from the current financial crises, changes in commodity prices or otherwise. We have and are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our credit position relating to amounts owed from these customers. We cannot provide assurance that one or more of our current or future financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows; however, we believe we have provided adequate allowance for such customers.

Short-term Liquidity

Our principal sources of short-term liquidity are our (i) $1.85 billion senior unsecured revolving bank credit facility that matures August 18, 2010; and (ii) cash from operations (discussed below in "—Operating Activities"). Borrowings under our bank credit facility can be used for general partnership purposes and as a backup for our commercial paper program. The facility can be amended to allow for borrowings up to $2.04 billion (after reductions by the Lehman commitment). As of June 30, 2009, the outstanding balance under our bank credit facility was $100.0 million, and there were no borrowings under our commercial paper program. As of December 31, 2008, we had no outstanding borrowings under our credit facility or our commercial paper program.

As of June 30, 2009, our outstanding short-term debt was $145.4 million, primarily consisting of the $100.0 million of outstanding borrowings under our bank credit facility. We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our bank credit facility. After reduction for (i) our letters of credit; (ii) our outstanding borrowings under our credit facility; and (iii) the lending commitments made by Lehman Brothers Commercial Bank, which was canceled in connection with the Lehman Brothers bankruptcy (see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report), the remaining available borrowing capacity under our bank credit facility was $1,377.9 million as of June 30, 2009. Currently, we believe our liquidity to be adequate.

Long-term Financing

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements (other than distributions to our common unitholders, Class B unitholders and general partner) through issuing long-term notes or additional common units, or by utilizing the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of KMR shares.

We are subject, however, to conditions in the equity and debt markets for our limited partner units and long-term notes, and there can be no assurance we will be able or willing to access the public or private markets for our limited partner units and/or long-term notes in the future. If we were unable or unwilling to issue additional limited partner units, we would be required to either restrict potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. See "—Credit Ratings and Capital Market Liquidity" above for a discussion of our credit ratings.

As of June 30, 2009 and December 31, 2008, the total liability balance due on the various series of our senior notes was $9,130.1 million and $8,381.5 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $169.7 million and $182.1 million, respectively. For more information on our 2009 debt related transactions, including our issuances of senior notes, see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report, and for additional information regarding our debt securities and credit facility, see Note 9 to our consolidated financial statements included in our 2008 Form 10-K. For information on our equity issuances in the first half of 2009, including cash proceeds received from public offerings of common units and from our equity distribution agreement, see Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report

Capital Structure

We attempt to maintain a relatively conservative overall capital structure, financing our expansion capital expenditures and acquisitions with approximately 50% equity and 50% debt. In the short-term, we fund these expenditures from borrowings under our credit facility until the amount borrowed is of a sufficient size to cost effectively do either a debt or equity offering, or both.

With respect to our debt, we target a debt mixture of approximately 50% fixed and 50% variable interest rates. We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping the fixed rate interest payments for variable rate payments.

Capital Expenditures

Including both sustaining and discretionary spending, our capital expenditures were $796.6 million in the first six months of 2009, versus $1,262.6 million in the same year-ago period. Our sustaining capital expenditures, defined as capital expenditures which do not increase the capacity of an asset, totaled $70.7 million, compared to $76.8 million for 2008. These sustaining expenditure amounts include our proportionate share of Rockies Express' sustaining capital expenditures—approximately $0.1 million in the first six months of 2009 and less than $0.1 million in the first six months of 2008. Additionally, our forecasted expenditures for the remaining six months of 2009 for sustaining capital expenditures are approximately $111.7 million—including our proportionate shares of Rockies Express and Midcontinent Express. Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from its operations, Rockies Express can fund its cash requirements for capital expenditures through borrowings under its own credit facility, issuing its own long-term notes, or with proceeds from contributions received from its equity owners.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. The discretionary capital expenditures reflected in our consolidated statement of cash flows for the first half of 2009 and 2008 were $725.9 million and $1,185.8 million, respectively. Generally, we fund our discretionary capital expenditures (and our investment contributions) through borrowings under our bank credit facility. To the extent this source of funding is not sufficient, we generally fund additional amounts through the issuance of long-term notes or common units for cash. During the first half of 2009, we used sales of common units and the issuance of senior notes to refinance portions of our short-term borrowings under our bank credit facility.

