F O R M 10-Q

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **June 30, 2008**

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

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 [ ]

The Registrant had 177,054,734 common units outstanding as of July 31, 2008.

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PART I. FINANCIAL INFORMATION

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Revenues				
Natural gas sales	$ 2,464.7	$ 1,544.6	$ 4,185.9	$ 2,948.9
Services	677.8	595.7	1,353.5	1,152.7
Product sales and other	353.2	226.1	676.6	436.5
	3,495.7	2,366.4	6,216.0	4,538.1
Costs, Expenses and Other				
Gas purchases and other costs of sales	2,494.2	1,538.5	4,226.3	2,924.3
Operations and maintenance	236.6	201.2	459.7	399.8
Fuel and power	71.6	58.3	134.9	110.6
Depreciation, depletion and amortization	165.6	133.5	323.7	263.8
General and administrative	72.8	89.4	149.6	159.7
Taxes, other than income taxes	51.0	38.1	99.0	73.1
Goodwill impairment expense	—	—	—	377.1
Other expense (income)	(2.3)	(7.2)	(2.8)	(9.4)
	3,089.5	2,051.8	5,390.4	4,299.0
Operating Income	406.2	314.6	825.6	239.1
Other Income (Expense)				
Earnings from equity investments	46.2	17.3	83.9	35.6
Amortization of excess cost of equity investments	(1.5)	(1.5)	(2.9)	(2.9)
Interest, net	(98.8)	(97.1)	(195.5)	(187.9)
Other, net	23.3	3.8	26.2	4.4
Minority Interest	(4.1)	(3.2)	(8.1)	(2.0)
Income from Continuing Operations Before Income Taxes	371.3	233.9	729.2	86.3
Income Taxes	(9.9)	(6.6)	(21.6)	(15.6)
Income from Continuing Operations	361.4	227.3	707.6	70.7
Discontinued Operations (Note 2):				
Income from operations of North System	—	5.4	—	12.5
Adjustment to gain on disposal of North System	0.8	—	1.3	—
Income from Discontinued Operations	—	5.4	1.3	12.5
Net Income	$ 362.2	$ 232.7	$ 708.9	$ 83.2
Calculation of Limited Partners' interest in Net Income (Loss):				
Income from Continuing Operations	$ 361.4	$ 227.3	$ 707.6	$ 70.7
Less: General Partner's interest	(195.9)	(148.2)	(383.3)	(284.2)
Limited Partners' interest	165.5	79.1	324.3	(213.5)
Add: Limited Partners' interest in Discontinued Operations	0.8	5.4	1.3	12.4
Limited Partners' interest in Net Income (Loss)	$ 166.3	$ 84.5	$ 325.6	$ (201.1)
Basic and Diluted Limited Partners' Net Income (Loss) per Unit:				
Income (Loss) from Continuing Operations	$ 0.64	$ 0.34	$ 1.28	$ (0.92)
Income (Loss) from Discontinued Operations	0.01	0.02	—	0.06
Net Income (Loss)	$ 0.65	$ 0.36	$ 1.28	$ (0.86)
Weighted average number of units used in computation of Limited Partners' Net Income (Loss) per unit:				
Basic	256.7	235.0	253.9	233.0
Diluted	256.7	235.0	253.9	233.1
Per unit cash distribution declared	$ 0.99	$ 0.85	$ 1.95	$ 1.68

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, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 78.7	$ 58.9
Restricted deposits	275.0	67.9
Accounts, notes and interest receivable, net		
Trade	1,412.5	960.2
Related parties	8.2	3.6
Inventories		
Products	23.2	19.5
Materials and supplies	19.1	18.3
Gas imbalances		
Trade	9.7	21.2
Related parties	—	5.7
Gas in underground storage	51.3	—
Other current assets	96.6	54.4
	1,974.3	1,209.7
Property, Plant and Equipment, net	12,535.2	11,591.3
Investments	882.5	655.4
Notes receivable		
Trade	0.1	0.1
Related parties	86.3	87.9
Goodwill	1,089.4	1,077.8
Other intangibles, net	213.3	238.6
Deferred charges and other assets	367.9	317.0
Total Assets	$ 17,149.0	$ 15,177.8
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Accounts payable		
Cash book overdrafts	$ 46.1	$ 19.0
Trade	1,295.7	926.7
Related parties	24.1	22.6
Current portion of long-term debt	270.9	610.2
Accrued interest	149.1	131.2
Accrued taxes	58.7	73.8
Deferred revenues	23.6	22.8
Gas imbalances		
Trade	11.3	23.7
Related parties	5.1	—
Accrued other current liabilities	1,423.3	728.3
	3,307.9	2,558.3
Long-Term Liabilities and Deferred Credits		
Long-term debt		
Outstanding	7,785.6	6,455.9
Value of interest rate swaps	142.9	152.2
	7,928.5	6,608.1
Deferred revenues	17.2	14.2
Deferred income taxes	206.9	202.4
Asset retirement obligations	75.9	50.8
Other long-term liabilities and deferred credits	2,384.4	1,254.1
	10,612.9	8,129.6
Commitments and Contingencies (Note 3)		
Minority Interest	42.5	54.2
Partners' Capital		
Common Units	3,346.7	3,048.4
Class B Units	99.4	102.0
i-Units	2,501.4	2,400.8
General Partner	183.7	161.1
Accumulated other comprehensive loss	(2,945.5)	(1,276.6)
	3,185.7	4,435.7
Total Liabilities and Partners' Capital	$ 17,149.0	$ 15,177.8

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,	
	2008	**2007**
Cash Flows From Operating Activities		
Net Income	$ 708.9	$ 83.2
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	323.7	268.5
Amortization of excess cost of equity investments	2.9	2.9
Impairment of goodwill	—	377.1
Gains from property casualty indemnifications	—	(1.8)
Gains and other non-cash income from the sale of property, plant and equipment and investments	(17.1)	(7.9)
Earnings from equity investments	(83.9)	(36.8)
Distributions from equity investments	64.3	67.3
Proceeds from termination of interest rate swap agreement	—	15.0
Changes in components of working capital:		
Accounts receivable	(457.4)	165.6
Other current assets	(34.8)	(19.0)
Inventories	(4.7)	(1.4)
Accounts payable	389.3	(122.3)
Accrued interest	17.8	25.5
Accrued liabilities	89.9	(44.3)
Accrued taxes	(7.7)	14.3
Rate reparations, refunds and other litigation reserve adjustments	(23.3)	—
Other, net	6.8	(0.6)
Net Cash Provided by Operating Activities	974.7	785.3
Cash Flows From Investing Activities		
Acquisitions of assets	(4.2)	(47.8)
Repayment (Payment) for Trans Mountain	23.4	(549.0)
Additions to property, plant and equip. for expansion and maintenance projects	(1,262.6)	(690.4)
Sale of property, plant and equipment, and other net assets net of removal costs	47.9	7.7
Property casualty indemnifications	—	8.0
Investments in margin deposits	(207.1)	(5.5)
Contributions to equity investments	(338.7)	(43.8)
Distributions from equity investments	89.1	—
Natural gas stored underground and natural gas liquids line-fill	(2.7)	9.9
Net Cash Used in Investing Activities	(1,654.9)	(1,310.9)
Cash Flows From Financing Activities		
Issuance of debt	4,769.3	3,934.9
Payment of debt	(3,770.6)	(3,093.2)
Repayments from related party	1.5	1.1
Debt issue costs	(10.3)	(11.5)
Increase (Decrease) in cash book overdrafts	27.1	(5.5)
Proceeds from issuance of common units	384.3	—
Proceeds from issuance of i-units	—	297.9
Contributions from minority interest	5.9	4.1
Distributions to partners:		
Common units	(326.6)	(270.5)
Class B units	(10.0)	(8.8)
General Partner	(360.9)	(260.7)
Minority interest	(8.9)	(8.0)
Other, net	0.2	0.1
Net Cash Provided by Financing Activities	701.0	579.9
Effect of exchange rate changes on cash and cash equivalents	(1.0)	0.6
Increase in Cash and Cash Equivalents	19.8	54.9
Cash and Cash Equivalents, beginning of period	58.9	6.7
Cash and Cash Equivalents, end of period	$ 78.7	$ 61.6
Noncash Investing and Financing Activities:		
Assets acquired by the assumption or incurrence of liabilities	$ 2.3	$ 18.5
Assets acquired by the issuance of units—liability settlement	—	$ 15.0

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

1. Organization

General

Unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries. 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 Annual Report on Form 10-K for the year ended December 31, 2007, referred to in this report as 2007 Form 10-K.

Knight Inc. (formerly known as Kinder Morgan, Inc.), Kinder Morgan G.P., Inc. and Kinder Morgan Management, LLC

Knight Inc., referred to as "Knight" in this report, is a private company 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. Additional investors in Knight include, among others, certain members of Knight's senior management, most of whom are also senior officers of our general partner and of its delegate. Before completing its going-private transaction on May 30, 2007, and subsequently being renamed, Knight was known as Kinder Morgan, Inc., a Kansas corporation referred to as "KMI" in this report.

Knight remains the sole indirect common stockholder of our general partner. On July 27, 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 2007 Form 10-K.

Basis of Presentation

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. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior periods have been reclassified to conform to the current presentation.

Our accompanying consolidated financial statements reflect amounts on a historical cost basis, and, accordingly, do not reflect any purchase accounting adjustments related to the May 30, 2007 going-private transaction of KMI, now known as Knight. In addition, as discussed in Note 2 below, our financial statements included in this report include the transactions, balances and results of operations of our Trans Mountain pipeline system as if it had been transferred to us on January 1, 2006. Also, during the second quarter of 2008, we changed the date of our annual goodwill impairment test date to May 31 of each year. This change constitutes a change in the method of applying an accounting principle, as discussed in paragraph 4 of SFAS No. 154, "Accounting Changes and Error Corrections." For more information on this change, see Note 6.

Net Income Per Unit

We compute Basic 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. Diluted Limited Partners' Net Income per Unit reflects the maximum potential dilution that could occur if units whose issuance depends on the market price of the units at a future date were considered outstanding, or if, by application of the treasury stock method, options to issue units were exercised, both of which would result in the issuance of additional units that would then share in our net income.

Emerging Issues Task Force Issue No. 03-6, or EITF 03-6, "Participating Securities and the Two-Class Method Under FASB Statement No. 128" addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its securities. In addition, effective January 1, 2009, we will begin calculating our Net Income per Unit according to the provisions of 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 partnerships, under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed regardless of whether a general partner has discretion over the amount of distribution to be made for any particular period. For more information regarding EITF 07-4, see Note 15.

2. Acquisitions, Joint Ventures and Divestitures

Acquisitions

During the first six months of 2008, we did not complete any previously unannounced material business acquisitions or enter into any new joint ventures; however, we did record purchase price adjustments related to our previously completed acquisitions of bulk terminal operations acquired effective May 30, 2007 and September 1, 2007, respectively.

On May 30, 2007, we purchased the Vancouver Wharves bulk marine terminal from British Columbia Railway Company, a crown corporation owned by the Province of British Columbia, for an aggregate consideration of $59.5 million, consisting of $38.8 million in cash and $20.7 million in assumed liabilities. The Vancouver Wharves facility is located on the north shore of the Port of Vancouver's main harbor and includes five deep-sea vessel berths situated on a 139-acre site. The terminal assets include significant rail infrastructure, dry bulk and liquid storage, and material handling systems that allow the terminal to handle over 3.5 million tons of cargo annually.

The acquisition both expanded and complemented our existing terminal operations, and all of the acquired assets are included in our Terminals business segment. In the first half of 2008, we made our final purchase price adjustments to reflect final fair value of acquired assets and final expected value of assumed liabilities. Our adjustments increased "Property, Plant and Equipment, net" by $2.7 million, reduced working capital balances by $1.6 million, and increased long-term liabilities by $1.1 million.

Additionally, on September 1, 2007, we acquired certain bulk terminals assets from Marine Terminals, Inc. for an aggregate consideration of approximately $101.6 million, consisting of $100.4 million in cash and an assumed liability of $1.2 million. The acquired assets and operations are included in our Terminals business segment and are primarily involved in the handling and storage of steel and alloys. The operations consist of two separate facilities located in Blytheville, Arkansas, and individual terminal facilities located in Decatur, Alabama, Hertford, North Carolina, and Berkley, South Carolina. Combined, the five facilities handle approximately 13.5 million tons of alloys and steel products annually and also provide stevedoring and harbor services, scrap handling, and scrap processing services to customers in the steel and alloys industry.

Based on our estimate of fair market values, we allocated $60.8 million of our combined purchase price to "Property, Plant and Equipment, net;" $21.7 million to "Other intangibles, net;" $18.1 million to "Goodwill;" and $1.0 million to "Other current assets" or "Deferred charges and other assets." As of June 30, 2008, our allocation of the purchase price was preliminary, pending final determination of certain post-closing adjustments pursuant to the purchase and sale agreement. We do not expect these final purchase price adjustments to be significant, and we expect all adjustments and settlements will be completed in the third quarter of 2008.

The allocation to "Other intangibles, net" included a $20.1 million amount representing the fair value of a service contract entered into with Nucor Corporation, a large domestic steel company with significant operations in the Southeast region of the United States. For valuation purposes, the service contract was determined to have a useful life of 20 years, and pursuant to the contract's provisions, the acquired terminal facilities will continue to provide Nucor with handling, processing, harboring and warehousing services.

The allocation to "Goodwill," which is expected to be deductible for tax purposes, was based on the fact that this acquisition both expanded and complemented our existing ferro alloy terminal operations and will provide Nucor and other customers further access to our growing national network of marine and rail terminals. We believe the acquired value of the assets, including all contributing intangible assets, exceeded the fair value of acquired identifiable net assets and liabilities—in the aggregate, these factors represented goodwill.

Joint Ventures

In the first six months of 2008, we made capital contributions of $306.0 million to West2East Pipeline LLC (the sole owner of Rockies Express Pipeline LLC) to partially fund its Rockies Express Pipeline construction costs. We included this cash contribution as an increase to "Investments" in our accompanying consolidated balance sheet as of June 30, 2008, and we included it within "Contributions to equity investments" in our accompanying consolidated statement of cash flows for the six months ended June 30, 2008. We own a 51% equity interest in the West2East Pipeline LLC.

On June 24, 2008, Rockies Express completed a private offering of senior notes. It issued an aggregate of $1.3 billion in principal amount of fixed rate senior notes under an indenture between itself and U.S. Bank National Association, as trustee, in a private transaction that was not subject to the registration requirements of the Securities Act of 1933, but instead was subject to the requirements of Rule 144A under the Act. Rockies Express received net proceeds of approximately $1.29 billion from this offering, after deducting the initial purchasers' discount and estimated offering expenses, and virtually all of the net proceeds from the sale of the notes were used to repay short-term commercial paper borrowings.

The indenture included the issuance of three separate series of notes, as follows:

- $500 million in principal amount of 6.25% senior notes due July 15, 2013;

- $550 million in principal amount of 6.85% senior notes due July 15, 2018; and

- $250 million in principal amount of 7.50% senior notes due July 15, 2038.

Interest on the notes will be paid semiannually on January 15 and July 15 of each year, commencing on January 15, 2009. All payments of principal and interest in respect of the notes are the sole obligation of Rockies Express. Noteholders will have no recourse against us, Sempra Energy or ConocoPhillips, or against any of our or their respective officers, directors, employees, shareholders, members, managers, unitholders or affiliates for any failure by Rockies Express to perform or comply with its obligations pursuant to the notes or the indenture.

Pro Forma Information

Pro forma consolidated income statement information that assumes all of the acquisitions we have made and all of the joint ventures we have entered into since January 1, 2007 had occurred as of January 1, 2007 is not materially different from the information presented in our accompanying consolidated statements of income.

Trans Mountain Pipeline System

On April 30, 2007, we acquired the Trans Mountain pipeline system from Knight for $549.1 million in cash. The transaction was approved by the independent directors of both Knight and KMR following the receipt by such directors of separate fairness opinions from different investment banks. We paid $549 million of the purchase price on April 30, 2007, and we paid the remaining $0.1 million in July 2007.

In April 2008, as a result of finalizing certain “true-up” provisions in our acquisition agreement related to Trans Mountain pipeline expansion spending, we received a cash contribution of $23.4 million from Knight. Pursuant to the accounting provisions concerning transfers of net assets between entities under common control, and consistent with our treatment of cash payments made to Knight for Trans Mountain net assets in 2007, we accounted for this cash contribution as an adjustment to equity—primarily as an increase in “Partners’ Capital” in our accompanying consolidated balance sheet. We also included this $23.4 million receipt as a cash inflow item from investing activities in our accompanying consolidated statement of cash flows.

Effective January 1, 2006, Knight, which indirectly owns all the common stock of our general partner, according to the provisions of 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,” was deemed to have control over us and no longer accounted for its investment in us under the equity method of accounting, but instead included our accounts, balances and results of operations in its consolidated financial statements. As required by the provisions of Statement of Financial Accounting Standards No. 141, “Business Combinations,” we accounted for our acquisition of Trans Mountain as a transfer of net assets between entities under common control. For combinations of entities under common control, the purchase cost provisions (as they relate to purchase business combinations involving unrelated entities) of SFAS No. 141 explicitly do not apply; instead the method of accounting prescribed by SFAS No. 141 for such transfers is similar to the pooling-of-interests method of accounting. Under this method, the carrying amount of net assets recognized in the balance sheets of each combining entity are carried forward to the balance sheet of the combined entity, and no other assets or liabilities are recognized as a result of the combination (that is, no recognition is made for a purchase premium or discount representing any difference between the cash consideration paid and the book value of the net assets acquired).

Therefore, following our acquisition of Trans Mountain from Knight on April 30, 2007, we recognized the Trans Mountain assets and liabilities acquired at their carrying amounts (historical cost) in the accounts of Knight (the transferring entity) at the date of transfer. The accounting treatment for combinations of entities under common control is consistent with the concept of poolings as combinations of common shareholder (or unitholder) interests, as all of Trans Mountain’s equity accounts were also carried forward intact initially, and subsequently adjusted due to the cash consideration we paid for the acquired net assets.

In addition to requiring that assets and liabilities be carried forward at historical costs, SFAS No. 141 also prescribes that for transfers of net assets between entities under common control, all income statements presented be combined as of the date of common control. Accordingly, our consolidated financial statements and all other financial information included in this report have been prepared assuming that the transfer of Trans Mountain net assets from Knight to us had occurred at the date when both Trans Mountain and we met the accounting requirements for entities under common control (January 1, 2006), and therefore, our 2007 results of operations include Knight’s recognition of a $377.1 million goodwill impairment recorded in the first quarter of 2007. For more information on this impairment expense, see Note 6.

The Trans Mountain pipeline system, which transports crude oil and refined products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington, completed a pump station expansion in April 2007 that increased pipeline throughput capacity to approximately 260,000 barrels per day. An additional expansion that increased pipeline capacity by 25,000 barrels per day was completed and began service on May 1, 2008. We expect to complete construction on a final 15,000 barrel per day expansion by November 2008, and upon completion, total pipeline capacity will then be approximately 300,000 barrels per day.

In addition, due to the fact that Trans Mountain's operations are managed separately, involve different products and marketing strategies, and produce discrete financial information that is separately evaluated internally by our management, we have identified our Trans Mountain pipeline system as a separate reportable business segment.

Divestitures

Thunder Creek Gas Services, LLC

Effective April 1, 2008, we sold our 25% ownership interest in Thunder Creek Gas Services, LLC to PVR Midstream LLC, a subsidiary of Penn Virginia Corporation. Prior to the sale, we accounted for our investment in Thunder Creek Gas Services, LLC, referred to in this report as Thunder Creek, under the equity method of accounting and included its financial results within our Natural Gas Pipelines business segment. In the second quarter of 2008, we received cash proceeds, net of closing costs and settlements, of approximately $50.7 million for our investment, and we recognized a gain of $13.0 million with respect to this transaction. We used the proceeds from this sale to reduce the outstanding balance on our commercial paper borrowings, and we included the amount of the gain within the caption "Other, net" in our accompanying consolidated statements of income for the three and six months ended June 30, 2008.

Thunder Creek provides natural gas gathering, compression and treating service to a number of coal seam gas producers in the Powder River Basin of northeast Wyoming. Thunder Creek's operations are a combination of mainline and low pressure gathering assets, and throughput volumes include both coal seam and conventional plant residue gas. The mainline assets include 125 miles of mainline pipeline, 230 miles of high and low pressure laterals, approximately 26,600 horsepower of mainline compression, and carbon dioxide removal facilities consisting of a 220 million cubic feet per day carbon dioxide treating plant with natural gas dehydration capability. Devon Energy owns the remaining 75% ownership interest.

North System Natural Gas Liquids Pipeline System – Discontinued Operations

On July 2, 2007, we announced that we entered into an agreement to sell the 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) to ONEOK Partners, L.P. for approximately $298.6 million in cash. Our investment in net assets, including all transaction related accruals, was approximately $145.8 million, most of which represented property, plant and equipment, and we recognized approximately $152.8 million of gain in the fourth quarter of 2007 from the sale of these net assets. In the first half of 2008, following final account and inventory reconciliations, we paid a net amount of $2.4 million to ONEOK to fully settle the sale of (i) working capital items; (ii) total physical product liquids inventory and inventory obligations for certain liquids products; and (iii) the allocation of pre-acquisition investee distributions. Based primarily upon these adjustments, we recognized additional gains of $0.8 million and $1.3 million, respectively, in the three and six months ended June 30, 2008, and we reported these gains separately as "Adjustment to gain on disposal of North System" within the discontinued operations section of our accompanying consolidated statements of income.

The North System consists of an approximately 1,600-mile interstate common carrier pipeline system that delivers natural gas liquids and refined petroleum products from south central Kansas to the Chicago area. Also included in the sale were eight propane truck-loading terminals, located at various points in three states along the pipeline system, and one multi-product terminal complex located in Morris, Illinois. Prior to the sale, all of the assets were included in our Products Pipelines business segment.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we accounted for the North System business as a discontinued operation whereby the financial results and the gains on disposal of the North System have been reclassified to discontinued operations in our accompanying consolidated statements of income. Summarized financial information of the North System is as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Operating revenues	$ —	$ 13.4	$ —	$ 26.7
Operating expenses	—	(6.2)	—	(10.7)
Depreciation and amortization	—	(2.3)	—	(4.7)
Earnings from equity investments	—	0.5	—	1.2
Income from operations	—	5.4	—	12.5
Gain on disposal	0.8	—	1.3	—
Earnings from Discontinued Operations	$ 0.8	$ 5.4	$ 1.3	$ 12.5

Additionally, in our accompanying consolidated statement of cash flows for the six months ended June 30, 2007, we elected not to present separately the North System's operating and investing cash flows as discontinued operations, and, due to the fact that the sale of the North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments pursuant to the provisions of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," we have included the North System's financial results within our Products Pipelines business segment disclosures presented in this report for the three and six months ended June 30, 2007.

3. 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 three months ended June 30, 2008. Additional information with respect to these proceedings can be found in Note 16 to our audited financial statements that were filed with our 2007 Form 10-K.

Federal Energy Regulatory Commission Proceedings

Our SFPP, L.P. and Calnev Pipe Line LLC subsidiaries are involved in various proceedings before the Federal Energy Regulatory Commission, referred to in this note as the FERC. The tariffs and rates charged by SFPP and Calnev are subject to numerous ongoing proceedings at the FERC, including shippers' complaints and protests regarding interstate rates on these pipeline systems. In general, these complaints allege the rates and tariffs charged by SFPP and Calnev are not just and reasonable.

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, referred to in this note as EPAct 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 may become effective without investigation; (iv) the capital structure to be used in computing the "starting rate base" of our Pacific operations; (v) the level of income tax allowance we may include in our rates; and (vi) the recovery of civil and regulatory litigation expenses and certain pipeline reconditioning and environmental costs incurred by our Pacific operations.

In May 2005, the FERC issued a statement of general policy stating it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement.

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; Mobil Oil Corporation as Mobil; ExxonMobil Oil Corporation as ExxonMobil; Tosco Corporation as Tosco; ConocoPhillips Company as ConocoPhillips; Ultramar Diamond Shamrock Corporation/Ultramar Inc. as Ultramar; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; and America

West Airlines, Inc., Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airline Complainants.

Following are a summary of developments during the second quarter of 2008 and a listing of certain active FERC proceedings pertaining to our Pacific operations:

- 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
  Consolidated proceeding involving shipper complaints against certain East Line and West Line rates. All six issues (and others) described above are involved in these proceedings. Portions of this proceeding were appealed (and re-appealed) to the United States Court of Appeals for the District of Columbia Circuit, referred to in this note as the D.C. Court, and remanded to the FERC. Portions of this proceeding are currently being held in abeyance by the D.C. Court pending completion of agency proceedings. BP WCP, Chevron, and ExxonMobil requested a hearing before the FERC on remanded grandfathering and income tax allowance issues. The FERC issued an Order on Rehearing, Remand, Compliance, and Tariff Filings on December 26, 2007, which denied the requests for a hearing, and ruled on SFPP's March 7, 2006 compliance filing and remand issues. The FERC, *inter alia*, affirmed its income tax allowance policy, further clarified the implementation of that policy with respect to SFPP, and required SFPP to file a compliance filing. On February 15, 2008, the FERC issued an order granting and denying rehearing regarding certain findings in the December 2007 order;

- FERC Docket No. OR92-8-025—Complainants/Protestants: BP WCP; ExxonMobil; Chevron; ConocoPhillips; and Ultramar—Defendant: SFPP
  Proceeding involving shipper complaints against rates charged prior to April 1, 1999 at SFPP's Watson Station drain-dry facilities. A settlement reserved the issue of whether reparations were owed for the period prior to April 1, 1999. On February 12, 2008, the FERC ruled that SFPP owed reparations for shipments prior to April 1, 1999, and in March 2008, SFPP made required reparation payments of $23.3 million;

- FERC Docket No. OR96-2, *et al.*—Complainants/Protestants: All Shippers except Chevron (which is an intervenor)—Defendant: SFPP
  Consolidated proceeding involving shipper complaints against all SFPP rates. All six issues (and others) described above are involved in these proceedings. Portions of this proceeding were appealed (and re-appealed) to the D.C. Court and remanded to the FERC. Portions of this proceeding are currently being held in abeyance by the D.C. Court pending completion of agency proceedings. The FERC issued an Order on Rehearing, Remand, Compliance, and Tariff Filings on December 26, 2007, which denied the requests for a hearing and ruled on SFPP's March 7, 2006 compliance filing and remand issues. The FERC, *inter alia*, affirmed its income tax allowance policy and further clarified the implementation of that policy with respect to SFPP, and required SFPP to file a compliance filing. On February 15, 2008, the FERC issued an order granting and denying rehearing regarding certain findings in the December 2007 order. On May 2, 2008, the FERC issued an order reopening the record for a paper hearing on issues related to rate of return on equity applicable to the Sepulveda Line service in light of the FERC's policy statement issued in April of 2008 regarding the methodology for determining returns on equity. The parties have reached a settlement regarding the sole issue of the numeric value of the rate of return on equity to be applied in this proceeding with respect to the Sepulveda Line service that, upon approval by the FERC, would obviate the need for the paper hearing;

- FERC Docket Nos. OR02-4 and OR03-5—Complainant/Protestant: Chevron—Defendant: SFPP
  Chevron initiated proceeding to permit Chevron to become complainant in OR96-2. Appealed to the D.C. Court and held in abeyance pending final disposition of the OR96-2 proceedings;

- FERC Docket No. OR04-3—Complainants/Protestants: America West Airlines; Southwest Airlines; Northwest Airlines; and Continental Airlines—Defendant: SFPP
  Complaint alleges that West Line and Watson Station rates are unjust and unreasonable. Watson Station issues severed and consolidated into a proceeding focused only on Watson-related issues. The FERC has set the complaints against the West Line rates for hearing but denied the request to consolidate the dockets with the ongoing proceedings involving SFPP's North and Oregon Line rates;

▪ FERC Docket Nos. OR03-5, OR05-4 and OR05-5—Complainants/Protestants: BP WCP; ExxonMobil; and ConocoPhillips (other shippers intervened)—Defendant: SFPP
Complaints allege that SFPP's interstate rates are not just and reasonable. The FERC has set the complaints against the West and East Line rates for hearing, but denied the request to consolidate the dockets with the ongoing proceedings involving SFPP's North and Oregon Line rates;

▪ FERC Docket No. OR03-5-001—Complainants/Protestants: BP WCP; ExxonMobil; and ConocoPhillips (other shippers intervened)—Defendant: SFPP
The FERC severed the portions of the complaints in Docket Nos. OR03-5, OR05-4, and OR05-5 regarding SFPP's North and Oregon Line rates into a separate proceeding in Docket No. OR03-5-001. A hearing was held in May 2008 and an initial decision is expected in September of 2008;

▪ FERC Docket No. OR07-1—Complainant/Protestant: Tesoro—Defendant: SFPP
Complaint alleges that SFPP's North Line rates are not just and reasonable. Complaint held in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy;

▪ FERC Docket No. OR07-2—Complainant/Protestant: Tesoro—Defendant: SFPP
Complaint alleges that SFPP's West Line rates are not just and reasonable. Complaint held in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy. A request that the FERC set the complaint for hearing – which SFPP opposed – is pending before the FERC;

▪ FERC Docket No. OR07-3—Complainants/Protestants: BP WCP; Chevron; ExxonMobil; Tesoro; and Valero Marketing—Defendant: SFPP
Complaint alleges that SFPP's North Line indexed rate increase was not just and reasonable. The FERC has dismissed the complaint and denied rehearing of the dismissal. Petitions for review filed by BP WCP and ExxonMobil at the D.C. Court. On July 8, 2008, the FERC filed an unopposed motion to hold this proceeding in abeyance pending the D.C. Court's ruling in the Tesoro review proceeding related to Docket No. OR07-16. The D.C. Court has not yet ruled upon this motion;

▪ FERC Docket No. OR07-4—Complainants/Protestants: BP WCP; Chevron; and ExxonMobil—Defendants: SFPP; Kinder Morgan G.P., Inc.; and Knight Inc.
Complaint alleges that SFPP's rates are not just and reasonable. Complaint held in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy. Complainants have withdrawn the portions of the complaint directed to SFPP's affiliates;

▪ FERC Docket Nos. OR07-5 and OR07-7 (consolidated)—Complainants/Protestants: ExxonMobil and Tesoro—Defendants: Calnev; Kinder Morgan G.P., Inc.; and Knight Inc.
Complaints allege that none of Calnev's current rates are just or reasonable. On July 19, 2007, the FERC accepted and held in abeyance the portion of the complaints against the non-grandfathered portion of Calnev's rates, dismissed with prejudice the complaints against Calnev's affiliates, and allowed complainants to file amended complaints regarding the grandfathered portion of Calnev's rates. ExxonMobil filed a request for rehearing of the dismissal of the complaints against Calnev's affiliates, which is currently pending before the FERC. Following a FERC decision in December 2007, ExxonMobil and Tesoro filed amended complaints in these dockets, which Calnev answered. The FERC has not acted on the amended complaints. Calnev and ExxonMobil have reached an agreement in principle to settle this and other dockets. On April 18, 2008, ExxonMobil filed a notice withdrawing its complaint in Docket No. OR07-5 and its motion to intervene in Docket No. OR07-7;

▪ FERC Docket No. OR07-6—Complainant/Protestant: ConocoPhillips—Defendant: SFPP
Complaint alleges that SFPP's North Line indexed rate increase was not just and reasonable. The FERC dismissed the complaints in Docket Nos. OR07-3 and OR07-6 in a single order, without consolidating the

complaints, and denied the request for rehearing of the dismissal filed in Docket No. OR07-3. Although the FERC orders in these dockets have been appealed by certain of the complainants in Docket No. OR07-3, they were not appealed by ConocoPhillips in Docket No. OR07-6. The FERC's decision in Docket No. OR07-6 is now final;

▪ FERC Docket No. OR07-8 (consolidated with Docket No. OR07-11)—Complainant/Protestant: BP WCP—Defendant: SFPP
Complaint alleges that SFPP's 2005 indexed rate increase was not just and reasonable. On June 6, 2007, the FERC dismissed challenges to SFPP's underlying rate but held in abeyance the portion of the Complaint addressing SFPP's July 1, 2005 index-based rate increases. SFPP requested rehearing on July 6, 2007, which the FERC denied. On February 13, 2008, the FERC set this complaint for hearing, but referred it to settlement negotiations which are ongoing. It is consolidated with the complaint in Docket No. OR07-11. The parties have reached an agreement in principle and expect to file an offer of settlement in the near future;

▪ FERC Docket No. OR07-9—Complainant/Protestant: BP WCP—Defendant: SFPP
Complaint alleges that SFPP's ultra low sulphur diesel (ULSD) recovery fee violates the filed rate doctrine and that, in any event, the recovery fee is unjust and unreasonable. On July 6, 2007, the FERC dismissed the complaint. BP WCP requested rehearing, which the FERC denied. A petition for review was filed by BP WCP, which was dismissed by the D.C. Court on March 17, 2008;

▪ FERC Docket No. OR07-11 (consolidated with Docket No. OR07-8)—Complainant/Protestant: ExxonMobil—Defendant: SFPP
Complaint alleges that SFPP's 2005 indexed rate increase was not just and reasonable. On February 13, 2008, the FERC set this complaint for hearing, but referred it to settlement negotiations which are ongoing. It is consolidated with the complaint in Docket No. OR07-8. The parties have reached an agreement in principle and expect to file an offer of settlement in the near future;

▪ FERC Docket No. OR07-14—Complainants/Protestants: BP WCP and Chevron—Defendants: SFPP; Calnev, and several affiliates
Complaint alleges violations of the Interstate Commerce Act and FERC's cash management regulations, seeks review of the FERC Form 6 annual reports of SFPP and Calnev, and again requests interim refunds and reparations. The FERC dismissed the complaints, but directed SFPP and Calnev to review their cash management agreements and records to confirm compliance with FERC requirements and to make corrections, if necessary;

▪ FERC Docket No. OR07-16—Complainant/Protestant: Tesoro—Defendant: Calnev
Complaint challenges Calnev's 2005, 2006, and 2007 indexing adjustments. The FERC dismissed the complaint. A petition for review was filed by Tesoro and the case is in briefing phase before the D.C. Court;

▪ FERC Docket No. OR07-18—Complainants/Protestants: Airline Complainants; Chevron; and Valero Marketing—Defendant: Calnev
Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. In December 2007, the FERC issued an order accepting and holding in abeyance the portion of the complaint against the non-grandfathered portion of Calnev's rates. The order also gave complainants 45 days to amend their complaint against the grandfathered portion of Calnev's rates in light of clarifications provided in the FERC's order. The FERC has not acted on the amended complaint;

▪ FERC Docket No. OR07-19—Complainant/Protestant: ConocoPhillips—Defendant: Calnev
Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. In December 2007, the FERC issued an order accepting and holding in abeyance the portion of the complaint against the non-grandfathered portion of Calnev's rates. The order also gave complainant 45 days to amend its complaint against the grandfathered portion of Calnev's rates in light of clarifications provided in the FERC's order. The FERC has not acted on the amended complaint;

- FERC Docket No. OR07-20—Complainant/Protestant: BP WCP—Defendant: SFPP
  Complaint alleges that SFPP's 2007 indexed rate increase was not just and reasonable. The FERC dismissed the complaint and complainant filed a request for rehearing. Prior to a FERC ruling on the request for rehearing, the parties reached a settlement. In February 2008, FERC accepted a joint offer of settlement that dismissed, with prejudice, the East Line index rate portion of the complaint in OR07-20 for the period from June 1, 2006 through and to November 30, 2007. Petition for review filed by BP WCP at the D.C. Court;

- FERC Docket No. OR07-22—Complainant/Protestant: BP WCP—Defendant: Calnev
  Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. In December 2007, the FERC issued an order giving complainant 45 days to amend its complaint in light of guidance provided by the FERC. The FERC has not acted on the amended complaint;

- FERC Docket No. IS05-230 (North Line rate case)—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed to increase North Line rates to reflect increased costs due to installation of new pipe between Concord and Sacramento, California. Various shippers protested. Administrative law judge's decision pending before the FERC on exceptions. On August 31, 2007, BP WCP and ExxonMobil filed a motion to reopen the record on the issue of SFPP's appropriate rate of return on equity, which SFPP answered on September 18, 2007. On May 2, 2008, the FERC issued an order reopening the record in Docket No. IS05-230 for a paper hearing on issues related to rate of return on equity in light of the FERC's policy statement issued in April of 2008 regarding the methodology for determining returns on equity. The parties have reached a settlement regarding the sole issue of the numeric value of the rate of return on equity to be applied in this proceeding that, upon approval by the FERC, would obviate the need for the paper hearing;

- FERC Docket No. IS05-327—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Various shippers protested, but the FERC determined that the tariff filings were consistent with its regulations. The FERC denied rehearing. The D.C. Court dismissed a petition for review, citing a lack of jurisdiction to review a decision by FERC not to order an investigation;

- FERC Docket No. IS06-283 (East Line rate case)—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed to increase East Line rates to reflect increased costs due to installation of new pipe between El Paso, Texas and Tucson, Arizona. Various shippers protested. In November 2007, the parties submitted a joint offer of settlement which was certified to the FERC in December 2007. In February 2008, as clarified in April 2008, the FERC accepted the joint offer of settlement which, among other things, resolved all protests and complaints related to the East Line Phase I Expansion Tariff. SFPP made the payments to the parties to the settlement on April 8, 2008 and certified to the FERC that such payments were made on April 9, 2008;

- FERC Docket No. IS06-296—Complainant/Protestant: ExxonMobil—Defendant: Calnev
  Calnev increased its interstate rates pursuant to the FERC's indexing methodology. ExxonMobil protested the indexing adjustment, and the FERC set the proceeding for investigation and hearing. Calnev filed a motion to dismiss that is currently pending before the FERC. This proceeding is currently in abeyance pending ongoing settlement discussions. Calnev and ExxonMobil have reached an agreement in principle to settle this and other dockets. On April 18, 2008, ExxonMobil filed a notice withdrawing its protest in Docket No. IS06-296;

- FERC Docket No. IS06-356—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Various shippers protested, but the FERC found the tariff filings consistent with its regulations. The FERC has rescinded the index increase for the East Line rates, and SFPP has requested rehearing. The D.C. Court dismissed a petition for review, citing the rehearing request pending before the FERC. On September 20, 2007, the FERC denied SFPP's request for rehearing. In November 2007, all parties submitted a joint offer of settlement. In February 2008, the FERC accepted the joint offer of settlement which, among other things, resolved all protests and complaints related to the East Line 2006 Index Tariff. SFPP made the payments to the parties to the settlement on April 8, 2008 and certified to the FERC that such payments were made on April 9, 2008;

- FERC Docket No. IS07-137 (Ultra Low Sulfur Diesel (ULSD) surcharge)—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed tariffs reflecting a ULSD recovery fee on diesel products and a ULSD litigation surcharge, and various shippers protested the tariffs. The FERC accepted, subject to refund, the ULSD recovery fee, rejected the ULSD litigation surcharge, and held the proceeding in abeyance pending resolution of other proceedings involving SFPP. Chevron and Tesoro filed requests for rehearing, which the FERC denied by operation of law. BP WCP petitioned the D.C. Court for review of the FERC's denial, the FERC filed a motion to dismiss, and the D.C. Court granted the FERC's motion. In May 2008, the FERC set this proceeding for hearing and held the proceeding in abeyance pending ongoing settlement negotiations;

- FERC Docket No. IS07-229—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: SFPP
  SFPP filed to increase certain rates on its pipelines pursuant to the FERC's indexing methodology. Two shippers filed protests. The FERC found the tariff filings consistent with its regulations but suspended the increased rates subject to refund pending challenges to SFPP's underlying rates. In November 2007, all parties submitted a joint offer of settlement. In February 2008, the FERC accepted the joint offer of settlement which, among other things, resolved all protests and complaints related to the East Line 2007 Index Tariff. In April 2008, SFPP certified payments under the settlement agreement;

- FERC Docket No. IS07-234—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: Calnev
  Calnev filed to increase certain rates on its pipeline pursuant to FERC's indexing methodology. Two shippers protested. The FERC found the tariff filings consistent with its regulations but suspended the increased rates subject to refund pending challenges to SFPP's underlying rates. Calnev and ExxonMobil have reached an agreement in principle to settle this and other dockets. On April 18, 2008, ExxonMobil filed a notice withdrawing its protest in Docket No. IS07-234;

- FERC Docket No. IS08-28—Complainants/Protestants: ConocoPhillips; Chevron; BP WCP; ExxonMobil; Southwest Airlines; Western; and Valero—Defendant: SFPP
  SFPP filed to increase its East Line rates based on costs incurred related to an expansion. Various shippers filed protests, which SFPP answered. The FERC issued an order on November 29, 2007 accepting and suspending the tariff subject to refund. The proceeding is being held in abeyance pursuant to ongoing settlement negotiations. Docket No. IS08-389 has been consolidated with this proceeding;

- FERC Docket No. IS08-302—Complainants/Protestants: Chevron; BP WCP; ExxonMobil; and Tesoro—Defendant: SFPP
  SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Certain shippers protested. The FERC found the tariff filings consistent with its regulations but suspended the increased rates subject to refund (except for the Oregon Line rate) pending challenges to SFPP's underlying rates;

- FERC Docket No. IS08-389—Complainants/Protestants: ConocoPhillips, Valero, Southwest Airlines Co., Navajo, Western—Defendant: SFPP
  SFPP filed to decrease rates on its East Line. In July of 2008, various shippers protested, claiming that the rates should have been further decreased. On July 29, 2008, the FERC accepted and suspended the tariff, subject to refund, to become effective August 1, 2008, consolidated the proceeding with Docket No. IS08-28, and held in abeyance further action pending the outcome of settlement negotiations;

- FERC Docket No. IS08-390—Complainants/Protestants: BP WCP, ExxonMobil, ConocoPhillips, Valero, Chevron, the Airlines—Defendant: SFPP
  SFPP filed to increase rates on its West Line. In July of 2008, various shippers protested, claiming that the rates are unjust and unreasonable. On July 29, 2008, the FERC suspended the tariffs, to become effective August 1, 2008, subject to refund, established a hearing, and held the hearing in abeyance pending the outcome of settlement negotiations; and

- Motions to compel payment of interim damages (various dockets)—Complainants/Protestants: Shippers—Defendants: SFPP; Kinder Morgan G.P., Inc.; and Knight Inc.
  Motions seek payment of interim refunds or escrow of funds pending resolution of various complaints and protests involving SFPP. The FERC denied shippers' refund requests in an order issued on December 26, 2007 in Docket Nos. OR92-8, *et al*. On March 19, 2008, ConocoPhillips and Tosco filed a Motion for Interim Refund and Reparations Order. SFPP filed a response on April 3, 2008. The FERC has yet to act on the parties' motion.

In December 2005, SFPP received a FERC order in Docket Nos. OR92-8, *et al*. and OR96-2, *et al*. that directed it to submit compliance filings and revised tariffs. In accordance with the FERC's December 2005 order and its February 2006 order on rehearing, SFPP submitted a compliance filing to the FERC in March 2006, and rate reductions were implemented on May 1, 2006.

In December 2007, as a follow-up to the March 2006 compliance filing, SFPP received a FERC order that directed it to submit revised compliance filings and revised tariffs. In conjunction with this order, our other FERC and California Public Utilities Commission rate cases, and other unrelated litigation matters, we increased our litigation reserves by $140.0 million in the fourth quarter of 2007. 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 2008. In accordance with FERC's December 2007 order and its February 2008 order on rehearing, SFPP submitted a compliance filing to FERC in February 2008, and further rate reductions were implemented on March 1, 2008. We estimate that the impact of the new rates on our 2008 budget will be less than $3.0 million.

In the second quarter of 2008, SFPP and Calnev made combined settlement payments to various shippers totaling approximately $6.9 million and in general, if the shippers are successful in proving their claims, they are entitled to reparations or refunds of any excess tariffs or rates paid during the two year period prior to the filing of their complaint, and SFPP and Calnev may be required to reduce the amount of their tariffs or rates for particular services. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. Based on our review of these FERC proceedings, we estimate that as of June 30, 2008, shippers are seeking approximately $267 million in reparation and refund payments and approximately $45 million in additional annual rate reductions.

California Public Utilities Commission Proceedings

On April 7, 1997, ARCO, Mobil and Texaco filed a complaint against SFPP with the California Public Utilities Commission, referred to in this note as the CPUC. The complaint challenges rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and requests prospective rate adjustments and refunds with respect to previously untariffed charges for certain pipeline transportation and related services.

In October 2002, the CPUC issued a resolution, referred to in this note as the Power Surcharge Resolution, approving a 2001 request by SFPP to raise its California rates to reflect increased power costs. The resolution approving the requested rate increase also required SFPP to submit cost data for 2001, 2002, and 2003, and to assist the CPUC in determining whether SFPP's overall rates for California intrastate transportation services are reasonable. The resolution reserves the right to require refunds, from the date of issuance of the resolution, to the extent the CPUC's analysis of cost data to be submitted by SFPP demonstrates that SFPP's California jurisdictional rates are unreasonable in any fashion.

On December 26, 2006, Tesoro filed a complaint challenging the reasonableness of SFPP's intrastate rates for the three-year period from December 2003 through December 2006 and requesting approximately $8 million in reparations. As a result of previous SFPP rate filings and related protests, the rates that are the subject of the Tesoro complaint are being collected subject to refund.

SFPP also has various, pending ratemaking matters before the CPUC that are unrelated to the above-referenced complaints and the Power Surcharge Resolution. Protests to these rate increase applications have been filed by various shippers. As a consequence of the protests, the related rate increases are being collected subject to refund.

All of the above matters have been consolidated and assigned to a single administrative law judge. At the time of this report, it is unknown when a decision from the CPUC regarding the CPUC complaints and the Power Surcharge Resolution will be received. No schedule has been established for hearing and resolution of the consolidated proceedings other than the 1997 CPUC complaint and the Power Surcharge Resolution. 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.

On June 6, 2008, as required by CPUC order, SFPP and Calnev Pipe Line Company filed separate general rate case applications, neither of which request a change in existing pipeline rates and both of which assert that existing pipeline rates are reasonable. No action has been taken by the CPUC with respect to either of these filings.