Operating Activities

Net cash provided by operating activities was $936.8 million for the six months ended June 30, 2009, versus $974.7 million for the comparable period of 2008. The period-to-period decrease of $37.9 million (4%) in cash provided by operating activities primarily consisted of:

- a $165.4 million decrease in cash inflows relative to net changes in working capital items, primarily driven by reductions in customer deposits, lower net cash inflows from the collection and payment of trade and related party receivables and payables (including collections and payments on natural gas transportation and exchange imbalance receivables and payables), and higher payments in 2009 to settle certain refined product imbalance liabilities owed to U.S. military customers of our Products Pipelines business segment;

- a $35.0 million decrease in cash from overall lower partnership income—after adjusting for the following four non-cash items: depreciation, depletion and amortization expenses; undistributed earnings from equity investees; income from the allowance for equity funds used during construction; and income from the sales of property, plant and equipment. The year-to-year decrease in partnership income from our five reportable business segments in the first six months of 2009 and 2008 is discussed above in "—Results of Operations" (including all of the certain items disclosed in the associated table footnotes);

- a $25.7 million decrease in cash relative to changes in other non-current assets and liabilities, and other non-cash expenses, primarily driven by reductions in our Trans Mountain Pipeline's deferred revenue obligations and by higher payments for natural gas storage on our Kinder Morgan Interstate Gas Transmission system;

- a $144.4 million increase in cash from an interest rate swap termination payment we received in January 2009, when we terminated a fixed-to-variable interest rate swap agreement having a notional principal amount of $300 million and a maturity date of March 15, 2031; and

- a $36.0 million increase in cash related to higher distributions received from equity investments—chiefly due to incremental distributions of $43.1 million received from West2East Pipeline LLC, the sole owner of Rockies Express Pipeline LLC. We began receiving distributions on our 51% equity interest in West2East Pipeline LLC in the second quarter of 2008. When construction of the Rockies Express Pipeline is completed, our ownership interest will be reduced to 50% and the capital accounts of West2East Pipeline LLC will be trued-up to reflect our 50% economic interest in the project.

Investing Activities

Net cash used in investing activities was $1,537.9 million for the six month period ended June 30, 2009, compared to $1,654.9 million for the comparable 2008 period. The $117.0 million (7%) decrease in cash used in investing activities was primarily attributable to:

- a $466.0 million decrease in cash used for capital expenditures—largely due to the higher investment undertaken in the first half of 2008 to construct our Kinder Morgan Louisiana Pipeline and to expand our Trans Mountain crude oil and refined petroleum products pipeline system;

- a $182.2 million decrease in cash used for margin and restricted deposits in 2009 compared to 2008, associated largely with our utilization of derivative contracts to hedge (offset) against the volatility of energy commodity price risks;

- a $109.6 million decrease in cash used due to the full repayment received during the first six months of 2009 from a $109.6 million loan we made in December 2008 to a single customer of our Texas intrastate natural gas pipeline group;

- a $464.1 million increase in cash used due to higher contributions to equity investees in the first half of 2009, relative to the first six months a year ago. The increase was primarily driven by incremental contributions to West2East Pipeline LLC, Midcontinent Express Pipeline LLC, and Fayetteville Pipeline LLC to partially fund their respective Rockies Express, Midcontinent Express, and Fayetteville Express Pipeline construction and/or pre-construction costs. As discussed in Note 2 to our consolidated financial statements included elsewhere in this report, in the first half of 2009 we contributed a combined $797.7 million for these three pipeline projects, versus contributions of $333.5 million in the first half of 2008;

- an $89.1 million increase in cash used related to a return of capital received from Midcontinent Express Pipeline LLC in February 2008. During that month, Midcontinent entered into and then made borrowings under a new $1.4 billion three-year, unsecured revolving credit facility due February 28, 2011. Midcontinent then made distributions (in excess of cumulative earnings) to its two member owners to reimburse them for prior contributions made to fund its pipeline construction costs;

- a $52.6 million increase in cash used, relative to 2008, due to lower net proceeds received from the sales of investments, property, plant and equipment, and other net assets (net of salvage and removal costs). The decrease in cash sales proceeds was driven by the approximately $50.7 million we received in the second quarter of 2008 for the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC; and

- a $23.4 million increase in cash used related to a contribution received from KMI in April 2008, as a result of certain true-up provisions in our Trans Mountain acquisition agreement.