Carbon Dioxide Litigation

Shores and First State Bank of Denton Lawsuits

Kinder Morgan CO_2 Company, L.P. (referred to in this note as Kinder Morgan CO_2), Kinder Morgan G.P., Inc., and Cortez Pipeline Company were among the named defendants in Shores, et al. v. Mobil Oil Corp., et al., No. GC-99-01184 (Statutory Probate Court, Denton County, Texas filed December 22, 1999) and First State Bank of Denton, et al. v. Mobil Oil Corp., et al., No. 8552-01 (Statutory Probate Court, Denton County, Texas filed March 29, 2001). These cases were originally filed as class actions on behalf of classes of overriding royalty interest owners (Shores) and royalty interest owners (Bank of Denton) for damages relating to alleged underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit. On February 22, 2005, the trial judge dismissed both cases for lack of jurisdiction. Some of the individual plaintiffs in these cases re-filed their claims in new lawsuits (discussed below).

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

Kinder Morgan CO_2, 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. 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.

Effective March 5, 2007, all defendants and plaintiffs Bridwell Oil Company, the Alicia Bowdle Trust, and the Estate of Margaret Bridwell Bowdle executed a final settlement agreement which provides for the dismissal of these plaintiffs' claims with prejudice to being refiled. On June 10, 2007, the Houston federal district court entered an order of partial dismissal by which the claims by and against the settling plaintiffs were dismissed with prejudice. The claims asserted by Bailey, Ptasynski, and Gray are not included within the settlement or the order of partial dismissal. Effective April 8, 2008, the Shell and Kinder Morgan defendants and plaintiff Gray entered into an indemnification agreement that provides for the dismissal of Gray's claims with prejudice.

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

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 plaintiff in the arbitration is an entity that was formed as part of the settlement for the purpose of monitoring compliance with the obligations imposed by the settlement agreement. The plaintiff 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 plaintiff 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. Defendants denied that there was any breach of the settlement agreement. On August 7, 2006, the arbitration panel issued its opinion finding that defendants did not breach the settlement agreement. On October 25, 2006, the defendants filed an application to confirm the arbitration decision in New Mexico federal district court. 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 plaintiff initiated a second arbitration (CO2 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 October 11, 2007, the defendants filed a Complaint for Declaratory Judgment and Injunctive Relief in federal district court in New Mexico. The Complaint seeks dismissal of the second arbitration on the basis of res judicata. In November 2007, the plaintiff in the arbitration moved to dismiss the defendants' Complaint on the grounds that the issues presented should be decided by a panel in a second arbitration. In December 2007, the defendants in the arbitration filed a motion seeking summary judgment on their Complaint and dismissal of the second arbitration. On May 16, 2008, the federal district court in New Mexico granted the plaintiff's motion to dismiss. On June 2, 2008, the defendants in the arbitration filed a motion in the New Mexico federal district court seeking an order confirming that the panel in the first arbitration can preside over the second arbitration. On June 3, 2008, the plaintiff filed a request with the American Arbitration Association seeking administration of the arbitration.

MMS Notice of Noncompliance and Civil Penalty

On December 20, 2006, Kinder Morgan CO_2 received a "Notice of Noncompliance and Civil Penalty: Knowing or Willful Submission of False, Inaccurate, or Misleading Information—Kinder Morgan CO_2 Company, L.P., Case No. CP07-001" from the U.S. Department of the Interior, Minerals Management Service, referred to in this note as the MMS. This Notice, and the MMS's position that Kinder Morgan CO_2 has violated certain reporting obligations, relates to a disagreement between the MMS and Kinder Morgan CO_2 concerning the approved transportation allowance to be used in valuing McElmo Dome carbon dioxide for purposes of calculating federal royalties. The Notice of Noncompliance and Civil Penalty assesses a civil penalty of approximately $2.2 million as of December 15, 2006 (based on a penalty of $500.00 per day for each of 17 alleged violations) for Kinder Morgan CO_2's alleged submission of false, inaccurate, or misleading information relating to the transportation allowance, and federal royalties for CO_2 produced at McElmo Dome, during the period from June 2005 through October 2006. The MMS contends that false, inaccurate, or misleading information was submitted in the 17 monthly Form 2014s containing remittance advice reflecting the royalty payments for the referenced period because they reflected Kinder Morgan CO_2's use of the Cortez Pipeline tariff as the transportation allowance. The MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO_2 should have used its "reasonable actual costs" calculated in accordance with certain federal product valuation regulations as amended effective June 1, 2005. The MMS stated that civil penalties will continue to accrue at the same rate until the alleged violations are corrected.

The MMS set a due date of January 20, 2007 for Kinder Morgan CO_2's payment of the approximately $2.2 million in civil penalties, with interest to accrue daily on that amount in the event payment is not made by such date. Kinder Morgan CO_2 has not paid the penalty. On January 2, 2007, Kinder Morgan CO_2 submitted a response to the Notice of Noncompliance and Civil Penalty challenging the assessment in the Office of Hearings and Appeals of the Department of the Interior. On February 1, 2007, Kinder Morgan CO_2 filed a petition to stay the accrual of penalties until the dispute is resolved. On February 22, 2007, an administrative law judge of the U.S. Department of the Interior issued an order denying Kinder Morgan CO_2's petition to stay the accrual of penalties. A hearing on the

Notice of Noncompliance and Civil Penalty was originally set for December 10, 2007. In November 2007, the MMS and Kinder Morgan CO_2 filed a joint motion to vacate the hearing date and stay the accrual of additional penalties to allow the parties to discuss settlement. In November 2007, the administrative law judge granted the joint motion, stayed accrual of additional penalties for the period from November 6, 2007 to February 18, 2008, and reset the hearing date to March 24, 2008. The parties conducted settlement conferences on February 4, 2008 and February 12, 2008. On February 14, 2008, the parties filed a joint motion seeking to vacate the March 24, 2008 hearing and to stay the accrual of additional penalties to allow the parties to continue their settlement discussions. On March 4, 2008, the administrative law judge granted the joint motion. The matter remains continued pending the parties' settlement discussions.

Kinder Morgan CO_2 disputes the Notice of Noncompliance and Civil Penalty and believes that it has meritorious defenses. Kinder Morgan CO_2 contends that use of the Cortez Pipeline tariff as the transportation allowance for purposes of calculating federal royalties was approved by the MMS in 1984. This approval was later affirmed as open-ended by the Interior Board of Land Appeals in the 1990s. Accordingly, Kinder Morgan CO_2 has stated to the MMS that its use of the Cortez tariff as the approved federal transportation allowance is authorized and proper. Kinder Morgan CO_2 also disputes the allegation that it has knowingly or willfully submitted false, inaccurate, or misleading information to the MMS. Kinder Morgan CO_2's use of the Cortez Pipeline tariff as the approved federal transportation allowance has been the subject of extensive discussion between the parties. The MMS was, and is, fully apprised of that fact and of the royalty valuation and payment process followed by Kinder Morgan CO_2 generally.

MMS Order to Report and Pay

On March 20, 2007, Kinder Morgan CO_2 received an "Order to Report and Pay" from the MMS. The MMS contends that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties in the amount of approximately $4.6 million for the period from January 1, 2005 through December 31, 2006 as a result of its use of the Cortez Pipeline tariff as the transportation allowance in calculating federal royalties. As noted in the discussion of the Notice of Noncompliance and Civil Penalty proceeding, the MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO_2 must use its "reasonable actual costs" calculated in accordance with certain federal product valuation regulations. The MMS set a due date of April 13, 2007 for Kinder Morgan CO_2's payment of the $4.6 million in claimed additional royalties, with possible late payment charges and civil penalties for failure to pay the assessed amount. Kinder Morgan CO_2 has not paid the $4.6 million, and on April 19, 2007, it submitted a notice of appeal and statement of reasons in response to the Order to Report and Pay, challenging the Order and appealing it to the Director of the MMS in accordance with 30 C.F.R. sec. 290.100, et seq. Also on April 19, 2007, Kinder Morgan CO_2 submitted a petition to suspend compliance with the Order to Report and Pay pending the appeal. The MMS granted Kinder Morgan CO_2's petition to suspend, and approved self-bonding on June 12, 2007. Kinder Morgan CO_2 filed a supplemental statement of reasons in support of its appeal of the Order to Report and Pay on June 15, 2007.

In addition to the March 2007 Order to Report and Pay, in April 2007, Kinder Morgan CO_2 received an "Audit Issue Letter" sent by the Colorado Department of Revenue on behalf of the U.S. Department of the Interior. In the letter, the Department of Revenue states that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties (due to the use of the Cortez Pipeline tariff as the transportation allowance for purposes of federal royalties) in the amount of $8.5 million for the period from April 2000 through December 2004. Kinder Morgan CO_2 responded to the letter in May 2007, outlining its position why use of the Cortez tariff-based transportation allowance is proper. On August 8, 2007, Kinder Morgan CO_2 received an "Order to Report and Pay Additional Royalties" from the MMS. As alleged in the Colorado Audit Issue Letter, the MMS contends that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties in the amount of approximately $8.5 million for the period from April 2000 through December 2004. The MMS's claims underlying the August 2007 Order to Report and Pay are similar to those at issue in the March 2007 Order to Report and Pay. On September 7, 2007, Kinder Morgan CO_2 submitted a notice of appeal and statement of reasons in response to the August 2007 Order to Report and Pay, challenging the Order and appealing it to the Director of the MMS in accordance with 30 C.F.R. sec. 290.100, et seq. Also on September 7, 2007, Kinder Morgan CO_2 submitted a petition to suspend compliance with the Order to Report and Pay pending the appeal. The MMS granted Kinder Morgan CO_2's petition to suspend, and approved self-bonding on September 11, 2007.

The MMS and Kinder Morgan CO_2 have agreed to stay the March 2007 and August 2007 Order to Report and Pay proceedings to allow the parties to discuss settlement. The parties conducted settlement conferences on February 4, 2008 and February 12, 2008 and continue to engage in settlement discussions.

Kinder Morgan CO_2 disputes both the March and August 2007 Orders to Report and Pay and the Colorado Department of Revenue Audit Issue Letter, and as noted above, it contends that use of the Cortez Pipeline tariff as the transportation allowance for purposes of calculating federal royalties was approved by the MMS in 1984 and was affirmed as open-ended by the Interior Board of Land Appeals in the 1990s. The appeals to the MMS Director of the Orders to Report and Pay do not provide for an oral hearing. No further submission or briefing deadlines have been set.

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 (8^{th} 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 ("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 plaintiffs allege that they were members of a class previously certified as a class action by the United States District Court for the District of New Mexico in the matter Doris Feerer, et al. v. Amoco Production Company, et al., USDC N.M. Civ. No. 95-0012 (the "Feerer Class Action"). Plaintiffs allege that Kinder Morgan CO_2's method of paying royalty interests is contrary to the settlement of the Feerer Class Action. Kinder Morgan CO_2 filed a motion to compel arbitration of this matter pursuant to the arbitration provisions contained in the Feerer Class Action settlement agreement, which motion was denied. Kinder Morgan CO_2 appealed this decision to the New Mexico Court of Appeals, which affirmed the decision of the trial court. The New Mexico Supreme Court granted further review in October 2006, and after hearing oral argument, the New Mexico Supreme Court quashed its prior order granting review. In August 2007, Kinder Morgan CO_2 filed a petition for writ of certiorari with the United States Supreme Court seeking further review. The Petition was denied in December 2007. The case is now proceeding in the trial court as a certified class action and the case is set for trial in September 2008.

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 and the States of Colorado and New Mexico.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP, L.P. 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 in the first quarter 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. SFPP believes that it must pay for relocation of the pipeline only when so required by the railroad's common carrier operations, and in doing so, it need only comply with standards set forth in the federal Pipeline Safety Act in conducting 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 we must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP has appealed this decision. In addition, UPRR contends that it has complete discretion to cause the pipeline to be relocated at SFPP's expense at any time and for any reason, and that SFPP must comply with the more expensive American Railway Engineering and Maintenance-of-Way standards. Each party is seeking declaratory relief with respect to its positions regarding 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 has appealed this Order to the Tenth Circuit Court of Appeals. The oral argument is expected to take place in September 2008.

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. On April 24, 2007 the Court held a hearing on the Motions to Dismiss and for Sanctions and the Requests for Attorney Fees. A decision is still pending on the Motions to Dismiss and for Sanctions and the Requests for Attorney Fees.

Weldon Johnson and Guy Sparks, individually and as Representative of Others Similarly Situated v. Centerpoint Energy, Inc. et. al., No. 04-327-2 (Circuit Court, Miller County Arkansas).

On October 8, 2004, plaintiffs filed the above-captioned matter against numerous defendants including Kinder Morgan Texas Pipeline L.P.; Kinder Morgan Energy Partners, L.P.; Kinder Morgan G.P., Inc.; KM Texas Pipeline, L.P.; Kinder Morgan Texas Pipeline G.P., Inc.; Kinder Morgan Tejas Pipeline G.P., Inc.; Kinder Morgan Tejas Pipeline, L.P.; Gulf Energy Marketing, LLC; Tejas Gas, LLC; and MidCon Corp. (the "Kinder Morgan defendants"). The complaint purports to bring a class action on behalf of those who purchased natural gas from the CenterPoint defendants from October 1, 1994 to the date of class certification.

The complaint alleges that CenterPoint Energy, Inc., by and through its affiliates, has artificially inflated the price charged to residential consumers for natural gas that it allegedly purchased from the non-CenterPoint defendants, including the Kinder Morgan defendants. The complaint further alleges that in exchange for CenterPoint's purchase of such natural gas at above market prices, the non-CenterPoint defendants, including the Kinder Morgan defendants, sell natural gas to CenterPoint's non-regulated affiliates at prices substantially below market, which in turn sells such natural gas to commercial and industrial consumers and gas marketers at market price. The complaint purports to assert claims for fraud, unlawful enrichment and civil conspiracy against all of the defendants, and seeks relief in the form of actual, exemplary and punitive damages, interest, and attorneys' fees. On June 8, 2007, the Arkansas Supreme Court held that the Arkansas Public Service Commission has exclusive jurisdiction over any Arkansas plaintiffs' claims that consumers were overcharged for gas in Arkansas and mandated that any such claims be dismissed from this lawsuit. On February 14, 2008, the Arkansas Supreme Court clarified its previously issued order and mandated that the trial court dismiss the lawsuit in its entirety. On February 29, 2008 the trial court dismissed the case in its entirety.

Queen City Railcar Litigation

On August 28, 2005, a railcar containing the chemical styrene began leaking styrene gas in Cincinnati, Ohio while en route to our Queen City Terminal. The railcar was sent by the Westlake Chemical Corporation from Louisiana, transported by Indiana & Ohio Railway, and consigned to Westlake at its dedicated storage tank at Queen City Terminals, Inc., a subsidiary of Kinder Morgan Bulk Terminals, Inc. The railcar leak resulted in the evacuation of many residents and the alleged temporary closure of several businesses in the Cincinnati area. A class action complaint and separate suits by the City of Cincinnati and the Estate of George W. Dameron (who opted out of the class settlement) have been settled without admission of fault or liability.

As part of the settlement of the class action claims, the non-Kinder Morgan defendants agreed to settle remaining claims asserted by businesses and obtain a release of such claims favoring all defendants, including us, subject to the retention by all defendants of their claims against each other for contribution and indemnity. We expect that a claim will be asserted by other defendants against us seeking contribution or indemnity for any settlements funded exclusively by other defendants, and we expect to vigorously defend against any such claims.

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 May 2006, the court granted defendants' motions to dismiss as to the counts purporting to assert claims for fraud, but denied defendants' motions to dismiss as to the remaining counts, as well as defendants' motions to strike portions of the complaint. Defendant Kennametal, Inc. has filed a third-party complaint naming the United States and the United States Navy (the "United States") as additional defendants. In response, the United States removed the case to the United States District Court for the District of Nevada and filed a motion to dismiss the third-party complaint. Plaintiff has also filed a motion to dismiss the United States and/or to remand the case back to state court. By order dated September 25, 2007, the United States District Court granted the motion to dismiss the United States from the case and remanded the Jernee and Sands cases back to the Second Judicial District Court, State of Nevada, County of Washoe. The cases will now proceed in the State Court. Based on the information available to date, our own preliminary investigation, and the positive results of investigations conducted by State and Federal agencies, we believe that the remaining claims against us in these matters are without merit and intend to defend against them vigorously.

Pipeline Integrity and Releases

From time to time, 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.

We believe that we conduct our operations in accordance with applicable law. We seek to cooperate with state and federal regulatory authorities in connection with the clean-up of the environment caused by such leaks and ruptures and with any investigations as to the facts and circumstances surrounding the incidents.

Walnut Creek, California Pipeline Rupture

On November 9, 2004, excavation equipment operated by Mountain Cascade, Inc., a third-party contractor on a water main installation project hired by East Bay Municipal Utility District, struck and ruptured an underground petroleum pipeline owned and operated by SFPP, L.P. in Walnut Creek, California. An explosion occurred immediately following the rupture that resulted in five fatalities and several injuries to employees or contractors of Mountain Cascade. The explosion and fire also caused property damage.

On May 5, 2005, the California Division of Occupational Safety and Health ("CalOSHA") issued two civil citations against us relating to this incident assessing civil fines of approximately $0.1 million based upon our alleged failure to mark the location of the pipeline properly prior to the excavation of the site by the contractor. On March 24, 2008, we agreed to a settlement with CalOSHA by which the two citations would be reduced to two "unclassified" violations of the CalOSHA regulations and we would pay a fine of $140,000. The settlement is currently awaiting approval by the CalOSHA Appeals Board.

On June 27, 2005, the Office of the California State Fire Marshal, Pipeline Safety Division, referred to in this report as the CSFM, issued a notice of violation against us which also alleged that we did not properly mark the location of the pipeline in violation of state and federal regulations. The CSFM assessed a proposed civil penalty of $0.5 million. We have reached an agreement in principle with CSFM to settle the proposed civil penalty for $325,000 with no admission of liability.

As a result of the accident, nineteen separate lawsuits were filed. The majority of the cases were personal injury and wrongful death actions that alleged, among other things, that SFPP/Kinder Morgan failed to properly field mark the area where the accident occurred.

Following court ordered mediation, the Kinder Morgan defendants have settled with plaintiffs in all of the wrongful death cases and the personal injury and property damages cases. The only remaining civil case is a claim for equitable indemnity by an engineering company defendant against Kinder Morgan G.P. Services Co., Inc. We have filed a Motion for Summary Judgment with respect to all of the claims in this matter, which motion is currently pending.

EPA Notice of Proposed Debarment

On August 21, 2007, SFPP received a Notice of Proposed Debarment issued by the United States Environmental Protection Agency, referred to in this report as the EPA. Pursuant to the Notice, the Suspension and Debarment Division, referred to in this report as SDD, of the EPA is proposing to debar SFPP from participation in future Federal contracts and assistance activities for a period of three years. The purported basis for the proposed debarment is SFPP's April 2005 agreement with the California Attorney General and the District Attorney of Solano County, California to settle misdemeanor charges of the unintentional, non-negligent discharge of diesel fuel, and the failure to provide timely notice of a threatened discharge to appropriate state agencies, in connection with the April 28, 2004 spill of diesel fuel into a marsh near Cordelia, California. SFPP believed that the proposed debarment was factually and legally unwarranted and contested it. On June 2, 2008, the EPA SDD agreed to withdraw the Notice of Proposed Debarment and terminated the matter without additional action.

Soda Springs, California

In August 2006, our SFPP pipeline experienced a failure near Soda Springs, California, resulting in a release of product that affected a limited area along Interstate Highway 80. Product impacts were primarily limited to soil in an area between the pipeline and Interstate Highway 80. Remediation and monitoring activities are ongoing under the supervision of the California Department of Fish & Game and Nevada County. The cause of the release was determined to be pinhole corrosion in an unpiggable 2-inch diameter bypass to the mainline valve. The bypass was installed to allow pipeline maintenance activity. The bypass piping was replaced at this location and all other similar designs on the pipeline segment were excavated, evaluated and replaced as necessary to avoid future risk of release. On January 30, 2008, we entered into a settlement agreement with Nevada County and the state of California to resolve any outstanding civil penalties claims related to this release for $75,000.

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, referred to in this note as REX), 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 is under investigation by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to in this report as the PHMSA. In March 2008, PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order ("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, PHMSA has not issued any NOPV's to REX, and we do not expect that it will do so. Immediately following the incident, REX 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, REX and several other parties in the District Court of Harris County, Texas, 189 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, REX and its contractors. We were indemnified for the full amount of this settlement by one of REX's contractors. The parties are currently engaged in discovery on the remaining claims. We do not expect the cost of any settlement or eventual judgment, if any, to be material.

Charlotte, North Carolina

On November 27, 2006, the Plantation Pipeline experienced a release of approximately 4,000 gallons of gasoline from a Plantation Pipe Line Company block valve on a delivery line into a terminal owned by a third party company. Upon discovery of the release, Plantation immediately locked out the delivery of gasoline through that pipe to prevent further releases. Product had flowed onto the surface and into a nearby stream, which is a tributary of Paw Creek, and resulted in loss of fish and other biota. Product recovery and remediation efforts were implemented immediately, including removal of product from the stream. 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 (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.

Although Plantation does not believe that penalties are warranted, it is engaging in settlement discussions with the EPA regarding a potential civil penalty for the November 2006 release as part of broader settlement negotiations with the EPA regarding this spill and two other historic releases from Plantation, including a February 2003 release near Hull, Georgia. Plantation has reached an agreement in principle with the Department of Justice and the EPA for all four releases for approximately $0.7 million, plus some additional work to be performed to prevent future releases. The parties are negotiating a consent decree. Although it is not possible to predict the ultimate outcome, 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.

In addition, 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 an historical turbine fuel release. The groundwater contamination is underneath at least two lots on which there is current construction of single family homes as 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 residential subdivision. 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 has (i) migrated underneath the Navy's Marine Corps Logistics Base in Barstow; (ii) 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 MCLB'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 CERCLA Removal Action to reimburse the Navy for $0.5 million in past response actions, plus perform other work 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 BC Ministry of Environment, the National Energy Board, and the National Transportation Safety Board. Cleanup and environmental remediation is near completion. The incident is currently under investigation by Federal and Provincial agencies. We do not expect this matter to have a material adverse impact on our results of operations or cash flows.

On December 20, 2007 we initiated a lawsuit entitled Trans Mountain Pipeline LP, Trans Mountain Pipeline Inc. and Kinder Morgan Canada Inc. v. The City of Burnaby, et al., Supreme Court of British Columbia, Vancouver Registry No. S078716. The suit alleges that the City of Burnaby and its agents are liable in damages including, but not limited to, all costs and expenses incurred by us as a result of the rupture of the pipeline and subsequent release of crude oil. Defendants have denied liability and discovery has begun.

Although no assurance can be given, we believe that we have meritorious defenses to all pending pipeline integrity 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, 2008, and December 31, 2007, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $219.4 million and $247.9 million, respectively. The reserve is primarily related to various claims from lawsuits arising from our Pacific operations’ 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

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

On April 23, 2003, Exxon Mobil Corporation filed a complaint in the Superior Court of New Jersey, Gloucester County. We filed our answer to the complaint on June 27, 2003, in which we denied ExxonMobil's claims and allegations as well as included counterclaims against ExxonMobil. 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 ST Services, Inc. Prior to selling the terminal to GATX Terminals, ExxonMobil performed the environmental site assessment of the terminal required prior to sale pursuant to state law. During the site assessment, ExxonMobil discovered items that required remediation and the New Jersey Department of Environmental Protection issued an order that required ExxonMobil to perform various remediation activities to remove hydrocarbon contamination at the terminal. ExxonMobil, we understand, is still remediating the site and has not been removed as a responsible party from the state's cleanup order; however, ExxonMobil claims that the remediation continues because of GATX Terminals' storage of a fuel additive, MTBE, at the terminal during GATX Terminals' ownership of the terminal. When GATX Terminals sold the terminal to ST Services, the parties indemnified one another for certain environmental matters. When GATX Terminals was sold to us, GATX Terminals' indemnification obligations, if any, to ST Services may have passed to us. Consequently, at issue is any indemnification obligation we may owe to ST Services for environmental remediation of MTBE at the terminal. The complaint seeks any and all damages related to remediating MTBE 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 for remediating MTBE at the terminal. The parties are currently involved in mandatory mediation and the most recent mediation occurred in June 2008. No progress was made at this latest mediation. The mediation judge is now allowing the parties to conduct limited discovery up to the date of the next mediation which is anticipated to be in October 2008.

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 Exxon Mobil Corporation and GATX Terminals Corporation. The complaint was filed in Gloucester County, New Jersey. Both Exxon Mobil and we filed third party complaints against ST Services seeking to bring ST into the case. ST Services filed motions to dismiss the third party complaints. Recently, the court denied ST's motions to dismiss and ST is now joined in the case. Defendants will now file their answers in the case. 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 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 Exxon Mobil 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 ST Services. ST Services is the current owner and operator at the facility. The court may consolidate the two cases.

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 defendants will soon file an Answer. It is anticipated that the parties will then commence with discovery. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board. We do not expect the cost of any settlement and remediation to be material.

In June 2008, we received an Administrative Civil Liability Complaint from the California Regional Water Quality Control Board for violations and penalties associated with surface water discharge from the remediation system operating at the Mission Valley terminal facility. Currently, we are negotiating a settlement that should include a reduction of alleged violations and associated penalties as well as resolve any past and future issues related to the discharge from the remediation system. We do not expect the cost of the settlement to be material.

Portland Harbor DOJ/EPA Investigation

In April 2008, we reached an agreement in principle with the United States Attorney's office for the District of Oregon and the United States Department of Justice regarding a former employee's involvement in the improper disposal of potash (potassium chloride) into the Pacific Ocean in August 2003 at our Portland, Oregon bulk terminal facility. The incident involved an employee making arrangements to have a customer's shipment of potash, which had become wet and no longer met specifications for commercial use, improperly disposed of at sea without a permit.

We have fully cooperated with the government's investigation and promptly adopted measures at the terminal to avoid future incidents of this nature. To settle the matter, we have agreed in principle to enter a plea to a criminal violation of the Ocean Dumping Act, pay a fine of approximately $0.2 million, and make a community service payment of approximately $0.1 million to the Oregon Governor's Fund for the Environment. As part of the agreement in principle, the government and we acknowledge in a statement of fact to be filed with the court that (i) no harm was done to the environment; (ii) the former employee's actions constituted a violation of company policy; (iii) we did not benefit financially from the incident; and (iv) no personnel outside of the Portland terminal either approved or had any knowledge of the former employee's arrangements.

Louisiana Department of Environmental Quality Settlement

After conducting a voluntary compliance self-audit in April 2006, we voluntarily disclosed certain findings from the audit related to compliance with environmental regulations and permits at our Harvey and St. Gabriel Terminals to the Louisiana Department of Environmental Quality, referred to in this report as the LDEQ. Following further discussion between the LDEQ and us, in August 2007, the LDEQ issued a Consolidated Compliance Order and Notice of Potential Penalty for each of the two facilities. We reached a settlement with LDEQ under which we agreed to finalize certain work, which we have already undertaken to ensure compliance with the environmental regulations at these two facilities, and paid a penalty of $0.3 million. Therefore, the matter is resolved.

Other Environmental

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) generally imposes joint and several liability for cleanup and enforcement costs on current or 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 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 violations will have a material adverse affect 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.

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, 2008, we have accrued an environmental reserve of $88.1 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. As of December 31, 2007, our environmental reserve totaled $92.0 million. 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.

4. Asset Retirement Obligations

According to the provisions of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," we record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

In our CO_2 business segment, we are required to plug and abandon oil and gas wells that have been removed from service and to remove our surface wellhead equipment and compressors. As of June 30, 2008 and December 31, 2007, we have recognized asset retirement obligations in the aggregate amount of $73.5 million and $49.2 million, respectively, relating to these requirements at existing sites within our CO_2 business segment. The $24.3 million increase was primarily related to higher estimated service, material and equipment costs related to our legal obligations associated with the retirement of tangible long-lived assets.

In our Natural Gas Pipelines business segment, if we were to cease providing utility services, we would be required to remove certain surface facilities and equipment from land belonging to our customers and others. We believe we can reasonably estimate both the time and costs associated with the retirement of these facilities and as of June 30, 2008 and December 31, 2007, we have recognized asset retirement obligations in the aggregate amount of $3.8 million and $3.0 million, respectively, relating to the businesses within our Natural Gas Pipelines business segment.

We have included $1.4 million of our total asset retirement obligations as of June 30, 2008 with "Accrued other current liabilities" in our accompanying consolidated balance sheet. The remaining $75.9 million obligation is reported separately as a non-current liability. A reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligations for each of the six months ended June 30, 2008 and 2007 is as follows (in millions):

	Six Months Ended June 30,	
	2008	2007
Balance at beginning of period	$ 52.2	$ 50.3
Liabilities incurred	25.5	0.2
Liabilities settled	(1.8)	(0.3)
Accretion expense	1.4	1.3
Balance at end of period	$ 77.3	$ 51.5

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of-way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain bulk and liquids terminal facilities. An asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

5. Distributions

On May 15, 2008, we paid a cash distribution of $0.96 per unit to our common unitholders and our Class B unitholders for the quarterly period ended March 31, 2008. KMR, our sole i-unitholder, received 1,305,429 additional i-units based on the $0.96 cash distribution per common unit. The distributions were declared on April 16, 2008, payable to unitholders of record as of April 30, 2008.

On July 16, 2008, we declared a cash distribution of $0.99 per unit for the quarterly period ended June 30, 2008. The distribution will be paid on August 14, 2008, to unitholders of record as of July 31, 2008. Our common unitholders and Class B unitholders will receive cash. KMR will receive a distribution of 1,359,152 additional i-units based on the $0.99 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.018124) will be issued. This fraction was determined by dividing:

- $0.99, the cash amount distributed per common unit

by

- $54.625, the average of KMR's shares' closing market prices from July 15-28, 2008, 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.

6. Intangibles

Goodwill

For our investments in affiliated entities that are included in our consolidation, the excess cost over underlying fair value of net assets is referred to as goodwill and reported separately as "Goodwill" in our accompanying consolidated balance sheets. Goodwill is not subject to amortization but must be tested for impairment at least annually. This test requires us to assign goodwill to an appropriate reporting unit and to determine if the implied fair value of the reporting unit's goodwill is less than its carrying amount.

On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from Knight, and this transaction was completed April 30, 2007 (see Note 2). Following the provisions of generally accepted accounting principles, the consideration of this transaction caused Knight to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Based on this determination, Knight recorded a goodwill impairment charge of $377.1 million in the first quarter of 2007, and because we have included all of the historical results of Trans Mountain as though the net assets had been transferred to us on January 1, 2006, this impairment expense is now reflected in our consolidated results of operations.

Changes in the carrying amount of our goodwill for the three months ended March 31, 2008 and six months ended June 30, 2008 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Trans Mountain	Terminals	Total
Balance as of December 31, 2007	$ 263.2	$ 288.4	$ 46.1	$ 251.0	$ 229.1	$ 1,077.8
Acquisitions and purchase price adjs.	—	—	—	—	18.1	18.1
Disposals.	—	—	—	—	—	—
Impairments	—	—	—	—	—	—
Currency translation adjustments	—	—	—	(9.7)	—	(9.7)
Balance as of March 31, 2008	263.2	288.4	46.1	241.3	247.2	1,086.2
Acquisitions and purchase price adjs.	—	—	—	—	1.3	1.3
Disposals.	—	—	—	—	—	—
Impairments	—	—	—	—	—	—
Currency translation adjustments	—	—	—	1.9	—	1.9
Balance as of June 30, 2008	$ 263.2	$ 288.4	$ 46.1	$ 243.2	$ 248.5	$ 1,089.4

Pursuant to our adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" on January 1, 2002, we selected a goodwill impairment measurement date of January 1 of each year; and we have determined that our goodwill was not impaired as of January 1, 2008. In the second quarter of 2008, we changed our impairment measurement date to May 31 of each year. The change was made following our management's decision to match our impairment testing date to the impairment testing date of Knight—following the completion of its going-private transaction on May 30, 2007, Knight established as its goodwill impairment measurement date May 31 of each year. This change to the date of our annual goodwill impairment test constitutes a change in the method of applying an accounting principle, as discussed in paragraph 4 of SFAS No. 154, "Accounting Changes and Error Corrections." We believe that this change in accounting principle is preferable because our test would then be performed at the same time as Knight, the sole indirect common stockholder of our general partner.

SFAS No. 154 requires an entity to report a change in accounting principle through retrospective application of the new accounting principle to all periods, unless it is impracticable to do so. However, our change to a new testing date, when applied to prior periods, does not yield different financial statement results. Furthermore, there were no impairment charges resulting from the May 31, 2008 impairment testing, and no event indicating an impairment has occurred subsequent to that date.

In addition, according to the provisions of Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock," 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 not subject to amortization but rather to periodic impairment testing. As of both June 30, 2008 and December 31, 2007, we have 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, 2008	December 31, 2007
Customer relationships, contracts and agreements		
Gross carrying amount	$ 246.0	$ 264.1
Accumulated amortization	(43.9)	(36.9)
Net carrying amount	202.1	227.2
Technology-based assets, lease value and other		
Gross carrying amount	13.3	13.3
Accumulated amortization	(2.1)	(1.9)
Net carrying amount	11.2	11.4
Total Other intangibles, net	$ 213.3	$ 238.6

For the three and six months ended June 30, 2008, the amortization expense on our intangibles totaled $3.7 million and $7.2 million, respectively, and for the same prior year periods, the amortization expense on our intangibles totaled $3.4 million and $6.8 million, respectively. These expense amounts primarily consisted of amortization of our customer relationships, contracts and agreements. As of June 30, 2008, the weighted average amortization period for our intangible assets was approximately 17.7 years. Our estimated amortization expense for these assets for each of the next five fiscal years (2009 – 2013) is approximately $13.8 million, $13.6 million, $13.4 million, $13.1 million and $13.1 million, respectively.

7. Debt

Our outstanding short-term debt as of June 30, 2008 was $270.9 million. The balance consisted of (i) $250.0 million in principal amount of 6.30% senior notes due February 1, 2009; (ii) a $9.6 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); (iii) a $6.3 million portion of 5.23% senior notes (our subsidiary, Kinder Morgan Texas Pipeline, L.P., is the obligor on the notes); and (iv) a $5.0 million portion of 7.84% senior notes (our subsidiary, Central Florida Pipe Line LLC, is the obligor on the notes). The weighted average interest rate on all of our borrowings was approximately 5.35% during the second quarter of 2008 and approximately 6.41% during the second quarter of 2007.

Credit Facility

Our $1.85 billion five-year unsecured bank credit facility matures August 18, 2010 and can be amended to allow for borrowings up to $2.1 billion. Borrowings under our credit facility can be used for partnership purposes and as a backup for our commercial paper program. There were no borrowings under the credit facility as of June 30, 2008 or as of December 31, 2007.

Our five-year credit facility is with a syndicate of financial institutions and Wachovia Bank, National Association is the administrative agent. As of June 30, 2008, the amount available for borrowing under our credit facility was reduced by an aggregate amount of $929.2 million, consisting of (i) a combined $620 million in three letters of credit that support our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil; (ii) 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; (iii) a combined $92.1 million in three letters of credit that support tax-exempt bonds; (iv) a combined $53.4 million in letters of credit that support our pipeline and terminal operations in Canada; (v) a $26.8 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; (vi) a $19.9 million letter of credit that supports the construction of our Kinder Morgan Louisiana Pipeline (a natural gas pipeline); and (vii) a combined $17 million in other letters of credit supporting other obligations of us and our subsidiaries.

Commercial Paper Program

Our commercial paper program provides for the issuance of up to $1.85 billion of commercial paper. Our $1.85 billion unsecured five-year bank credit facility supports our commercial paper program, and borrowings under our commercial paper program reduce the borrowings allowed under our credit facility. As of June 30, 2008, we had no outstanding commercial paper borrowings. As of December 31, 2007, we had $589.1 million of commercial paper outstanding with an average interest rate of 5.58%. The borrowings under our commercial paper program were used principally to finance the acquisitions and capital expansions we made during 2008 and 2007.

Senior Notes

On February 12, 2008, we completed a public offering of senior notes. We issued a total of $900 million in principal amount of senior notes, consisting of $600 million of 5.95% notes due February 15, 2018, and $300 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $894.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program. The notes due in 2038 constitute a further issuance of the $550 million aggregate principal amount of 6.95% notes we issued on June 21, 2007 and form a single series with those notes.

On June 6, 2008, we completed an additional public offering of senior notes. We issued a total of $700 million in principal amount of senior notes, consisting of $375 million of 5.95% notes due February 15, 2018, and $325 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $687.7 million, and we used the proceeds to reduce the borrowings under our commercial paper program. The notes due in 2018 constitute a further issuance of the $600 million aggregate principal amount of 5.95% notes we issued on February 12, 2008 and form a single series with those notes. The notes due in 2038 constitute a further issuance of the combined $850 million aggregate principal amount of 6.95% notes we issued on June 21, 2007 and February 12, 2008, respectively, and form a single series with those notes.

Kinder Morgan Operating L.P. "A" Debt

As part of the purchase price consideration for our January 1, 2007 acquisition of the remaining approximate 50.2% interest in the Cochin pipeline system that we did not already own, 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%. The principal amount of the note, along with interest, is due in five equal annual installments of $10.0 million on March 31 in each of 2008, 2009, 2010, 2011 and 2012. Our subsidiaries Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company are the obligors on the note, and as of June 30, 2008 and December 31, 2007, the outstanding balance under the note was $35.6 million and $44.6 million, respectively.

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 10.

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, 2008.

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, 2008, the debt facilities of Cortez Capital Corporation consisted of (i) $53.6 million of Series D notes due May 15, 2013; (ii) a $125 million short-term commercial paper program; and (iii) a $125 million five-year committed revolving credit facility due December 22, 2009 (to support the above-mentioned $125 million commercial paper program). As of June 30, 2008, Cortez Capital Corporation had $111.4 million of commercial paper outstanding with an average interest rate of approximately 3.07%, the average interest rate on the Series D notes was 7.14%, and there were no borrowings under the credit facility.

With respect to Cortez's Series D notes, 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, 2008, JP Morgan Chase has issued a letter of credit on our behalf in the amount of $26.8 million to secure our indemnification obligations to Shell for 50% of the $53.6 million in principal amount of Series D notes outstanding as of June 30, 2008.

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, 2008, this letter of credit had a face amount of $22.5 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 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 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. 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%; however, upon issuance of the notes, Rockies Express entered into two floating-to-fixed interest rate swap agreements having a combined notional principal amount of $600 million and maturity dates of August 20, 2009. The interest rate swap agreements effectively convert the interest expense associated with these senior notes from its stated variable rate to a fixed rate of 5.85%.

As of June 30, 2008, in addition to the $600 million in floating rate senior notes, Rockies Express Pipeline LLC had $740.4 million of commercial paper outstanding ($512.6 million net of cash on hand) with a weighted average interest rate of approximately 3.0%, and there were no borrowings under its five-year credit facility. Accordingly, as of June 30, 2008, our contingent share of Rockies Express' debt was $683.6 million (51% of total guaranteed borrowings). In addition, there is a letter of credit outstanding to support the construction of the Rockies Express Pipeline. The combined face amount for this letter of credit, issued by JPMorgan Chase, was $31.4 million as of June 30, 2008; our contingent responsibility with regard to this outstanding letter of credit was $16.0 million (51% of total face amount).

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 agreement will be used to finance the construction of the Midcontinent Express Pipeline system and to pay related expenses.

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, 2008, Midcontinent Express Pipeline LLC had $385.0 million borrowed under its three-year credit facility. Accordingly, as of June 30, 2008, our contingent share of Midcontinent Express' debt was $192.5 million (50% of total borrowings).

In addition, Midcontinent Express Pipeline LLC has a $197 million reimbursement agreement dated September 4, 2007, with JPMorgan Chase as the administrative agent. The agreement includes covenants and requires payments of fees that are common in such arrangements, and both we and Energy Transfer Partners, L.P. have agreed to guarantee borrowings under the reimbursement agreement in the same proportion as the associated percentage ownership of our member interests. Furthermore, both the reimbursement agreement and the revolving 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, 2008, existing letters of credit having a combined face amount of $205.7 million were issued. The total face amount for the letters of credit consisted of (i) $172.4 million from two separate letters of credit under the revolving credit facility; and (ii) $33.3 million under a single letter of credit under the reimbursement agreement. Accordingly, as of June 30, 2008, our contingent responsibility with regard to these outstanding letters of credit was $102.9 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 2007 Form 10-K.

8. Partners' Capital

Limited Partner Units

As of June 30, 2008 and December 31, 2007, our partners' capital included the following limited partner units:

	June 30, 2008	December 31, 2007
Common units	177,054,734	170,220,396
Class B units	5,313,400	5,313,400
i-units	74,991,862	72,432,482
Total limited partner units	257,359,996	247,966,278

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

As of June 30, 2008, our total common units consisted of 162,698,999 units held by third parties, 12,631,735 units held by Knight and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner. As of December 31, 2007, our common unit total consisted of 155,864,661 units held by third parties, 12,631,735 units held by Knight and its consolidated affiliates (excluding our general partner) and 1,724,000 units held by our general partner.

On both June 30, 2008 and December 31, 2007, all of our 5,313,400 Class B units were held by a wholly-owned subsidiary of Knight. 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 Knight in December 2000.

On both June 30, 2008 and December 31, 2007, all of our i-units were held entirely 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 unit. Based on the preceding, KMR received a distribution of 1,305,429 i-units from us on May 15, 2008, based on the $0.96 per unit distributed to our common unitholders on that date.

Equity Issuances

On February 12, 2008, we completed an offering of 1,080,000 of our common units at a price of $55.65 per unit in a privately negotiated transaction. We received net proceeds of $60.1 million for the issuance of these 1,080,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

In addition, on March 3, 2008, we issued, in a public offering, 5,000,000 of our common units at a price of $57.70 per unit, less commissions and underwriting expenses. At the time of the offering, we granted the underwriters a 30-day option to purchase up to an additional 750,000 common units from us on the same terms and conditions, and pursuant to this option, we issued an additional 750,000 common units on March 10, 2008 upon exercise of this option. After commissions and underwriting expenses, we received net proceeds of $324.2 million for the issuance of these 5,750,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

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.

Incentive distributions allocated to our general partner are determined by the amount quarterly distributions to unitholders exceed certain specified target levels. Our distribution of $0.96 per unit paid on May 15, 2008 for the first quarter of 2008 required an incentive distribution to our general partner of $185.8 million. Our distribution of $0.83 per unit paid on May 15, 2007 for the first quarter of 2007 resulted in an incentive distribution payment to our general partner in the amount of $138.8 million. The increased incentive distribution to our general partner paid for the first and second quarter of 2008 over the incentive distribution paid for the first and second quarter of 2007 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 2008 of $0.99 per unit will result in an incentive distribution to our general partner of $194.2 million. This compares to our distribution of $0.85 per unit and incentive distribution to our general partner of $147.6 million for the second quarter of 2007.

9. Comprehensive Income

Comprehensive income is the change in our Partners' Capital that results from periodic revenues, expenses, gains and losses, as well as any other recognized changes that occur for reasons other than investments by and distributions to our partners. The difference between our comprehensive income and our net income represents our other comprehensive income.

For each of the three and six month periods ended June 30, 2008 and 2007, the components of our other comprehensive included (i) unrealized gains or losses on energy commodity derivative contracts utilized for hedging purposes; (ii) foreign currency translation adjustments; and (iii) unrealized gains or losses related to changes in pension and other post-retirement benefit plan liabilities.

Our total comprehensive income (loss) was as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Net Income:	$ 362.2	$ 232.7	$ 708.9	$ 83.2
Other comprehensive income (loss):				
Change in fair value of derivative contracts utilized for hedging purposes	(1,648.7)	(125.9)	(2,051.5)	(226.9)
Reclassification of change in fair value of derivative contracts to net income	261.8	95.7	422.6	164.1
Foreign currency translation adjustments	11.2	45.1	(43.4)	51.7
Adjustments to pension and other post-retirement benefit plan actuarial gains/losses; and reclassifications of pension and other post-retirement benefit plan actuarial gains/losses, transition obligations and prior service costs/credits to net income, net of tax	(0.1)	(0.3)	3.4	1.1
Total other comprehensive income (loss)	(1,375.8)	14.6	(1,668.9)	(10.0)
Comprehensive income (loss)	$ (1,013.6)	$ 247.3	$ (960.0)	$ 73.2

10. Risk Management

Energy Commodity Price Risk Management

We are exposed to risks associated with unfavorable changes in the market price of natural gas, natural gas liquids and crude oil as a result of our expected future purchase or sale of these products. Such changes are often caused by shifts in the supply and demand for these commodities, as well as their locations. 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.

Discontinuance of Hedge Accounting

Effective at the beginning of the second quarter of 2008, we determined that the derivative contracts of our Casper and Douglas gas processing operations that previously had been designated as cash flow hedges for accounting purposes no longer met the hedged item shared risk exposure requirement and hedge effectiveness assessment as required by SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Consequently, we discontinued hedge accounting treatment for these relationships (primarily crude oil hedges of heavy natural gas liquids sales) for financial reporting purposes at that time.

Pursuant to the provisions of SFAS No. 133, if a derivative contract accounted for as a cash flow hedge is discontinued because it is probable that the original forecasted transaction will not occur, any gains and losses on the derivative contracts that are included in accumulated other comprehensive income (an equity account) would be recognized immediately in net income; however, when the variability of future cash flows of the hedged item will occur as expected (as future transactions), gains and losses that are accumulated in other comprehensive income are not affected. The reason for continuing the deferral of the derivative gains and losses is that the risk of the variability of future cash flows of the hedged item is not eliminated when the cash flow hedge is discontinued.

Accordingly, since the forecasted sales of natural gas liquids volumes (the hedged item) are still expected to occur, all of our accumulated gains and losses through March 31, 2008 on the related derivative contracts remained in our accumulated other comprehensive income balance, and these gains and losses will not be reclassified into our earnings until the physical transaction occurs (similar to our accounting before our de-designation of these derivative contracts as hedge instruments). We did, however, recognize an incremental expense of $13.1 million in the second quarter of 2008 related to our Casper and Douglas processing operations, due to the fact that we had discontinued hedge accounting for these derivatives as of March 31, 2008 and accordingly were required to immediately recognize the unfavorable differential between (i) the delivery location, commodity and pricing specifications of the derivative contracts; and (ii) the delivery location, commodity and pricing specifications of our previously forecasted natural gas liquids sales.