Financing Activities

Net cash provided by financing activities amounted to $638.6 million for the first half of 2009. For the first six months a year ago, our financing activities provided net cash of $701.0 million. The $62.4 million (9%) cash decrease from the comparable 2008 period was mainly due to:

- a $152.5 million decrease in cash from higher partnership distributions in the first six months of 2009, when compared to the same period last year. Distributions to all partners, including our common and Class B unitholders, our general partner and our noncontrolling interests, totaled $858.9 million in the first half of 2009, compared to $706.4 million in the same period last year;

- a $148.7 million decrease in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The period-to-period decrease in cash from overall financing activities was primarily due to (i) a $838.5 million decrease in cash due to lower net issuances and repayments of senior notes in the first half of 2009; (ii) a $589.1 million increase in cash due to net commercial paper repayments in the first half of 2008; and (iii) a $100.0 million increase in cash from incremental borrowings under our bank credit facility in the first half of 2009;

  The decrease in cash inflows from changes in senior notes outstanding reflects the combined $743.3 million we received from both issuing and repaying senior notes in 2009 (discussed in Note 4 to our consolidated financial statements included elsewhere in this report), versus the combined $1,581.8 million we received from our February and June 2008 public offerings of senior notes. Our 2008 debt offerings consisted of four separate series of senior notes, having an aggregate principal amount of $1.6 billion. We used the proceeds from each of these offerings to reduce the borrowings under our commercial paper program;

- a $48.7 million decrease in cash inflows from net changes in cash book overdrafts—resulting from timing differences on checks issued but not yet presented for payment; and

- a $285.2 million increase in cash from higher partnership equity issuances. The increase relates to the combined $669.5 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first half of 2009 (discussed in Note 5 to our consolidated financial statements included elsewhere in this report), versus the combined $384.3 million we received from two separate offerings of common units in the first half of 2008. The $384.3 million in proceeds received in 2008 included $60.1 million from the issuance of 1,080,000 common units in a privately negotiated transaction completed in February 2008, and $324.2 million from the issuance of 5,750,000 additional common units pursuant to a public offering completed in March 2008. We used the proceeds from each of these two offerings to reduce the borrowings under our commercial paper program.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of “Available Cash,” as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Our 2008 Form 10-K contains additional information concerning our partnership distributions, including the definition of “Available Cash,” the manner in which our total distributions are divided between our general partner and our limited partners, and the form of distributions to all of our partners, including our noncontrolling interests.

On May 15, 2009, we paid a quarterly distribution of $1.05 per unit for the first quarter of 2009. This distribution was 9% greater than the $0.96 distribution per unit we paid in May 2008 for the first quarter of 2008. We paid this distribution in cash to our general partner and to our common and Class B unitholders. KMR, our sole i-unitholder, received additional i-units based on the $1.05 cash distribution per common unit. On July 15, 2009, we declared a cash distribution of $1.05 per unit for the second quarter of 2009 (an annualized rate of $4.20 per unit). This distribution was 6% higher than the $0.99 per unit distribution we made for the second quarter of 2008.

The incentive distribution that we paid on May 15, 2009 to our general partner (for the first quarter of 2009) was $223.2 million. Our general partner’s incentive distribution that we paid in May 2008 (for the first quarter of 2008) was $185.8 million. Our general partner’s incentive distribution for the distribution that we declared for the second quarter of 2009 is $231.8 million, and our general partner’s incentive distribution for the distribution that we paid for the second quarter of 2008 was $194.2 million. The period-to-period increases in our general partner incentive distributions resulted from both increased cash distributions per unit and increases in the number of common units and i-units outstanding.

Additionally, in November 2008, we announced that we expected to declare cash distributions of $4.20 per unit for 2009, almost a 4.5% increase over our cash distribution of $4.02 per unit for 2008. Although the majority of the cash generated by our assets is fee based and is not sensitive to commodity prices, our CO_2 business segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids. While we hedge the majority of our crude oil production, we do have exposure on our unhedged volumes, the majority of which are natural gas liquids. Our 2009 distribution expectation assumes an average West Texas Intermediate crude oil price of $68 per barrel (with some minor adjustments for timing, quality and location differences). Based on the actual prices we have received through the date of this report and the forward price curve for WTI (adjusted for the same factors used in our 2009 budget), we currently expect to realize an average WTI crude oil price of approximately $58 per barrel in 2009. For 2009, we expect that every $1 change in the average WTI crude oil price per barrel will impact our CO_2 segment’s cash flows by approximately $6 million (or approximately 0.2% of our combined business segments’ distributable cash flow).