Hedging effectiveness and ineffectiveness

Reflecting the portion of changes in the value of derivative contracts that were not effective in offsetting underlying changes in expected cash flows (the ineffective portion of hedges), we recognized a loss of $2.4 million during the first quarter of 2008, but no gains or losses from ineffective hedging during the second quarter of 2008. For the three and six months ended June 30, 2007, we recognized ineffective hedging gains of $0.3 million and $0.9 million, respectively. These recognized gains and losses resulting from hedge ineffectiveness are reported within the captions "Natural gas sales," "Gas purchases and other costs of sales," and "Product sales and other" in our accompanying consolidated statements of income, and for each of the first six months of 2008 and 2007, we did not exclude any component of the derivative contracts' gain or loss from the assessment of hedge effectiveness. Additionally, basis swaps may also be used in connection with another derivative to reduce hedge ineffectiveness by reducing a basis difference between a hedged exposure and a derivative.

Furthermore, during the three and six month periods ended June 30, 2008, we reclassified $261.8 million and $422.6 million, respectively, of "Accumulated other comprehensive loss" into earnings, and for the same comparable periods last year, we reclassified $95.7 million and $164.1 million, respectively into earnings. Included in the first quarter of 2007 is approximately $0.1 million resulting from the discontinuance of cash flow hedges due to a determination that the forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter. All remaining amounts reclassified into net income during the first half of both years resulted from the hedged forecasted transactions actually affecting earnings (for example, when the forecasted sales and purchases actually occurred). 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 $2,945.5 million as of June 30, 2008, and $1,276.6 million as of December 31, 2007. These consolidated totals included "Accumulated other comprehensive loss" amounts associated with commodity price risk management activities of $3,006.2 million as of June 30, 2008 and $1,377.2 million as of December 31, 2007. Approximately $1,091.8 million of the total amount associated with our commodity price risk management activities as of June 30, 2008 is expected to be reclassified into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur).

Fair Value of Energy Commodity Derivative Contracts

The fair values of our energy commodity derivative contracts are included in our accompanying consolidated balance sheets within "Other current assets," "Deferred charges and other assets," "Accrued other current liabilities," and "Other long-term liabilities and deferred credits." The following table summarizes the fair values of our energy commodity derivative contracts associated with our commodity price risk management activities and included on our accompanying consolidated balance sheets as of June 30, 2008 and December 31, 2007 (in millions):

	June 30, 2008	December 31, 2007
Derivatives-net asset/(liability)		
Other current assets	$ 77.7	$ 37.0
Deferred charges and other assets	37.3	4.4
Accrued other current liabilities	(1,191.4)	(593.9)
Other long-term liabilities and deferred credits	$ (1,974.5)	$ (836.8)

As discussed in our financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2007, we have counterparty credit risk as a result of our use of financial derivative contracts. In addition, 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, 2008 and December 31, 2007, we had three outstanding letters of credit totaling $620.0 million and $298.0 million, respectively, in support of our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil. Additionally, as of June 30, 2008 and December 31, 2007, we had cash margin deposits associated with our commodity contract positions and over-the-counter swap partners totaling $275.0 million and $67.9 million, respectively, and we reported these amounts as “Restricted deposits” in our accompanying consolidated balance sheets.

Additional information on the fair value measurements of our energy commodity derivative contracts is included below in “—SFAS No. 157.”

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 floating 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.

As of December 31, 2007, we were a party to interest rate swap agreements with a total notional principal amount of $2.3 billion. On February 12, 2008, following our issuance of $600 million of 5.95% senior notes on that date, we entered into two additional fixed-to-floating interest rate swap agreements having a combined notional principal amount of $500 million; and on June 6, 2008, following our issuance of $700 million in principal amount of senior notes in two separate series on that date (discussed in Note 7), we entered into two additional fixed-to-floating interest rate swap agreements having a combined notional principal amount of $700 million.

Therefore, as of June 30, 2008, we had a combined notional principal amount of $3.5 billion of fixed-to-floating 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, 2008, 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.

Hedging effectiveness and ineffectiveness

Our interest rate swap contracts have been designated as fair value hedges and meet the conditions required to assume no ineffectiveness under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.” Therefore, we have accounted for them using the “shortcut” method prescribed by SFAS No. 133 and accordingly, we adjust the carrying value of each swap contract to its fair value each quarter, with an offsetting entry to adjust the carrying value of the debt securities whose fair value is being hedged. We record interest expense equal to the variable rate payments under the swap contracts.

Fair Value of Interest Rate Swap Agreements

The differences between the fair value and the original carrying value associated with our interest rate swap agreements, that is, the derivative contracts' changes in fair value, are included within "Deferred charges and other assets" and "Other long-term liabilities and deferred credits" in our accompanying consolidated balance sheets. 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, 2008, this unamortized premium totaled $14.0 million.

The following table summarizes the net fair value of our interest rate swap agreements associated with our interest rate risk management activities and included on our accompanying consolidated balance sheets as of June 30, 2008 and December 31, 2007 (in millions):

	June 30, 2008	December 31, 2007
Derivatives-net asset/(liability)		
Deferred charges and other assets	$ 158.9	$ 138.0
Other long-term liabilities and deferred credits	(30.0)	—
Net fair value of interest rate swaps	$ 128.9	$ 138.0

Furthermore, we are exposed to credit related losses in the event of nonperformance by counterparties to our interest rate swap agreements, and while we enter into derivative contracts primarily with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk. As of June 30, 2008, all of our interest rate swap agreements were with counterparties with investment grade credit ratings.

Additional information on the fair value measurements of our interest rate swap agreements is included below in "—SFAS No. 157."

SFAS No. 157

On September 15, 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." In general, fair value measurements and disclosures are made in accordance with the provisions of this Statement and, 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 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 have not applied 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, although the fair value measurements we have made in these circumstances are not necessarily different from those that would be made had the provisions of SFAS No. 157 been applied. We adopted the remainder of SFAS No. 157 effective January 1, 2008, and the adoption did not have a material impact on our balance sheet, statement of income, or statement of cash flows since we already apply its basic concepts in measuring fair values.

The degree of judgment utilized in measuring the fair value of financial instruments generally correlates to the level of pricing observability. Pricing observability is affected by a number of factors, including the type of financial instrument, whether the financial instrument is new to the market and the characteristics specific to the transaction. Financial instruments with readily available active quoted prices or for which fair value can be measured from actively quoted prices generally will have a higher degree of pricing observability and a lesser degree of judgment utilized in measuring fair value. Conversely, financial instruments rarely traded or not quoted will generally have less (or no) pricing observability and a higher degree of judgment utilized in measuring fair value.

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).

Derivative contracts can be exchange-traded or over-the-counter, referred to in this report as OTC. Exchange-traded derivative contracts typically fall within Level 1 of the fair value hierarchy if they are traded in an active market. We value exchange-traded derivative contracts using quoted market prices for identical securities.

OTC derivative contracts are valued using models utilizing a variety of inputs including contractual terms; commodity, interest rate and foreign currency curves; and measures of volatility. The selection of a particular model and particular inputs to value an OTC derivative contract depends upon the contractual terms of the instrument as well as the availability of pricing information in the market. We use similar models to value similar instruments. For OTC derivative contracts that trade in liquid markets, such as generic forwards and swaps, model inputs can generally be verified and model selection does not involve significant management judgment. Such contracts are typically classified within Level 2 of the fair value hierarchy.

Certain OTC derivative contracts trade in less liquid markets with limited pricing information, and the determination of fair value for these derivative contracts is inherently more difficult. Such contracts are classified within Level 3 of the fair value hierarchy. The valuations of these less liquid OTC derivative contracts are typically impacted by Level 1 and/or Level 2 inputs that can be observed in the market, as well as unobservable Level 3 inputs. Use of a different valuation model or different valuation input values could produce a significantly different estimate of fair value. However, derivative contracts valued using inputs unobservable in active markets are generally not material to our financial statements.

When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management's best estimate is used.

The following tables summarize the fair value measurements of our (i) energy commodity derivative contracts; and (ii) interest rate swap agreements as of June 30, 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 as of June 30, 2008 Using			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivative contracts (a)	$ 115.0	$ —	$ 79.1	$ 35.9
Interest rate swap agreements	158.9	—	158.9	—

	Liability Fair Value Measurements as of June 30, 2008 Using			
	Total	Quoted Prices in Active Markets for Identical Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivative contracts (b)	$ (3,165.9)	$ (6.7)	$ (2,890.3)	$ (268.9)
Interest rate swap agreements	(30.0)	—	(30.0)	—

(a) Level 2 consists primarily of OTC West Texas Intermediate hedges. Level 3 consists primarily of West Texas Sour hedges 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. Level 3 consists primarily of West Texas Sour hedges 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, 2008 (in millions):

Significant Unobservable Inputs (Level 3)	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008
Derivatives-net asset/(liability)		
Beginning of Period	$ (123.8)	$ (100.3)
Realized and unrealized net losses	(141.5)	(186.3)
Purchases and settlements	32.3	53.6
Transfers in (out) of Level 3	—	—
End of Period	(233.0)	(233.0)
Change in unrealized net losses relating to contracts still held as of June 30, 2008	$ (123.1)	$ (160.8)

Other

Additionally, certain of our business activities expose us to foreign currency fluctuations. However, due to the limited size of this exposure, we do not believe the risks associated with changes in foreign currency will have a material adverse effect on our business, financial position, results of operations or cash flows. As a result, we do not significantly hedge our exposure to fluctuations in foreign currency.

For a more complete discussion of our risk management activities, see Note 14 to our consolidated financial statements included in our 2007 Form 10-K.

11. Reportable Segments

We divide our operations into five reportable business segments:

- Products Pipelines;
- Natural Gas Pipelines;

- CO_2;
- Terminals; and
- Trans Mountain.

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 minority interest but net of income tax expense. 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.

Our Products Pipelines segment derives its revenues primarily from the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids. Our Natural Gas Pipelines segment derives its revenues primarily from the sale, transport, processing, treating, storage and gathering of natural gas. Our CO_2 segment derives its revenues primarily from the production and sale of crude oil from fields in the Permian Basin of West Texas and from the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields. Our Terminals segment derives its revenues primarily from 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. Our Trans Mountain business segment derives its revenues primarily from the transportation of crude oil and refined products from Edmonton, Alberta to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State.

As discussed in Note 2, due to the October 2007 sale of our North System, an approximate 1,600-mile interstate common carrier pipeline system whose operating results were included as part of our Products Pipelines business segment, we accounted for the North System business as a discontinued operation. Consistent with the management approach of identifying and reporting discrete financial information on operating segments, we have included the North System's financial results within our Products Pipelines business segment disclosures presented in this report for the first six months of 2007 and, as prescribed by SFAS No. 131, we have reconciled the total of our reportable segment's financial results to our consolidated financial results by separately identifying, in the following pages where applicable, the North System amounts as discontinued operations.

Financial information by segment follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Revenues				
Products Pipelines				
Revenues from external customers	$ 198.6	$ 215.1	$ 396.9	$ 425.4
Intersegment revenues	—	—	—	—
Natural Gas Pipelines				
Revenues from external customers	2,644.7	1,693.1	4,557.2	3,228.5
Intersegment revenues	—	—	—	—
CO_2				
Revenues from external customers	308.6	199.5	595.0	391.1
Intersegment revenues	—	—	—	—
Terminals				
Revenues from external customers	300.4	228.8	580.4	443.7
Intersegment revenues	0.3	0.2	0.5	0.4
Trans Mountain				
Revenues from external customers	43.4	43.3	86.5	76.1
Intersegment revenues	—	—	—	—
Total segment revenues	3,496.0	2,380.0	6,216.5	4,565.2
Less: Total intersegment revenues	(0.3)	(0.2)	(0.5)	(0.4)
	3,495.7	2,379.8	6,216.0	4,564.8
Less: Discontinued operations	—	(13.4)	—	(26.7)
Total consolidated revenues	$ 3,495.7	$ 2,366.4	$ 6,216.0	$ 4,538.1

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Operating expenses(a)				
Products Pipelines	$ 68.5	$ 77.8	$ 130.9	$ 150.2
Natural Gas Pipelines	2,515.6	1,555.4	4,260.7	2,961.1
CO_2	96.6	76.2	187.3	146.8
Terminals	156.0	117.1	308.8	232.9
Trans Mountain	17.0	16.0	32.7	27.9
Total segment operating expenses	2,853.7	1,842.5	4,920.4	3,518.9
Less: Total intersegment operating expenses	(0.3)	(0.2)	(0.5)	(0.4)
	2,853.4	1,842.3	4,919.9	3,518.5
Less: Discontinued operations	—	(6.2)	—	(10.7)
Total consolidated operating expenses	$ 2,853.4	$ 1,836.1	$ 4,919.9	$ 3,507.8
Other expense (income)				
Products Pipelines	$ (0.6)	$ (2.8)	$ (1.0)	$ (2.3)
Natural Gas Pipelines	(2.7)	(2.7)	(2.7)	(2.7)
CO_2	—	—	—	—
Terminals	0.2	(1.7)	(0.4)	(4.4)
Trans Mountain(b)	—	—	—	377.1
Total segment other expense (income)	(3.1)	(7.2)	(4.1)	367.7
Less: Discontinued operations	0.8	—	1.3	—
Total consolidated other expense (income)	$ (2.3)	$ (7.2)	$ (2.8)	$ 367.7
Depreciation, depletion and amortization				
Products Pipelines	$ 22.3	$ 22.2	$ 44.5	$ 44.8
Natural Gas Pipelines	16.8	16.2	33.5	32.2
CO_2	88.1	71.2	170.7	140.1
Terminals	30.8	21.2	59.9	41.7
Trans Mountain	7.6	5.0	15.1	9.7
Total segment depreciation, depletion and amortization	165.6	135.8	323.7	268.5
Less: Discontinued operations	—	(2.3)	—	(4.7)
Total consol. depreciation, depletion and amortization	$ 165.6	$ 133.5	$ 323.7	$ 263.8
Earnings from equity investments				
Products Pipelines	$ 8.7	$ 9.0	$ 16.2	$ 16.4
Natural Gas Pipelines	31.3	3.8	54.8	10.2
CO_2	5.5	5.0	11.1	10.2
Terminals	0.7	—	1.7	—
Trans Mountain	—	—	0.1	—
Total segment earnings from equity investments	46.2	17.8	83.9	36.8
Less: Discontinued operations	—	(0.5)	—	(1.2)
Total consolidated equity earnings	$ 46.2	$ 17.3	$ 83.9	$ 35.6
Amortization of excess cost of equity investments				
Products Pipelines	$ 0.9	$ 0.8	$ 1.7	$ 1.6
Natural Gas Pipelines	0.1	0.2	0.2	0.3
CO_2	0.5	0.5	1.0	1.0
Terminals	—	—	—	—
Trans Mountain	—	—	—	—
Total segment amortization of excess cost of investments	1.5	1.5	2.9	2.9
Less: Discontinued operations	—	—	—	—
Total consol. amortization of excess cost of investments	$ 1.5	$ 1.5	$ 2.9	$ 2.9
Interest income				
Products Pipelines	$ 1.1	$ 1.1	$ 2.1	$ 2.2
Natural Gas Pipelines	—	—	—	—
CO_2	—	—	—	—
Terminals	—	—	—	—
Trans Mountain	—	—	—	—
Total segment interest income	1.1	1.1	2.1	2.2
Unallocated interest income	0.1	0.3	0.4	0.5
Total consolidated interest income	$ 1.2	$ 1.4	$ 2.5	$ 2.7

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Other, net – income (expense)				
Products Pipelines	$ 0.2	$ 3.0	$ (0.3)	$ 3.1
Natural Gas Pipelines	17.7	0.2	17.9	0.2
CO_2	—	—	(0.2)	—
Terminals	1.4	—	2.7	—
Trans Mountain	4.0	0.6	6.1	1.1
Total segment other, net – income (expense)	23.3	3.8	26.2	4.4
Less: Discontinued operations	—	—	—	—
Total consolidated other, net – income (expense)	$ 23.3	$ 3.8	$ 26.2	$ 4.4
Income tax benefit (expense)				
Products Pipelines	$ (3.1)	$ (5.6)	$ (6.7)	$ (8.4)
Natural Gas Pipelines	1.7	0.2	(1.2)	(1.2)
CO_2	(0.9)	0.6	(2.2)	(0.2)
Terminals	(6.2)	(3.5)	(10.7)	(5.0)
Trans Mountain	3.0	1.7	3.6	(0.8)
Total segment income tax benefit (expense)	(5.5)	(6.6)	(17.2)	(15.6)
Unallocated income tax benefit (expense)	(4.4)	—	(4.4)	—
Total consolidated income tax benefit (expense)	$ (9.9)	$ (6.6)	$ (21.6)	$ (15.6)
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(c)				
Products Pipelines	$ 137.6	$ 147.6	$ 278.3	$ 290.8
Natural Gas Pipelines	182.5	144.6	370.7	279.3
CO_2	216.6	128.9	416.4	254.3
Terminals	140.4	110.1	266.2	210.6
Trans Mountain	33.4	29.6	63.6	(328.6)
Total segment earnings before DD&A	710.5	560.8	1,395.2	706.4
Total segment depreciation, depletion and amortization	(165.6)	(135.8)	(323.7)	(268.5)
Total segment amortization of excess cost of investments	(1.5)	(1.5)	(2.9)	(2.9)
Interest and corporate administrative expenses(d)	(181.2)	(190.8)	(359.7)	(351.8)
Total consolidated net income	$ 362.2	$ 232.7	$ 708.9	$ 83.2
Capital expenditures				
Products Pipelines	$ 63.5	$ 66.5	$ 120.8	$ 102.8
Natural Gas Pipelines	229.1	72.2	416.8	99.1
CO_2	153.4	72.1	248.4	161.7
Terminals	94.6	119.2	240.6	211.8
Trans Mountain	93.9	64.7	236.0	115.0
Total consolidated capital expenditures(e)	$ 634.5	$ 394.7	$ 1,262.6	$ 690.4

	June 30, 2008	December 31, 2007
Assets		
Products Pipelines	$ 4,110.8	$ 4,045.0
Natural Gas Pipelines	5,454.3	4,347.3
CO_2	2,238.0	2,004.5
Terminals	3,210.3	3,036.4
Trans Mountain	1,577.7	1,440.8
Total segment assets	16,591.1	14,874.0
Corporate assets(f)	557.9	303.8
Total consolidated assets	$ 17,149.0	$ 15,177.8

(a) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, fuel and power expenses and taxes, other than income taxes.
(b) Six month 2007 amount represents an expense of $377.1 million attributable to a goodwill impairment charge recognized by Knight, as discussed in Notes 2 and 6.
(c) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).
(d) Includes unallocated interest income and income tax expense, interest and debt expense, general and administrative expenses (including unallocated litigation and environmental expenses) and minority interest expense.

(e) Sustaining capital expenditures, including our share of Rockies Express' sustaining capital expenditures, totaled $46.9 million for the second quarter of 2008, $36.4 million for the second quarter of 2007, $76.8 million for the first six months of 2008 and $63.2 million for the first six months of 2007. These listed amounts do not include sustaining capital expenditures for Trans Mountain for any periods prior to our acquisition date of April 30, 2007. Sustaining capital expenditures are defined as capital expenditures which do not increase the capacity of an asset.

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

We do not attribute interest and debt expense to any of our reportable business segments. For the three months ended June 30, 2008 and 2007, we reported total consolidated interest expense of $100.0 million and $98.5 million, respectively. For the six months ended June 30, 2008 and 2007, we reported total consolidated interest expense of $198.0 million and $190.6 million, respectively.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Revenues from external customers				
United States	$ 3,429.4	$ 2,309.4	$ 6,087.1	$ 4,439.7
Canada	60.7	52.4	117.9	89.0
Mexico and other(a)	5.6	4.6	11.0	9.4
Total consolidated revenues from external customers	$ 3,495.7	$ 2,366.4	$ 6,216.0	$ 4,538.1

	June 30, 2008	December 31, 2007
Long-lived assets(b)		
United States	$ 12,093.6	$ 11,054.3
Canada	1,603.0	1,420.0
Mexico and other(a)	89.1	89.5
Total consolidated long-lived assets	$ 13,785.7	$ 12,563.8

(a) Includes operations in Mexico and the Netherlands.

(b) Long-lived assets exclude (i) goodwill; (ii) other intangibles, net; and (iii) long-term note receivables from related parties.

12. Pensions and Other Post-Retirement Benefits

Due to our acquisition of Trans Mountain (see Note 2), Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.) are sponsors of pension and other post-retirement benefit plans for eligible Trans Mountain employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. We also provide post-retirement benefits other than pensions for retired employees. Our combined net periodic benefit costs for these Trans Mountain pension and post-retirement benefit plans for the first six months of 2008 and 2007 were approximately $1.5 million and $1.6 million, respectively. As of June 30, 2008, we estimate our overall net periodic pension and post-retirement benefit costs for these plans for the year 2008 will be approximately $3.1 million, recognized ratably over the year, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. We expect to contribute approximately $2.6 million to these benefit plans in 2008.

Additionally, in connection with our acquisition of SFPP, L.P. and Kinder Morgan Bulk Terminals, Inc. in 1998, we acquired certain liabilities for pension and post-retirement benefits. We provide medical and life insurance benefits to current employees, their covered dependents and beneficiaries of SFPP and Kinder Morgan Bulk Terminals. We also provide the same benefits to former salaried employees of SFPP. Additionally, we will continue to fund these costs for those employees currently in the plan during their retirement years. SFPP's post-retirement benefit plan is frozen and no additional participants may join the plan.

As of June 30, 2008, we estimate no overall net periodic post-retirement benefit cost for the SFPP post-retirement benefit plan for the year 2008; however, this estimate could change if a future significant event would require a remeasurement of liabilities. For the first six months of 2007, our net periodic benefit cost for the SFPP post-retirement benefit plan was a credit of approximately $0.1 million. The credit resulted in increases to income, largely due to amortizations of an actuarial gain and a negative prior service cost. In addition, we expect to contribute approximately $0.4 million to this post-retirement benefit plan in 2008.

The noncontributory defined benefit pension plan covering the former employees of Kinder Morgan Bulk Terminals is the Knight Inc. Retirement Plan. The benefits under this plan are based primarily upon years of service and final average pensionable earnings; however, benefit accruals were frozen as of December 31, 1998.

13. Related Party Transactions

Plantation Pipe Line Company Note Receivable

We have a seven-year note receivable bearing interest at the rate of 4.72% per annum from Plantation Pipe Line Company, our 51.17%-owned equity investee. The outstanding note receivable balance was $88.5 million as of June 30, 2008, and $89.7 million as of December 31, 2007. Of these amounts, $2.5 million and $2.4 million were included within "Accounts, notes and interest receivable, net—Related parties," as of June 30, 2008 and December 31, 2007, respectively, and the remainder was included within "Notes receivable—Related parties" at each reporting date.

Knight Asset Contributions

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

Knight Note Receivable

As of June 30, 2008 and December 31, 2007, an affiliate of Knight owed to us a long-term note with a principal amount of $0.3 million and $0.6 million, respectively, and we included this balance within "Notes receivable—Related parties" on our consolidated balance sheet at each reporting date. This note currently has no fixed terms of repayment and is denominated in Canadian dollars. The above amounts represent the translated amounts included in our consolidated financial statements in U.S. dollars.

Fair Value of Energy Commodity Derivative Contracts

As a result of the May 2007 going-private transaction of Knight, as discussed in Note 1, a number of individuals and entities became significant investors in Knight. By virtue of the size of their ownership interest in Knight, 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, 2008 and December 31, 2007 (in millions):

	June 30, 2008	December 31, 2007
Derivatives-net asset/(liability)		
Deferred charges and other assets	$ 7.8	$ —
Accrued other current liabilities	(566.7)	(239.8)
Other long-term liabilities and deferred credits	$ (1,154.5)	$ (386.5)

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 and is its sole managing member. Knight, 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, Knight 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 Knight 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 Annual Report on 2007 Form 10-K.