To offset the lower crude prices, as well as other headwinds we face from ongoing weak market conditions, we have identified a number of areas across our company to minimize costs and maximize revenues without compromising operational safety or efficiency. Since the start of 2009, (i) we have continued to focus on reducing our general and administrative expenses across our business portfolio wherever possible; (ii) our CO_2 business segment has negotiated lower contract prices with various oil and gas material and service suppliers, thereby lowering its operating and maintenance expenses; (iii) our Terminals segment has entered into various term supply contracts to lower its costs of diesel fuel; and (iv) average interest rates have been lower than originally anticipated for 2009, resulting in lower interest expense on our outstanding debt. We expect these items to further benefit us throughout the year, and as a result of these cost reductions and other opportunities that we have identified, we continue to expect that we will achieve our budget target of $4.20 per unit in cash distributions for 2009.

Recent Accounting Pronouncements

Please refer to Note 12 to our consolidated financial statements included elsewhere in this report for information concerning recent accounting pronouncements.

Information Regarding Forward-Looking Statements

This filing includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "position," "continue," "estimate," "expect," "may," or the negative of those terms or other variations of them or comparable terminology. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, natural gas, electricity, coal and other bulk materials and chemicals in North America;

- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;

- changes in our tariff rates implemented by the Federal Energy Regulatory Commission or the California Public Utilities Commission;

- our ability to acquire new businesses and assets and integrate those operations into our existing operations, as well as our ability to expand our facilities;

- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;

- our ability to successfully identify and close acquisitions and make cost-saving changes in operations;

- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;

- changes in crude oil and natural gas production from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the U.S. Rocky Mountains and the Alberta oil sands;

- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;

- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;

- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement that portion of our business plan that contemplates growth through acquisitions of operating businesses and assets and expansions of our facilities;

- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, and/or place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;

- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism, war or other causes;

- our ability to obtain insurance coverage without significant levels of self-retention of risk;

- acts of nature, sabotage, terrorism or other similar acts causing damage greater than our insurance coverage limits;
- capital and credit markets conditions, inflation and interest rates;
- the political and economic stability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- foreign exchange fluctuations;
- the timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;
- the extent of our success in discovering, developing and producing oil and gas reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;
- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and workovers, and in drilling new wells;
- the uncertainty inherent in estimating future oil and natural gas production or reserves;
- the ability to complete expansion projects on time and on budget;
- the timing and success of our business development efforts; and
- unfavorable results of litigation and the fruition of contingencies referred to in Note 10 to our consolidated financial statements included elsewhere in this report.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this report are reasonable. However, there is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

See Item 1A "Risk Factors" of our 2008 Form 10-K for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in our 2008 Form 10-K. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2008, in Item 7A of our 2008 Form 10-K. For more information on our risk management activities, see Note 6 to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of June 30, 2009, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule

13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting during the quarter ended June 30, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Note 10 to our consolidated financial statements entitled “Litigation, Environmental and Other Contingencies,” which is incorporated in this item by reference.

Item 1A. Risk Factors.

There have been no material changes in or additions to the risk factors disclosed in Part I, Item 1A “Risk Factors” in our 2008 Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Effective April 24, 2009, we issued 105,752 common units as the purchase price for ownership interests in certain oil and gas properties. The units were valued at $5.0 million, based on the average of the closing prices of our common units on the New York Stock Exchange for the five trading day period ended April 23, 2009, and were issued to the two sellers of the properties in a transaction not involving a public offering, exempt from registration pursuant to Section 4(2) of the Securities Act of 1933.

Item 3. Defaults Upon Senior Securities.

None.

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

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

4.1 -- Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec.229.601. Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.

4.2 -- Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.625% Senior Notes due 2015, and the 6.85% Senior Notes due 2020.

11 -- Statement re: computation of per share earnings.

12 -- Statement re: computation of ratio of earnings to fixed charges.

31.1 -- Certification by CEO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 -- Certification by CFO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 -- Certification by CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 -- Certification by CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101 -- Interactive Data File.

SIGNATURE

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.

KINDER MORGAN ENERGY PARTNERS, L.P.
Registrant (A Delaware limited partnership)

By: **KINDER MORGAN G.P., INC.,**
its sole General Partner

By: **KINDER MORGAN MANAGEMENT, LLC**,
the Delegate of Kinder Morgan G.P., Inc.

/s/ Kimberly A. Dang

Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)
Date: July 31, 2009