14. Regulatory Matters

The following updates the disclosure in Note 17 to our audited financial statements that were filed with our 2007 Form 10-K with respect to developments that occurred during the three months ended June 30, 2008.

FERC Order No. 2004/690

Since November 2003, the FERC issued Orders No. 2004, 2004-A, 2004-B, 2004-C, and 2004-D, adopting new Standards of Conduct as applied to natural gas pipelines. The primary change from existing regulation was to make such standards applicable to an interstate natural gas pipeline's interaction with many more affiliates (referred to as "energy affiliates"). The Standards of Conduct require, among other things, separate staffing of interstate pipelines and their energy affiliates (but support functions and senior management at the central corporate level may be shared) and strict limitations on communications from an interstate pipeline to an energy affiliate.

However, on November 17, 2006, the United States Court of Appeals for the District of Columbia Circuit, in Docket No. 04-1183, vacated FERC Orders 2004, 2004-A, 2004-B, 2004-C, and 2004-D as applied to natural gas pipelines, and remanded these same orders back to the FERC.

On January 9, 2007, the FERC issued an Interim Rule, effective January 9, 2007, in response to the court's action. In the Interim Rule, the FERC readopted the Standards of Conduct, but revised or clarified with respect to issues which had been appealed to the court. Specifically, the following changes were made:

- the Standards of Conduct apply only to the relationship between interstate gas transmission pipelines and their marketing affiliates, not their energy affiliates;

- all risk management personnel can be shared;

- the requirement to post discretionary tariff actions was eliminated (but interstate gas pipelines must still maintain a log of discretionary tariff waivers);

- lawyers providing legal advice may be shared employees; and

▪ new interstate gas transmission pipelines are not subject to the Standards of Conduct until they commence service.

The FERC clarified that all exemptions and waivers issued under Order No. 2004 remain in effect. On January 18, 2007, the FERC issued a notice of proposed rulemaking seeking comments regarding whether or not the Interim Rule should be made permanent for natural gas transmission providers ("January 18 NOPR"). On March 21, 2007, FERC issued an Order on Clarification and Rehearing of the Interim Rule that granted clarification that the Standards of Conduct only apply to natural gas transmission providers that are affiliated with a marketing or brokering entity that conducts transportation transactions on such gas transmission provider's pipeline.

On March 21, 2008, as part of an effort to undertake a broader review of the existing Standards of Conduct, the FERC issued a new notice of proposed rulemaking revamping the Standards of Conduct in order to make compliance and enforcement easier, rather than issuing a Final Rule on the January 18 NOPR. The intent of this action is to return to the core principles of the original Standards of Conduct, which established a functional separation between transmission and merchant personnel for natural gas and electric transmission providers. The new NOPR is made up of three rules: independent functioning of transmission function employees from marketing function employees, the no-conduit rule prohibiting the passing and receipt of non-public transmission information, and the transparency rule to detect undue discrimination. Comments on the revised NOPR were filed by numerous parties on May 12, 2008.

Notice of Inquiry – Financial Reporting

On February 15, 2007, the FERC issued a notice of inquiry seeking comment on the need for changes or revisions to the FERC's reporting requirements contained in the financial forms for gas and oil pipelines and electric utilities. Initial comments were filed by numerous parties on March 27, 2007, and reply comments were filed on April 27, 2007.

On September 20, 2007, the FERC issued for public comment in Docket No. RM07-9 a proposed rule which would revise its financial forms to require that additional information be reported by natural gas companies. The proposed rule would require, among other things, that natural gas companies: (i) submit additional revenue information, including revenue from shipper-supplied gas; (ii) identify the costs associated with affiliate transactions; and (iii) provide additional information on incremental facilities and on discounted and negotiated rates. The FERC proposes an effective date of January 1, 2008, which means that forms reflecting the new requirements for 2008 would be filed in early 2009. Comments on the proposed rule were filed by numerous parties on November 13, 2007.

On March 21, 2008 the FERC issued a Final Rule regarding changes to the Form 2, 2-A and 3Q. The revisions were designed to enhance the forms' usefulness by updating them to reflect current market and cost information relevant to interstate pipelines and their customers. The rule is effective January 1, 2008 with the filing of the revised Form 3-Q beginning with the first quarter of 2009. The revised Form 2 and 2-A for calendar year 2008 material would be filed by April 30, 2009. On June 20, 2008, the FERC issued an Order Granting in Part and Denying in Part Rehearing and Granting Request for Clarification. No substantive changes were made to the March 21, 2008 Final Rule.

Notice of Inquiry – Fuel Retention Practices

On September 20, 2007, the FERC issued a Notice of Inquiry seeking comment on whether it should change its current policy and prescribe a uniform method for all interstate gas pipelines to use in recovering fuel gas and gas lost and unaccounted for. The Notice of Inquiry included numerous questions regarding fuel recovery issues and the effects of fixed fuel percentages as compared with tracking provisions. Comments on the Notice of Inquiry were filed by numerous parties on November 30, 2007.

Notice of Proposed Rulemaking – Promotion of a More Efficient Capacity Release Market

On November 15, 2007, the FERC issued a notice of proposed rulemaking in Docket No. RM 08-1-000 regarding proposed modifications to its Part 284 regulations concerning the release of firm capacity by shippers on interstate natural gas pipelines. The FERC proposes to remove, on a permanent basis, the rate ceiling on capacity release transactions of one year or less. Additionally, the FERC proposes to exempt capacity releases made as part of an asset management arrangement from the prohibition on tying and from the bidding requirements of section 284.8. Initial comments were filed by numerous parties on January 25, 2008. On June 19, 2008, the FERC issued a final rule regarding changes to the capacity release program. The FERC permitted market based pricing for short-term capacity releases of a year or less. Long-term capacity releases and the pipeline's sale of its own capacity remains subject to a price cap. The ruling would facilitate asset management arrangements by relaxing the FERC's prohibitions on tying and on its bidding requirements for certain capacity releases. The FERC further clarified that its prohibition on tying does not apply to conditions associated with gas inventory held in storage for releases for firm storage capacity. Finally, the FERC waived the prohibition on tying and bidding requirements for capacity releases made as part of state-approved retail open access programs. The final rule became effective on July 30, 2008.

Notice of Proposed Rulemaking – Natural Gas Price Transparency

On April 19, 2007, the FERC issued a notice of proposed rulemaking in Docket Nos. RM07-10-000 and AD06-11-000 regarding price transparency provisions of Section 23 of the Natural Gas Act and the Energy Policy Act. In the notice, the FERC proposed to revise its regulations to (i) require that intrastate pipelines post daily the capacities of, and volumes flowing through, their major receipt and delivery points and mainline segments in order to make available the information to track daily flows of natural gas throughout the United States; and (ii) require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC in order to make possible an estimate of the size of the physical U.S. natural gas market, assess the importance of the use of index pricing in that market, and determine the size of the fixed-price trading market that produces the information. The FERC believes these revisions to its regulations will facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. Initial comments were filed on July 11, 2007 and reply comments were filed on August 23, 2007. In addition, the FERC conducted an informal workshop in this proceeding on July 24, 2007, to discuss implementation and other technical issues associated with the proposals set forth in the NOPR.

In addition, on December 21, 2007, the FERC issued a new notice of proposed rulemaking in Docket No. RM08-2-000 regarding the daily posting provisions that were contained in Docket Nos. RM07-10-000 and AD06-11-000. The new NOPR proposes to exempt from the daily posting requirements those non-interstate pipelines that (i) flow less than 10 million MMBtus of natural gas per year, (ii) fall entirely upstream of a processing plant, and (iii) deliver more than ninety-five percent (95%) of the natural gas volumes they flow directly to end-users. However, the new NOPR expands the proposal to require that both interstate and non-exempt non-interstate pipelines post daily the capacities of, volumes scheduled at, and actual volumes flowing through, their major receipt and delivery points and mainline segments. Initial comments were filed by numerous parties on March 13, 2008. A Technical Conference was held on April 3, 2008. Numerous reply comments were received on April 14, 2008.

On December 26, 2007, the FERC issued Order No. 704 in this docket implementing only the annual reporting provisions of the NOPR with minimal changes to the original proposal. The order became effective February 4, 2008. The initial report is due May 1, 2009 for calendar year 2008. Subsequent reports are due by May 1 of each year for the previous calendar year. Order 704 will require most, if not all Kinder Morgan natural gas pipelines to report annual volumes of relevant transactions to the FERC. Technical workshops were held on April 22, 2008 and May 19, 2008.

FERC Equity Return Allowance

On April 17, 2008, the FERC adopted a new policy under Docket No. PL07-2-000 that will allow master limited partnerships to be included in proxy groups for the purpose of determining rates of return for both interstate natural gas and oil pipelines. Additionally, the policy statement concluded that (i) there should be no cap on the level of distributions included in the FERC's current discounted cash flow methodology; (ii) the Institutional Brokers

Estimated System forecasts should remain the basis for the short-term growth forecast used in the discounted cash flow calculation; (iii) there should be an adjustment to the long-term growth rate used to calculate the equity cost of capital for a master limited partnership, specifically the long term growth rate would be set at 50% of the gross domestic product; and (iv) there should be no modification to the current respective two-thirds and one-third weightings of the short-term and long-term growth factors. Additionally, the FERC decided not to explore other methods for determining a pipeline's equity cost of capital at this time. The policy statement will govern all future gas and oil rate proceedings involving the establishment of a return on equity, as well as those cases that are currently pending before either the FERC or an administrative law judge. On May 19, 2008, an application for rehearing was filed by The American Public Gas Association. On June 13, 2008, the FERC dismissed the request for rehearing.

Notice of Proposed RuleMaking - Rural Onshore Low Stress Hazardous Liquids Pipelines

On September 6, 2006, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to in this report as the PHMSA, published a notice of proposed rulemaking (PHMSA 71 FR 52504) that proposed to extend certain threat-focused pipeline safety regulations to rural onshore low-stress hazardous liquid pipelines within a prescribed buffer of previously defined U.S. states. Low-stress hazardous liquid pipelines, except those in populated areas or that cross commercially navigable waterways, have not been subject to the safety regulations in PHMSA 49 C.F.R. Part 195.1. According to the PHMSA, unusually sensitive areas are areas requiring extra protection because of the presence of sole-source drinking water resources, endangered species, or other ecological resources that could be adversely affected by accidents or leaks occurring on hazardous liquid pipelines.

The notice proposed to define a category of "regulated rural onshore low-stress lines" (rural lines operating at or below 20% of specified minimum yield strength, with a diameter of eight and five-eighths inches or greater, located in or within a quarter-mile of a U.S. state) and to require operators of these lines to comply with a threat-focused set of requirements in Part 195 that already apply to other hazardous liquid pipelines. The proposed safety requirements addressed the most common threats—corrosion and third party damage—to the integrity of these rural lines. The proposal is intended to provide additional integrity protection, to avoid significant adverse environmental consequences, and to improve public confidence in the safety of unregulated low-stress lines.

Since the new notice is a proposed rulemaking in which the PHMSA will consider initial and reply comments from industry participants, it is not clear what impact the final rule will have on the business of our intrastate and interstate pipeline companies.

Natural Gas Pipeline Expansion Filings

Rockies Express Pipeline-Currently Certificated Facilities

We operate and own a 51% ownership interest in West2East Pipeline LLC, a limited liability company that is the sole owner of Rockies Express Pipeline LLC. ConocoPhillips owns a 24% ownership interest in West2East Pipeline LLC and Sempra Energy holds the remaining 25% interest. When construction of the entire Rockies Express Pipeline project is completed, our ownership interest will be reduced to 50% at which time the capital accounts of West2East Pipeline LLC will be trued up to reflect our 50% economics in the project. According to the provisions of current accounting standards, due to the fact that we will receive 50% of the economics of the Rockies Express project on an ongoing basis, we are not considered the primary beneficiary of West2East Pipeline LLC and thus, we account for our investment under the equity method of accounting.

On August 9, 2005, the FERC approved the application of Rockies Express Pipeline LLC, formerly known as Entrega Gas Pipeline LLC, to construct 327 miles of pipeline facilities in two phases. For phase I (consisting of two pipeline segments), Rockies Express was granted authorization to construct and operate approximately 136 miles of pipeline extending northward from the Meeker Hub, located at the northern end of our TransColorado pipeline system in Rio Blanco County, Colorado, to the Wamsutter Hub in Sweetwater County, Wyoming (segment 1), and then construct approximately 191 miles of pipeline eastward to the Cheyenne Hub in Weld County, Colorado (segment 2). Construction of segments 1 and 2 has been completed, with interim service commencing on segment 1 on February 24, 2006, and full in-service of both segments on February 14, 2007. For phase II, Rockies Express was authorized to construct three compressor stations referred to as the Meeker, Big Hole and Wamsutter compressor stations. The Meeker and Wamsutter stations went into service in January 2008. Construction of the Big Hole compressor station has commenced with an expected in-service date of June 30, 2009.

Rockies Express Pipeline-West Project

On April 19, 2007, the FERC issued a final order approving the Rockies Express application for authorization to construct and operate certain facilities comprising its proposed “Rockies Express-West Project.” This project is the first planned segment extension of the Rockies Express’ currently certificated facilities, and is comprised of approximately 713 miles of 42-inch diameter pipeline extending from the Cheyenne Hub to an interconnection with Panhandle Eastern Pipe Line located in Audrain County, Missouri. The project also includes certain improvements to existing Rockies Express facilities located to the west of the Cheyenne Hub. Construction on Rockies Express-West commenced on May 21, 2007, and interim service for up to 1.4 billion cubic feet per day of natural gas on the segment’s first 503 miles of pipe began on January 12, 2008. The project commenced deliveries to Panhandle Eastern Pipe Line at Audrain County, Missouri on the remaining 210 miles of pipe on May 20, 2008. The Rockies Express West pipeline segment transports approximately 1.5 million cubic feet per day of natural gas across five states: Wyoming, Colorado, Nebraska, Kansas and Missouri.

Rockies Express expects to conduct further hydrostatic testing of portions of its system during September 2008 to satisfy U.S. Department of Transportation testing requirements to operate at its targeted higher operating pressure. This hydrostatic test will result in the temporary outage of pipeline delivery points and an overall reduction of firm capacity available to firm shippers. By the terms of the Rockies Express FERC Gas Tariff, firm shippers are entitled to daily reservation revenue credits for non-force majeure and planned maintenance outages; however, we believe any revenue credits resulting from the temporary pipeline outage will not have a material adverse impact on our business, cash flows, financial position or results of operations.

Rockies Express Pipeline-East Project

On April 30, 2007, Rockies Express filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the Rockies Express-East Project. The Rockies Express-East Project will be comprised of 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 and will be capable of transporting approximately 1.8 billion cubic feet per day of natural gas.

By order issued May 30, 2008, the FERC authorized the certificate to construct the Rockies Express Pipeline-East Project. Construction commenced on the Rockies Express-East pipeline on June 26, 2008. Subject to receipt of regulatory approvals, the project is expected to begin interim service to the Lebanon Hub in Warren County, Ohio by December 31, 2008, and be fully operational in the third quarter of 2009. We are overseeing construction of the project and we will operate the pipeline.

Current market conditions for consumables, labor and construction equipment along with certain provisions in the final Environmental Impact Study have resulted in increased costs for the project and have impacted certain projected completion dates. For example, our current estimate of total construction costs on the Rockies Express Pipeline is approximately $5.6 billion (consistent with our July 16, 2008 second quarter earnings press release), and we now expect that interim service on the East Project will begin by year-end to the Lebanon Hub, as opposed to our initial projection of Clarington, Ohio.

TransColorado Pipeline

On April 19, 2007, the FERC issued an order approving TransColorado Gas Transmission Company LLC’s application for authorization to construct and operate certain facilities comprising its proposed “Blanco-Meeker Expansion Project.” This project provides for the transportation of up to approximately 250 million cubic feet per day of natural gas from the Blanco Hub area in San Juan County, New Mexico through TransColorado’s existing interstate pipeline for delivery to the Rockies Express Pipeline at an existing point of interconnection located in the Meeker Hub in Rio Blanco County, Colorado. Construction commenced on May 9, 2007, and the project was completed and entered service January 1, 2008.

Kinder Morgan Interstate Gas Transmission Pipeline

On August 6, 2007, Kinder Morgan Interstate Gas Transmission Pipeline, referred to in this report as KMIGT, filed, in FERC Docket CP07-430, for regulatory approval to construct and operate a 41-mile, $30 million natural gas pipeline, referred to in this report as the Colorado Lateral, from the Cheyenne Hub to markets in and around Greeley, Colorado. When completed, the Colorado Lateral will provide firm transportation of up to 55 million cubic feet per day to a local utility under long-term contract. The FERC issued a draft environmental assessment on the project on January 11, 2008, and comments on the project were received February 11, 2008. On February 21, 2008, the FERC granted the certificate application. On July 8, 2008, in response to a rehearing request by Public Service Company of Colorado, referred to in this report as PSCo, the FERC granted rehearing and denied KMIGT recovery in initial transportation rates $6.2 million in costs associated with non-jurisdictional laterals constructed by KMIGT to serve Atmos. The recourse rate adjustment is not expected to have any material effect on the negotiated rate paid by Atmos to KMIGT or the economics of the project. On July 25, 2008, KMIGT filed an amendment to its certificate application, seeking authorization to revise its initial rates for transportation service on the Colorado Lateral to reflect updated construction costs for jurisdictional mainline facilities.

PSCo, a competitor serving markets off the Colorado Lateral, also filed a complaint before the State of Colorado Public Utilities Commission against Atmos, the anchor shipper on the project. The Colorado Public Utilities Commission conducted a hearing on April 14, 2008 on the complaint, which is pending a ruling. On June 9, 2008, PSCo also filed before the Colorado Public Utilities Commission seeking a temporary cease and desist order to halt construction of the lateral facilities being constructed by KMIGT to serve Atmos. Atmos filed a response to that motion on June 24, 2008. By order dated June 27, 2008 an administrative law judge for the Colorado Public Utilities Commission denied PSCo’s request for cease and desist. The Colorado Lateral facilities are currently planned to be in service by October 1, 2008.

On December 21, 2007, KMIGT filed, in Docket CP 08-44, for approval to expand its system in Nebraska to serve incremental ethanol and industrial load. No protests to the application were filed and the project was approved by the FERC. Construction commenced on April 9, 2008. These facilities are currently planned to be in service by October 1, 2008.

Kinder Morgan Louisiana Pipeline

On September 8, 2006, in FERC Docket No. CP06-449-000, we filed an application with the FERC requesting approval to construct and operate our Kinder Morgan Louisiana Pipeline. The natural gas pipeline will extend approximately 135 miles from Cheniere’s Sabine Pass liquefied natural gas terminal in Cameron Parish, Louisiana, to various delivery points in Louisiana and will provide interconnects with many other natural gas pipelines, including Natural Gas Pipeline Company of America LLC. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total. The entire project cost is approximately $594 million, and it is expected to be in service by April 1, 2009.

On March 15, 2007, the FERC issued a preliminary determination that the authorizations requested, subject to some minor modifications, will be in the public interest. This order does not consider or evaluate any of the environmental issues in this proceeding. On April 19, 2007, the FERC issued the final EIS, which addressed the potential environmental effects of the construction and operation of the Kinder Morgan Louisiana Pipeline. The final EIS was prepared to satisfy the requirements of the National Environmental Policy Act. It concluded that approval of the Kinder Morgan Louisiana Pipeline project would have limited adverse environmental impacts. On June 22, 2007, the FERC issued an order granting construction and operation of the project. Kinder Morgan Louisiana Pipeline officially accepted the order on July 10, 2007.

On July 11, 2008, Kinder Morgan Louisiana Pipeline filed an amendment to its certificate application, seeking authorization to revise its initial rates for transportation service on the Kinder Morgan Louisiana Pipeline system to reflect updated construction costs for the project.

Midcontinent Express Pipeline

On October 9, 2007, in Docket No. CP08-6-000, Midcontinent Express Pipeline LLC filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the approximate 500-mile Midcontinent Express Pipeline natural gas transmission system.

The Midcontinent Express Pipeline will create long-haul, firm transportation takeaway capacity either directly or indirectly connected to natural gas producing regions located in Texas, Oklahoma and Arkansas. The pipeline will originate in southeastern Oklahoma and traverse east through Texas, Louisiana, Mississippi, and terminate at an interconnection with the Transco Pipeline near Butler, Alabama. The Midcontinent Express Pipeline is a 50/50 joint venture between us and Energy Transfer Partners, L.P., and it has a total capital cost of approximately $1.45 billion (consistent with our July 16, 2008 second quarter earnings press release). Initial design capacity for the pipeline was 1.5 billion cubic feet of natural gas per day, which was fully subscribed with long-term binding commitments from creditworthy shippers. A successful binding open season was recently completed which will increase the main segment of the pipeline's capacity to 1.8 billion cubic feet per day, subject to regulatory approval.

On July 25, 2008, the FERC approved the application made by Midcontinent Express Pipeline to construct and operate the 500-mile Midcontinent Express Pipeline natural gas transmission system along with the lease of 272 million cubic feet of capacity on the Oklahoma intrastate system of Enogex Inc. Midcontinent Express Pipeline accepted the FERC Certificate on July 30, 2008. Construction of the pipeline is expected to commence in the September of 2008 and be in service by the second quarter of 2009.

Kinder Morgan Liquid Terminals

With regard of to six of our liquids terminals, we have undertaken a U.S. Department of Transportation compliance program for certain of our tanks and internal piping. We anticipate the program will call for an incremental $3 million to $5 million of annual capital spending over the next six to ten years to improve and/or add facilities. These improvements will allow the tanks and piping previously considered as in-plant piping to conduct DOT jurisdictional transfers of products.

15. Recent Accounting Pronouncements

EITF 04-5

In June 2005, the Emerging Issues Task Force reached a consensus on Issue No. 04-5, or EITF 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." EITF 04-5 provides guidance for purposes of assessing whether certain limited partners rights might preclude a general partner from controlling a limited partnership.

For general partners of all new limited partnerships formed, and for existing limited partnerships for which the partnership agreements are modified, the guidance in EITF 04-5 is effective after June 29, 2005. For general partners in all other limited partnerships, the guidance is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005 (January 1, 2006, for us). The adoption of EITF 04-5 did not have an effect on our consolidated financial statements.

Nonetheless, as a result of EITF 04-5, as of January 1, 2006, our financial statements are consolidated into the consolidated financial statements of Knight. Notwithstanding the consolidation of our financial statements into the consolidated financial statements of Knight pursuant to EITF 04-5, Knight 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 Knight's financial statements is a legal determination based on the entity that incurs the liability. The determination of responsibility for payment among entities in our consolidated group of subsidiaries was not impacted by the adoption of EITF 04-5.

FIN 48

In July 2006, the FASB issued Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109," which became effective January 1, 2007. FIN 48 addressed the determination of how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate resolution.

Our adoption of FIN No. 48 on January 1, 2007 did not result in a cumulative effect adjustment to "Partners' Capital" on our consolidated balance sheet. Our continuing practice is to recognize interest and/or penalties related to income tax matters in income tax expense, and as of January 1, 2007, we had $1.1 million of accrued interest and no accrued penalties. As of December 31, 2007 (i) we had $0.6 million of accrued interest and no accrued penalties; (ii) we believe it is reasonably possible that our liability for unrecognized tax benefits will decrease by approximately $1.2 million during the next twelve months; and (iii) we believe approximately $5.4 million of the total $6.3 million of unrecognized tax benefits on our consolidated balance sheet as of December 31, 2007 would affect our effective income tax rate in future periods in the event those unrecognized tax benefits were recognized. In addition, we have U.S. and state tax years open to examination for the periods 2003 through 2007. As of June 30, 2008, there have been no material changes to our December 31, 2007 liability for unrecognized tax benefits, interest, penalties or to our estimated change in the liability during 2008.

SFAS No. 157

For information on SFAS No. 157, see Note 10 "—SFAS No. 157."

SFAS No. 159

On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This Statement provides companies with an option to report selected financial assets and liabilities at fair value. The Statement's objective is to reduce both complexity in accounting for financial instruments and the volatility in earnings caused by measuring related assets and liabilities differently. The Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities.

SFAS No. 159 requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company's choice to use fair value on its earnings. It also requires entities to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. The Statement does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS No. 157, discussed in Note 10 "—SFAS No. 157", and SFAS No. 107 "Disclosures about Fair Value of Financial Instruments."

This Statement was adopted by us effective January 1, 2008, at which time no financial assets or liabilities, not previously required to be recorded at fair value by other authoritative literature, were designated to be recorded at fair value. As such, the adoption of this Statement did not have any impact on our financial statements.

SFAS 141(R)

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. SFAS No. 141R defines the acquirer as the entity that obtains control of one or more businesses in the business combination and establishes the acquisition date as the date that the acquirer achieves control. 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 applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 (January 1, 2009 for us). Early adoption is not permitted. We are currently reviewing the effects of this Statement.

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 in consolidated financial statements. A noncontrolling interest, sometimes referred to as a minority interest, is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent.

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; (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 (consolidated net income and comprehensive income will be determined without deducting minority interest, however, earnings-per-share information will continue to be calculated on the basis of the net income attributable to the parent's shareholders); and (iii) changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary to be accounted for consistently and similarly—as equity transactions.

This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 (January 1, 2009 for us). Early adoption is not permitted. SFAS No. 160 is to be applied prospectively as of the beginning of the fiscal year in which it is initially applied, except for its presentation and disclosure requirements, which are to be applied retrospectively for all periods presented. We are currently reviewing the effects of this Statement.

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 is intended to help investors better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows through enhanced disclosure requirements. The enhanced disclosures 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 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008 (January 1, 2009 for us). Early application is encouraged. We are currently reviewing the effects of this Statement.

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.

This Issue is effective for fiscal years beginning after December 15, 2008 (January 1, 2009 for us), and interim periods within those fiscal years. Earlier application is not permitted, and the guidance in this Issue is to be applied retrospectively for all financial statements presented. We are currently reviewing the effects of this Issue.

FASB Staff Position No. FAS 142-3

On April 25, 2008, the FASB issued FASB Staff Position 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”. This Staff Position is effective for financial statements issued for fiscal years beginning after December 15, 2008 (January 1, 2009 for us), and interim periods within those fiscal years. Early adoption is prohibited. We are currently reviewing the effects of this Staff Position.

SFAS No. 162

On May 9, 2008, the FASB issued SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles.” This Statement is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with U.S. generally accepted accounting principles, referred to in this note as GAAP, for nongovernmental entities.

Statement No. 162 establishes that the GAAP hierarchy should be directed to entities because it is the entity (not its auditor) that is responsible for selecting accounting principles for financial statements that are presented in conformity with GAAP. Statement No. 162 is effective 60 days following the U.S. Securities and Exchange Commission’s approval of the Public Company Accounting Oversight Board Auditing amendments to AU Section 411, “The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles,” and is only effective for nongovernmental entities. We do not expect the adoption of this Statement to have any effect on our consolidated financial statements.

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

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 2007 Form 10-K.

In addition, as discussed in Note 2 to our consolidated financial statements included elsewhere in this report, our financial statements reflect:

- the April 30, 2007 transfer of Trans Mountain as if such transfer had taken place on January 1, 2006, the effective date of common control pursuant to generally accepted accounting principles. The financial information contained in this Management's Discussion and Analysis of Financial Condition and Results of Operations includes the financial results of Trans Mountain for all periods subsequent to January 1, 2006; and

- the reclassifications necessary to reflect the results of our North System as discontinued operations. However, due to the fact that the sale of our North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments pursuant to the provisions of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," we have included the North System's financial results within our Products Pipelines business segment disclosures presented in this report for the three and six months ended June 30, 2007.

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 the 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 2007 Form 10-K. There have not been any significant changes in these policies and estimates during the six months ended June 30, 2008; however, during the second quarter of 2008, we changed the date of our annual goodwill impairment test date to May 31 of each year. This change constitutes a change in the method of applying an accounting principle, as discussed in paragraph 4 of SFAS No. 154, "Accounting Changes and Error Corrections." For more information on this change, see Note 6 to our consolidated financial statements included elsewhere in this report.

Results of Operations

Consolidated

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	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)	$ 137.6	$ 147.6	$ (10.0)	(7)%
Natural Gas Pipelines(c)	182.5	144.6	37.9	26%
CO_2	216.6	128.9	87.7	68%
Terminals	140.4	110.1	30.3	28%
Trans Mountain(d)	33.4	29.6	3.8	13%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	710.5	560.8	149.7	27%
Depreciation, depletion and amortization expense(e)	(165.6)	(135.8)	(29.8)	(22)%
Amortization of excess cost of equity investments	(1.5)	(1.5)	—	—
Interest and corporate administrative expenses(f)	(181.2)	(190.8)	9.6	5%
Net income	$ 362.2	$ 232.7	$ 129.5	56%

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	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(g)	$ 278.3	$ 290.8	$ (12.5)	(4)%
Natural Gas Pipelines(h)	370.7	279.3	91.4	33%
CO_2	416.4	254.3	162.1	64%
Terminals(i)	266.2	210.6	55.6	26%
Trans Mountain(j)	63.6	(328.6)	392.2	119%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	1,395.2	706.4	688.8	98%
Depreciation, depletion and amortization expense(k)	(323.7)	(268.5)	(55.2)	(21)%
Amortization of excess cost of equity investments	(2.9)	(2.9)	—	—
Interest and corporate administrative expenses(l)	(359.7)	(351.8)	(7.9)	(2)%
Net income	$ 708.9	$ 83.2	$ 625.7	752%

(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) 2008 amount includes a $0.8 million gain from the 2007 sale of our North System, and a $0.1 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions. 2007 amount includes a $2.2 million increase in expense associated with environmental liability adjustments, and a $0.8 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions.

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

(d) 2007 amount includes earnings of $9.0 million for a period prior to our acquisition date of April 30, 2007.

(e) 2007 amount includes Trans Mountain expenses of $1.6 million for a period prior to our acquisition date of April 30, 2007.

(f) Includes unallocated interest income and income tax expense, interest and debt expense, general and administrative expenses (including unallocated litigation and environmental expenses) and minority interest expense. 2008 amount includes (i) a $1.4 million increase in non-cash compensation expense, allocated to us from Knight. We do not have any obligation, nor do we expect to pay any amounts related to this expense; and (ii) a $0.5 million increase in imputed interest expense related to our January 1, 2007 Cochin Pipeline acquisition. 2007 amount includes (i) a $21.2 million increase in non-cash compensation expense, allocated to us from Knight. Knight was responsible for the payment of this expense; (ii) a combined $1.4 million increase in expense, related to Trans Mountain interest and general and administrative expenses for a period prior to our acquisition date of April 30, 2007; (iii) a $1.1 million increase in expense for certain Trans Mountain acquisition costs; (iv) a $0.6 million increase in imputed interest expense related to our January 1, 2007 Cochin Pipeline acquisition; and (v) a total $0.2 million decrease in minority interest expense, related to the minority interest effect from all of the three month 2007 items previously listed in these footnotes.

(g) 2008 amount includes a $1.3 million gain from the 2007 sale of our North System, and a $0.7 million decrease in income resulting from unrealized foreign currency losses on long-term debt transactions. 2007 amount includes a $2.2 million increase in expense associated with environmental liability adjustments, and a $0.8 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions.

(h) 2008 amount includes a $13.1 million increase in expense resulting from unrealized mark to market losses due to the discontinuance of hedge accounting at Casper Douglas, and a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC. 2007 amount includes an expense of $1.0 million reflecting our portion of a loss from the early extinguishment of debt by Red Cedar Gathering Company.

(i) 2007 amount includes an increase in income of $1.8 million from property casualty gains associated with the 2005 hurricane season.

(j) 2007 amount includes losses of $349.2 million for periods prior to our acquisition date of April 30, 2007. This amount includes a $377.1 million impairment expense, associated with a non-cash reduction in the carrying value of Trans Mountain's goodwill.

(k) 2007 amount includes Trans Mountain expenses of $6.3 million for periods prior to our acquisition date of April 30, 2007.

(l) 2008 amount includes (i) a $2.8 million increase in non-cash compensation expense, allocated to us from Knight. We do not have any obligation, nor do we expect to pay any amounts related to this expense; and (ii) a $1.0 million increase in imputed interest expense related to our January 1, 2007 Cochin Pipeline acquisition. 2007 amount includes (i) a $23.4 million increase in non-cash compensation expense, allocated to us from Knight. We do not have any obligation, nor did we pay any amounts related to this expense; (ii) a combined $6.7 million increase in expense related to Trans Mountain interest and general and administrative expenses for periods prior to our acquisition date of April 30, 2007; (iii) a $1.7 million increase in insurance expense associated with the 2005 hurricane season; (iv) a $1.2 million increase in imputed interest expense related to our January 1, 2007 Cochin Pipeline acquisition; (v) a $1.1 million expense for certain Trans Mountain acquisition costs; and (vi) a total $3.5 million decrease in minority interest expense related to the minority interest effect from all of the six month 2007 items previously listed in these footnotes.

Benefitting from higher revenues from crude oil, carbon dioxide, and natural gas plant products sales, improved margins from our Texas intrastate pipeline, the start-up of REX West, and incremental earnings from expanded bulk and liquids terminal operations, our consolidated net income for the quarterly period ended June 30, 2008 was $362.2 million ($0.65 per diluted limited partner unit), compared to $232.7 million ($0.36 per diluted limited partner unit) for the quarterly period ending June 30, 2007. The increase in quarterly net income in 2008 was tempered by such factors as lower gasoline demand, due to higher prices and a sluggish economy, and increases in fuel costs.

For the six months ended June 30, 2008 and 2007, we earned net income of $708.9 million and $83.2 million, respectively; however, our 2007 year-to-date net income included an impairment expense of $377.1 million associated with a non-cash reduction in the carrying value of Trans Mountain's goodwill. The goodwill impairment charge was recognized by Knight in March 2007, and following our purchase of Trans Mountain from Knight on April 30, 2007, the financial results of Trans Mountain since January 1, 2006, including the impact of the goodwill impairment, are reflected in our results. For more information on this acquisition and the goodwill impairment, see Notes 2 and 6 to our consolidated financial statements included elsewhere in this report.

Because our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash consists primarily 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.

For the second quarter of 2008, total segment earnings before depreciation, depletion and amortization increased $149.7 million (27%), when compared to the second quarter of 2007. Combined, the certain items described in the footnotes to the tables above decreased total segment earnings before depreciation, depletion and amortization by $6.8 million, when compared to the second quarter last year. The remaining $156.5 million (28%) quarter-to-quarter increase was driven by better performance from our CO_2, Natural Gas Pipelines, Terminals and Trans Mountain business segments.

For the comparable six month periods, our total segment earnings before depreciation, depletion and amortization increased $688.8 million (98%) in 2008. The certain items described in the footnotes to the table above (including the goodwill impairment expense) accounted for $350.3 million of the increase. The remaining $338.5 million (32%) increase in period-to-period segment earnings before depreciation, depletion and amortization resulted from incremental earnings from our CO_2, Natural Gas Pipelines, Terminals and Trans Mountain business segments.

Products Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions, except operating statistics)			
Revenues	$ 198.6	$ 215.1	$ 396.9	$ 425.4
Operating expenses(a)	(68.5)	(77.8)	(130.9)	(150.2)
Other income(b)	0.6	2.8	1.0	2.3
Earnings from equity investments	8.7	9.0	16.2	16.4
Interest income and Other, net-income (expense)(c)	1.3	4.1	1.8	5.3
Income tax benefit (expense)	(3.1)	(5.6)	(6.7)	(8.4)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 137.6	$ 147.6	$ 278.3	$ 290.8
Gasoline (MMBbl)	100.5	113.6	198.4	220.8
Diesel fuel (MMBbl)	41.6	42.0	80.2	80.1
Jet fuel (MMBbl)	29.9	31.9	59.6	62.1
Total refined product volumes (MMBbl)	172.0	187.5	338.2	363.0
Natural gas liquids (MMBbl)	6.1	5.9	13.0	15.5
Total delivery volumes (MMBbl)(d)	178.1	193.4	351.2	378.5

(a) 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 offsetting legal liability adjustments. 2007 amounts include an increase in expense of $2.2 million associated with environmental liability adjustments.

(b) Three and six month 2008 amounts include gains of $0.8 and $1.3 million, respectively, from the 2007 sale of our North System.

(c) 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 losses on long-term debt transactions. 2007 amounts include an increase in income of $0.8 million resulting from unrealized foreign currency gains 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 increased our Products Pipelines' segment earnings before depreciation, depletion and amortization expenses by $2.3 million and $2.0 million, respectively, when compared to the second quarter and first six months of last year. Following is information related to the increases and decreases, in the second quarter and first six months of 2008 compared to the same periods of 2007, of the segment's remaining changes in earnings before depreciation, depletion and amortization expense (EBDA); and changes in operating revenues:

Three months ended June 30, 2008 versus Three months ended June 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
North System	$ (7.7)	(100)%	$ (13.5)	(100)%
Pacific operations	(4.6)	(7)%	(0.4)	—
West Coast Terminals	(2.4)	(17)%	(0.2)	(1)%
Cochin Pipeline System	(1.3)	(18)%	(5.7)	(34)%
Central Florida Pipeline	2.1	23%	2.0	18%
Southeast Terminals	1.0	9%	0.4	2%
All other (including eliminations)	0.6	2%	0.9	2%
Total Products Pipelines	$ (12.3)	(8)%	$ (16.5)	(8)%

Six months ended June 30, 2008 versus Six months ended June 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
North System	$ (17.1)	(100)%	$ (26.7)	(100)%
Pacific operations	(1.4)	(1)%	2.6	1%
West Coast Terminals	(2.3)	(9)%	1.0	3%
Cochin Pipeline System	(1.8)	(10)%	(12.5)	(33)%
Central Florida Pipeline	2.9	16%	2.4	11%
Southeast Terminals	3.4	17%	2.0	5%
All other (including eliminations)	1.8	3%	2.7	3%
Total Products Pipelines	$ (14.5)	(5)%	$ (28.5)	(7)%

The period-to-period decreases in both segment earnings before depreciation, depletion and amortization expenses and segment revenues attributable to our North System were due to our October 2007 divestiture of the approximate 1,600-mile interstate common carrier liquids pipeline system and our 50% ownership interest in the Heartland Pipeline Company (collectively referred to in this report as our North System) to ONEOK Partners, L.P. Following purchase price adjustments, we received approximately $295.7 million in cash for the sale of our North System. We accounted for our North System business as a discontinued operation pursuant to generally accepted accounting principals which require that our income statement be formatted to separate the divested business from our continuing operations; however, as discussed above, due to the fact that the sale of our North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments, we have included the North System's operating results within our Products Pipelines business segment disclosures presented in this report for all periods presented in this discussion and analysis. This decision was based on the way our management organizes segments internally to make operating decisions and assess performance.

We earned net income from our North System (discontinued operations) of $5.4 million and $12.5 million, respectively, for the three and six months ended June 30, 2007, and we recognized a $152.8 million gain on disposal of the North System in the fourth quarter of 2007. We also recorded incremental gain adjustments of $0.8 million and $1.3 million, respectively, in the second quarter and first six months of 2008. For more information regarding this transaction, see Note 2 to our consolidated financial statements included elsewhere in this report. For information on our reconciliation of segment information with our consolidated general-purpose financial statements, see Note 11 to our consolidated financial statements included elsewhere in this report.

Both period-to-period decreases in earnings before depreciation, depletion and amortization from our Pacific operations were driven by a $6.6 million (48%) increase in operating and maintenance expenses in the second quarter of 2008, relative to the second quarter last year. The increase was primarily due to increased major maintenance and pipeline integrity expenses (resulting mainly from project timing), lower capitalized overhead credits, and incremental expenses resulting from environmental liability adjustments.

The higher operating expenses were partially offset by lower fuel and power expenses, due largely to decreases of 8% and 5%, respectively, in total mainline delivery volumes (primarily gasoline volumes). For the comparable quarters, our Pacific operations' revenues were essentially flat, as the drop in mainline delivery volumes were offset by higher average tariff rates; for the comparable six month periods, total operating revenues increased a slight 1% ($2.6 million), driven by higher average tariff rates in 2008 on refined petroleum products deliveries to Arizona and to various West Coast military bases, due to a more favorable mix of higher-rate East Line volumes versus lower-rate West Line volumes.

The decreases in earnings before depreciation, depletion and amortization expenses and in revenues from our Cochin Pipeline were largely attributable to lower deliveries of propane volumes in 2008; however, we believe the issue was partly mitigated through the implementation of a shipper provided line-fill program that began April 1, 2008. Going forward, we expect the line-fill program, along with increased shipper sales, exchange and marketing activities, to help increase propane volumes.

The decreases in earnings from our West Coast terminal operations were mainly due to incremental gains from asset sales in the second quarter of 2007. In June 2007, we recognized a $3.6 million gain on the sale of our interest in the Black Oil pipeline system in Los Angeles, California. Although total revenues from our West Coast terminals dropped a slight $0.2 million (1%) in the second quarter of 2008, when compared to the second quarter a year ago, revenues increased $1.0 million (3%) in the first half of 2008, driven by higher petroleum throughput revenues from our combined Carson, California/Los Angeles Harbor terminal system, largely due to the completion of storage expansion projects since the middle of 2007.

All of the of the remaining assets in our Products Pipelines business segment produced higher earnings before depreciation, depletion and amortization expenses in the second quarter and first six months of 2008, when compared to the same periods last year, and the primary increases were related to our Central Florida Pipeline and our Southeast liquids terminal operations. These two operations benefitted from increased demand for ethanol and from our completion of a number of capital expansion projects that modified and upgraded infrastructure, enabling us to provide additional ethanol related services to our customers.

In addition, the increases in earnings from our Central Florida Pipeline were also related to higher product delivery revenues, driven by an increase in the average tariff per barrel moved as a result of a mid-year 2007 tariff rate increase on product deliveries. The period-to-period earnings increases from our Southeast terminal operations were also driven by improved margins on liquids inventory sales.

Although combined segment revenues from refined petroleum products deliveries increased approximately 2% in the second quarter of 2008, when compared to the second quarter last year, the segment's volumes were clearly impacted by reductions in demand driven by higher crude oil and product prices and by weaker economic conditions. Total refined products delivery volumes decreased 8.3% when compared to the second quarter of 2007, reflecting an 11.5% drop in gasoline volumes, a 6.3% drop in jet fuel volumes, and a slight 1% decline in diesel fuel volumes. The segment's deliveries of natural gas liquids increased 3.4% in the second quarter of 2008, primarily due to a strong performance from our Cypress Pipeline. For the first six months of 2008, total refined products revenues were up 2.7%, compared to the first half of 2007, but total refined product delivery volumes were down 6.8%. Excluding Plantation, total refined products delivery volumes decreased 5.0% in the first half of 2008 versus the first half of 2007.

Natural Gas Pipelines

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(In millions, except operating statistics)			
Revenues	$ 2,644.7	$ 1,693.1	$ 4,557.2	$ 3,228.5
Operating expenses(a)	(2,515.6)	(1,555.4)	(4,260.7)	(2,961.1)
Other income	2.7	2.7	2.7	2.7
Earnings from equity investments(b)	31.3	3.8	54.8	10.2
Interest income and Other, net-income (expense)(c)	17.7	0.2	17.9	0.2
Income tax benefit (expense)	1.7	0.2	(1.2)	(1.2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 182.5	$ 144.6	$ 370.7	$ 279.3
Natural gas transport volumes (Trillion Btus)(d)	545.1	429.5	1,040.5	834.5
Natural gas sales volumes (Trillion Btus)(e)	224.9	207.6	440.0	416.6

(a) Three and six month 2008 amounts include a $13.1 million increase in expense resulting from unrealized mark to market losses due to the discontinuance of hedge accounting. Beginning in the second quarter of 2008, our Casper and Douglas gas processing operations discontinued hedge accounting.

(b) Six month 2007 amount includes an expense of $1.0 million reflecting our portion of a loss from the early extinguishment of debt by Red Cedar Gathering Company.

(c) Three and six month 2008 amounts include a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC.

(d) Includes Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC, TransColorado Gas Transmission Company LLC, Rockies Express Pipeline LLC, and Texas intrastate natural gas pipeline group pipeline volumes.

(e) Represents Texas intrastate natural gas pipeline group volumes.

For the three and six months ended June 30, 2008, the certain items related to our Natural Gas Pipelines business segment described in the footnotes to the table above decreased earnings before depreciation, depletion and amortization expenses by $0.1 million and increased earnings before depreciation, depletion and amortization by $0.9 million, respectively, when compared to the same periods last year.

The largest of these items includes (i) a comparable increase in earnings of $13.0 million in the second quarter of 2008 due to the sale of our 25% ownership interest in Thunder Creek Gas Services, LLC; and (ii) a decrease in earnings in the second quarter of 2008 of $13.1 million due to an unrealized mark to market loss resulting from the removal of hedge designation on certain derivative contracts used to mitigate the price risk associated with future sales of natural gas liquids by our Casper and Douglas natural gas processing operations. Effective April 1, 2008, we sold our equity ownership interest in Thunder Creek to a third party and we received cash proceeds, net of closing costs and settlements, of approximately $50.7 million for our investment. We recognized a gain of $13.0 million with respect to this transaction. For more information on this gain, see Note 2 to our consolidated financial statements included elsewhere in this report; for more information on our expense from the discontinuance of hedge accounting, see Note 10 to our consolidated financial statements included elsewhere in this report.

Following is information related to the increases and decreases, in the second quarter and first six months of 2008 compared to the same periods of 2007, of the segment's remaining changes in earnings before depreciation, depletion and amortization expense (EBDA); and changes in operating revenues:

Three months ended June 30, 2008 versus Three months ended June 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Rockies Express Pipeline	$ 28.5	724%	$ —	—
Texas Intrastate Natural Gas Pipeline Group	4.5	5%	928.3	58%
TransColorado Pipeline	3.0	28%	3.1	25%
Kinder Morgan Louisiana Pipeline	3.0	n/a	—	—
Casper and Douglas gas processing	(2.1)	(42)%	17.8	77%
All others	1.1	2%	2.4	4%
Intrasegment Eliminations	—	—	—	—
Total Natural Gas Pipelines	$ 38.0	26%	$ 951.6	56%

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Six months ended June 30, 2008 versus Six months ended June 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Rockies Express Pipeline	$ 45.3	808%	$ —	—
Texas Intrastate Natural Gas Pipeline Group	36.5	22%	1,284.2	25%
TransColorado Pipeline	6.1	29%	6.8	27%
Kinder Morgan Louisiana Pipeline	3.0	n/a	—	—
Casper and Douglas gas processing	(2.8)	(32)%	36.9	87%
All others	2.4	3%	3.2	3%
Intrasegment Eliminations	—	—	(2.4)	(385)%
Total Natural Gas Pipelines	$ 90.5	32%	$ 1,328.7	41%

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The overall increases in segment earnings before depreciation, depletion and amortization expenses in the three and six months ended June 30, 2008, when compared to the same periods last year, were driven primarily by incremental contributions from our 51% equity ownership interest in the Rockies Express Pipeline, higher earnings from our Texas intrastate natural gas pipeline group, and improved performance from our TransColorado Pipeline and Louisiana Pipeline.

The incremental earnings from our investment in Rockies Express relates to higher net income earned by Rockies Express Pipeline LLC, primarily due to the start-up of service on the Rockies Express-West pipeline segment in January and May 2008. The Rockies Express-West segment is a 713-mile, 42-inch diameter pipeline that extends from the Cheyenne Hub in Weld County, Colorado to an interconnect with Panhandle Eastern Pipeline Company in Audrain County, Missouri. Rockies Express-West began interim service for up to 1.4 billion cubic feet per day of natural gas on the segment's first 503 miles of pipe on January 12, 2008, and service on the remaining 210 miles (to Audrain County) began on May 20, 2008.

Now fully operational, Rockies Express-West has the capacity to transport up to 1.5 billion cubic feet per day and can make deliveries to interconnects with our Kinder Morgan Interstate Gas Transmission Pipeline, Northern Natural Gas Company, Natural Gas Pipeline Company of America LLC, ANR and Panhandle Eastern Pipeline Company. Rockies Express expects to conduct further hydrostatic testing of portions of its system during September 2008 to satisfy U.S. Department of Transportation testing requirements to operate at its targeted higher operating pressure. This hydrostatic test will result in the temporary outage of pipeline delivery points and an overall reduction of firm capacity available to firm shippers. By the terms of the Rockies Express FERC Gas Tariff, firm shippers are entitled to daily reservation revenue credits for non-force majeure and planned maintenance outages; however, we believe any revenue credits resulting from the temporary pipeline outage will not have a material adverse impact on our business, cash flows, financial position or results of operations.

Our Texas intrastate natural gas pipeline group includes the operations of our (i) Kinder Morgan Tejas (including Kinder Morgan Border Pipeline); (ii) Kinder Morgan Texas Pipeline; (iii) Kinder Morgan North Texas Pipeline; and (iv) Mier-Monterrey Mexico Pipeline, and combined, the group's quarter-to-quarter increase in earnings in 2008 versus 2007 was mainly attributable to higher natural gas sales margins and greater natural gas processing volumes and margins. For the comparable six month periods, the group also benefitted, in 2008, from incremental natural gas transport and storage revenues due to a long-term contract with one of its largest customers that became effective April 1, 2007.

The quarter-to-quarter increase in natural gas sales margin was driven by increases in the average unit margin and natural gas sales volumes of 9% and 8%, respectively; for the comparable six month periods, the higher margin in 2008 was primarily related to an over 5% increase in sales volumes. Since the second quarter of 2007, our Texas intrastate pipeline group has also benefitted from increases in gas processing margins.

Because our Texas intrastate group buys and sells significant quantities of natural gas, the variances from period to period in both segment revenues and segment operating expenses (which include natural gas costs of sales) are due to changes in our intrastate groups' average prices and volumes for natural gas purchased and sold. To the extent possible, we balance the pricing and timing of our natural gas purchases to our natural gas sales, and these contracts are frequently settled in terms of an index price for both purchases and sales. In order to minimize commodity price risk, we attempt to balance sales with purchases at the index price on the date of settlement.

The increases in earnings from our TransColorado Pipeline reflect contract improvements and expansions completed since the end of the second quarter of 2007, caused by an increase in natural gas production in the Piceance and San Juan basins of New Mexico and Colorado. In December 2007, we completed an approximate $50 million expansion project on our TransColorado Pipeline. The Blanco-Meeker project was placed into service January 1, 2008, and boosted natural gas transportation capacity on the pipeline by approximately 250 million cubic feet per day from the Blanco Hub area in San Juan County, New Mexico through TransColorado's existing pipeline for deliveries to the Rockies Express Pipeline at an existing point of interconnection located at the Meeker Hub in Rio Blanco County, Colorado. All of the incremental capacity is subscribed under a long-term contract with ConocoPhillips.

The $3.0 million incremental earnings contribution from our Kinder Morgan Louisiana Pipeline reflects other non-operating income realized in the second quarter of 2008 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.

The decreases in period-to-period earnings before depreciation, depletion and amortization from our Casper Douglas gas processing operations was largely due to lower prices on our product sales due to unfavorable hedge settlements and to increased natural gas purchase costs. The lower prices primarily resulted from the settlements of higher priced crude oil hedges that we used to hedge our heavy natural gas products sales, and the increased gas purchase costs were due to increases in both prices and volumes, relative to last year.

CO_2

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(In millions, except operating statistics)			
Revenues	$ 308.6	$ 199.5	$ 595.0	$ 391.1
Operating expenses	(96.6)	(76.2)	(187.3)	(146.8)
Other expense	—	—	—	—
Earnings from equity investments	5.5	5.0	11.1	10.2
Other, net-income (expense)	—	—	(0.2)	—
Income tax benefit (expense)	(0.9)	0.6	(2.2)	(0.2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 216.6	$ 128.9	$ 416.4	$ 254.3
Carbon dioxide delivery volumes (Bcf)(a)	178.6	156.6	358.8	322.2
SACROC oil production (gross)(MBbl/d)(b)	27.5	28.0	27.4	28.9
SACROC oil production (net)(MBbl/d)(c)	22.9	23.3	22.8	24.1
Yates oil production (gross)(MBbl/d)(b)	28.1	27.0	28.3	26.6
Yates oil production (net)(MBbl/d)(c)	12.5	12.0	12.6	11.8
Natural gas liquids sales volumes (net)(MBbl/d)(c)	9.1	9.7	9.3	9.7
Realized weighted average oil price per Bbl(d)(e)	$ 53.01	$ 34.76	$ 51.52	$ 34.97
Realized weighted average natural gas liquids price per Bbl(e)(f)	$ 77.28	$ 50.35	$ 71.48	$ 46.05

(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 approximate 97% working interest in the SACROC unit and an approximate 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 consists of Kinder Morgan CO_2 Company, L.P. and its consolidated affiliates. The 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 2008 and 2007, of the segment's (i) earnings before depreciation, depletion and amortization (EBDA); and (ii) operating revenues:

Three months ended June 30, 2008 versus Three months ended June 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ 28.1	64%	$ 34.2	77%
Oil and Gas Producing Activities	59.6	70%	84.5	51%
Intrasegment Eliminations	—	—	(9.6)	(91)%
Total CO_2	$ 87.7	68%	$ 109.1	55%

Six months ended June 30, 2008 versus Six months ended June 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ 57.1	69%	$ 65.4	75%
Oil and Gas Producing Activities	105.0	61%	154.2	47%
Intrasegment Eliminations	—	—	(15.7)	(71)%
Total CO_2	$ 162.1	64%	$ 203.9	52%

The overall period-to-period increases in segment earnings before depreciation, depletion and amortization expenses resulted from higher earnings from both oil and gas producing activities and carbon dioxide sales and transportation activities. Highlights for the second quarter of 2008 compared to the second quarter of 2007 included an increase in oil production at the Yates field unit, and higher earnings from increased carbon dioxide, crude oil, and natural gas liquids sales revenues, due largely to continuing increases in average crude oil (which also impacts the price of carbon dioxide) and natural gas plant product prices since the second quarter of 2007.

Revenues from crude oil sales and natural gas plant products sales increased $59.8 million (53%) and $19.1 million (43%), respectively, in the second quarter of 2008 compared to the second quarter of 2007, and increased $106.7 million (46%) and $39.4 million (49%), respectively, in the first six months of 2008 compared to the first six months of 2007. With respect to crude oil, overall sales volumes were essentially flat across both three and six month comparable periods, but we benefitted from increases of 53% and 47%, respectively, in our realized weighted average price per barrel; with respect to natural gas liquids, decreases in sales volumes of 6% and 4%, respectively, were more than offset by increases of 53% and 55%, respectively, in our realized weighted average price per barrel. The period-to-period decreases in natural gas liquids volumes were primarily attributable to operational issues on a third party owned pipeline, which resulted in pro-rationing.

Average gross oil production for the second quarter of 2008 was 28.1 thousand barrels per day at the Yates unit, over 4% higher compared to the second quarter of 2007. At SACROC, average gross oil production for the second quarter of 2008 was 27.5 thousand barrels per day, a decline of almost 2% versus the same quarter last year, but up slightly (almost 1%) compared to the previous quarter (first quarter of 2008).

Generally, earnings for 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, are closely aligned with industry price levels for crude oil and natural gas liquids products. Because such price levels 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. We mitigate this risk through a long-term hedging strategy that is intended to generate more stable realized prices by using derivative contracts as hedges to the exposure of fluctuating expected future cash flows produced by changes in commodity sales prices. All of our hedge gains and losses for crude oil and natural gas liquids are included in our realized average price for oil. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $123.03 per barrel in the second quarter of 2008, and $61.39 per barrel in the second quarter of 2007. For more information on our hedging activities, see Note 10 to our consolidated financial statements included elsewhere in this report.

The period-to-period increases in earnings before depreciation, depletion and amortization from the segment's sales and transportation activities were largely revenue related, reflecting both higher carbon dioxide sales revenues and higher carbon dioxide and crude oil pipeline transportation revenues. Overall, our CO_2 segment reported increases of $18.1 million (118%) and $34.0 million (121%), respectively, in carbon dioxide sales revenues in the second quarter and first half of 2008, relative to the same periods a year ago. The increases in sales revenues were primarily driven by increases of 84% and 81%, respectively, in average sales prices in 2008, and partially driven by increases in sales volumes of 12% and 11%, respectively. The increases in average sales prices reflect continued customer demand for carbon dioxide for use in oil recovery projects throughout the Permian Basin area and, in addition, a portion of our carbon dioxide contracts are tied to crude oil prices, which as discussed above, have increased since the second quarter of 2007. We do not recognize profits on carbon dioxide sales to ourselves.

The increases in sales volumes were largely due to the January 1, 2008 start-up of our new Doe Canyon carbon dioxide source field located in Dolores County, Colorado. Since January 2007, we have invested approximately $87 million to develop this new carbon dioxide source field (named the Doe Canyon Deep unit). In addition, investments were also made to drill additional carbon dioxide wells at the McElmo Dome unit, increase transportation capacity on the Cortez Pipeline, and extend the Cortez Pipeline to the new Doe Canyon Deep unit.

Compared to the second quarter and first half of 2007, the segment's $20.4 million (27%) and $40.5 million (28%) increases in combined operating expenses in the three and six months ended June 30, 2008, respectively, were largely due to higher severance and property tax expenses, field operating expenses, and fuel and power expenses. The increases in severance tax expenses were related to the period-to-period increases in crude oil revenues; the increases in property tax expenses were largely due to increased asset infrastructure resulting from the capital investments we have made since the end of the second quarter of 2007. The increases in operating expenses were driven by higher well workover and repair expenses related to infrastructure expansions at the SACROC and Yates oil field units and at the McElmo Dome carbon dioxide unit. In addition to its effect on product sales revenues, rising price levels since the end of the second quarter of 2007 also contributed to the increases in the segment's operating, maintenance, and fuel and power expenses.

Terminals

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(In millions, except operating statistics)			
Revenues	$ 300.7	$ 229.0	$ 580.9	$ 444.1
Operating expenses	(156.0)	(117.1)	(308.8)	(232.9)
Other income (expense)(a)	(0.2)	1.7	0.4	4.4
Earnings from equity investments	0.7	—	1.7	—
Other, net-income (expense)	1.4	—	2.7	—
Income tax expense	(6.2)	(3.5)	(10.7)	(5.0)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 140.4	$ 110.1	$ 266.2	$ 210.6
Bulk transload tonnage (MMtons)(b)	26.7	25.1	49.8	48.3
Liquids leaseable capacity (MMBbl)	52.4	43.7	52.4	43.7
Liquids utilization %	98.1%	97.1%	98.1%	97.1%

(a) Six month 2007 amount includes an increase in income of $1.8 million from property casualty gains associated with the 2005 hurricane season.

(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. As described in footnote (a) to the table above, the segment recognized a $1.8 million gain in the first quarter of 2007, based upon our final determination of the book value of fixed assets damaged or destroyed during Hurricanes Katrina and Rita in 2005.

The segment's $30.3 million (28%) increase in earnings before depreciation, depletion and amortization in the second quarter of 2008 versus the second quarter of 2007, and its remaining $57.4 million (27%) increase in earnings in the first half of 2008 versus the first half of 2007 were due to a combination of internal expansions and strategic acquisitions completed since the second quarter of 2007. Since May 30, 2007, we have invested approximately $163.1 million in cash to acquire both terminal assets and equity interests in terminal operations and combined, these acquired operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $12.6 million, revenues of $32.6 million, equity earnings of $0.7 million, and operating expenses of $20.7 million, respectively, in the second quarter of 2008, and incremental earnings before depreciation, depletion and amortization of $24.9 million, revenues of $65.5 million, equity earnings of $1.7 million, and operating expenses of $42.3 million, respectively, in the first six months of 2008.

All of the incremental amounts listed above represent the earnings, revenues and expenses from acquired terminals' operations during the additional months of ownership in 2008, and do not include increases or decreases during the same months we owned the assets in 2007. Our significant terminal acquisitions since the beginning of the second quarter of 2007 included the following:

- the Vancouver Wharves bulk marine terminal, which includes five deep-sea vessel berths and terminal assets located on the north shore of the Port of Vancouver's main harbor. The assets include significant rail infrastructure, dry bulk and liquid storage, and material handling systems, and were acquired May 30, 2007; and

- the terminal assets and operations acquired from Marine Terminals, Inc., which are primarily involved in the handling and storage of steel and alloys and consist of two separate facilities located in Blytheville, Arkansas, and individual terminal facilities located in Decatur, Alabama; Hertford, North Carolina; and Berkley, South Carolina. The assets were acquired September 1, 2007.

For all other terminal operations (those owned during identical periods in both 2008 and 2007), earnings before depreciation, depletion and amortization expenses increased $17.7 million (16%) in the second quarter of 2008, and $32.5 million (16%) in the first six months of 2008, when compared to the same prior year periods.

The overall increases in earnings from terminals owned during identical periods in both years included (i) incremental earnings before depreciation, depletion and amortization of $7.2 million (28%) from our two large Gulf Coast liquids terminal facilities located along the Houston Ship Channel in Pasadena and Galena Park, Texas, primarily due to record liquids throughput volumes as a result of expansions completed since the second quarter of 2007; (ii) incremental earnings of $4.6 million (179%) from our Pier IX terminal located in Newport News, Virginia, due to higher quarter-over-quarter coal transfer volumes (including record coal throughput volumes in June 2008 of 1.1 million tons); and incremental earnings of $1.2 million (47%) from our Perth Amboy, New Jersey liquids terminal, located in the New York Harbor area, driven by higher liquids throughput volumes as a result of an expansion completed at the end of the first quarter of 2008.

For the Terminals segment combined, expansion projects completed since the end of the second quarter of 2007 have increased our liquids terminals' leaseable capacity to 52.4 million barrels, up 20% from a capacity of 43.7 million barrels in the second quarter of 2007. At the same time, we increased our overall liquids utilization capacity rate (the ratio of our actual leased capacity to our estimated potential capacity) to 98.1%, up 1% since the second quarter last year. For all terminals combined, total liquids throughput totaled 160.6 million barrels, up 15% over second quarter 2007 volumes, due primarily to the addition of the new liquids capacity and partly to continued strong demand for imported fuel. With regard to our bulk terminals, we benefitted by incremental earnings from many of our coal handling terminals, as coal transfer volumes totaled 8.8 million tons in the second quarter of 2008, representing an increase of 22% over coal handling volumes in the second quarter of 2007.

Trans Mountain

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions, except operating statistics)			
Revenues	$ 43.4	$ 43.3	$ 86.5	$ 76.1
Operating expenses	(17.0)	(16.0)	(32.7)	(27.9)
Other income (expense)(a)	—	—	—	(377.1)
Earnings from equity investments	—	—	0.1	—
Other, net-income (expense)	4.0	0.6	6.1	1.1
Income tax benefit (expense)	3.0	1.7	3.6	(0.8)
Earnings (loss) before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(b)	$ 33.4	$ 29.6	$ 63.6	$ (328.6)
Transport volumes (MMBbl)	21.5	25.0	40.9	44.8

(a) Six month 2007 amount represents a goodwill impairment expense recorded by Knight in the first quarter of 2007.
(b) Three and six month 2007 amounts include earnings of $9.0 million and losses of $349.2 million, respectively, for periods prior to our acquisition date of April 30, 2007.

Our Trans Mountain segment includes the operations of the Trans Mountain Pipeline, which we acquired from Knight effective April 30, 2007. Trans Mountain transports crude oil and refined products from Edmonton, Alberta to marketing terminals and refineries in British Columbia and the state of Washington. An additional 15,000 barrel per day expansion that will increase capacity on the pipeline to approximately 300,000 barrels per day is currently under construction and is expected to be completed in the fourth quarter of 2008.

According to the provisions of generally accepted accounting principles that prescribe the standards used to account for business combinations, due to the fact that our acquisition of Trans Mountain from Knight represented a transfer of assets between entities under common control, we initially recorded the assets and liabilities of Trans Mountain transferred to us from Knight at their carrying amounts in the accounts of Knight. Furthermore, our accompanying financial statements included in this report, and the information in the table above, reflect the results of operations for the first six months of 2007 as though the transfer of Trans Mountain from Knight had occurred at the date when both Trans Mountain and we met the accounting requirements for entities under common control (January 1, 2006).

After taking into effect the items described in footnote (b) to the table above, the remaining increases in earnings before depreciation, depletion and amortization for the three and six months ended June 30, 2008 totaled $12.8 million (62%) and $43.0 million (209%), respectively, when compared to the same prior year periods. These period-to-period increases consisted of (i) higher earnings of $2.8 million (14%) from the two second quarter months (May and June) we owned the assets in both years; and (ii) incremental earnings of $10.0 million and $40.2 million, respectively, from periods we owned the assets in 2008 only. The increase in earnings in the second quarter of 2008 was driven primarily by higher toll rates, which more than offset a 14% decline in transport volumes due to lower demand for water-borne exports out of Vancouver, British Columbia.

Other

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(a)	$ (72.8)	$ (89.4)	$ 16.6	19%
Unallocable interest expense, net of interest income(b)	(99.9)	(98.2)	(1.7)	(2%)
Unallocable income tax benefit (expense)	(4.4)	—	(4.4)	n/a
Minority interest(c)	(4.1)	(3.2)	(0.9)	(28%)
Total interest and corporate administrative expenses	$ (181.2)	$ (190.8)	$ 9.6	5%

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(d)	$ (149.6)	$ (159.7)	$ 10.1	6%
Unallocable interest expense, net of interest income(e)	(197.6)	(190.1)	(7.5)	(4%)
Unallocable income tax benefit (expense)	(4.4)	—	(4.4)	n/a
Minority interest(f)	(8.1)	(2.0)	(6.1)	(305%)
Total interest and corporate administrative expenses	$ (359.7)	$ (351.8)	$ (7.9)	(2%)

(a) 2008 amount includes a $1.4 million increase in non-cash compensation expense, allocated to us from Knight. We do not have any obligation, nor do we expect to pay any amounts related to this expense. 2007 amount includes (i) a $21.2 million increase in non-cash compensation expense, allocated to us from Knight. We do not have any obligation, nor did we pay any amounts related to this expense; (ii) a $1.1 million increase in expense for certain Trans Mountain acquisition costs; and (iii) a $1.0 million increase in expense from the inclusion of Trans Mountain for a period prior to our acquisition date of April 30, 2007.

(b) 2008 and 2007 amounts include increases in imputed interest expense of $0.5 million and $0.6 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition. 2007 amount also includes a $0.4 million increase in interest expense from the inclusion of Trans Mountain for a period prior to our acquisition date of April 30, 2007.

(c) 2007 amount includes a $0.2 million decrease in expense related to the minority interest effect from all of the three month 2007 items previously disclosed in the footnotes to the tables included in "—Results of Operations."

(d) 2008 amount includes a $2.8 million increase in non-cash compensation expense, allocated to us from Knight. We do not have any obligation, nor do we expect to pay any amounts related to this expense. 2007 amount includes (i) a $23.4 million increase in non-cash compensation expense, allocated to us from Knight. We do not have any obligation, nor did we pay any amounts related to this expense; (ii) a $5.5 million increase in expense from the inclusion of Trans Mountain for periods prior to our acquisition date of April 30, 2007; (iii) a $1.7 million increase in expense related to an additional insurance premium charge, associated with the 2005 hurricane season; and (iv) a $1.1 million increase in expense for certain Trans Mountain acquisition costs.

(e) 2008 and 2007 amounts include increases in imputed interest expense of $1.0 million and $1.2 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition. 2007 amount also includes a $1.2 million increase in interest expense from the inclusion of Trans Mountain for periods prior to our acquisition date of April 30, 2007.

(f) 2007 amount includes a $3.5 million decrease in expense related to the minority interest effect from all of the six month 2007 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, unallocable income tax expense, interest expense, and minority interest. 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.

The total change in general and administrative expenses is an increase of $16.6 million and $10.1 for the quarter and six months ended June 30, 2008, respectively. The certain items described in footnotes (a) and (d) to the tables above accounted for decreases in general and administrative expenses of $21.9 million and $28.9 million respectively. The decreases were largely due to the $21.2 million second quarter 2007 non-cash compensation expense allocated to us from Knight and associated with the activities required to complete the May 2007 going-private transaction of KMI (now Knight). We were required to recognize the amount related to this transaction allocated to us from Knight as expense on our income statements; however, we were not responsible for paying these expenses, and accordingly, recognized the unpaid amount as a contribution to equity—primarily as an increase in "Partners' Capital" on our balance sheet.

The remaining $5.3 million (8%) and $18.8 million (15%) increases in general and administrative expenses in the comparable three and six month periods, respectively, were primarily driven by (i) acquisition-related spending, associated with the businesses we acquired since the second quarter of 2007—our Trans Mountain business segment and our recently acquired bulk terminal operations described above in "—Terminals;" and (ii) higher spending in support of growth initiatives, mainly reflecting higher compensation-related expenses—including salary and benefit expenses, payroll taxes and other employee and contractor related expenses.

Compared to the second quarter and first half of 2007, net interest expense decreased $0.5 million and $1.4 million, respectively, in 2008 due to the items described in footnotes (b) and (e) to the table above. The remaining $2.2 million (2%) quarter-to-quarter increase in expense in 2008 was chiefly attributable to a 24% increase in our average debt balances, partially offset by a 17% decrease in the weighted average interest rate on all of our borrowings. For the comparable six month periods, the remaining $8.9 million (5%) increase in interest expense in 2008 versus 2007 was driven by a 22% increase in average borrowings, partially offset by a 14% drop in weighted average interest rates.

The increase in our average borrowings since the second quarter of 2007 is largely due to the capital spending (for asset expansion and improvement projects, including additional pipeline construction costs) and the external business acquisitions we have made since June 2007. The decrease in our average borrowing rates reflects a general decrease in variable interest rates since the second quarter last year. As of June 30, 2008, approximately 45% of our $8,056.5 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. The same percentage (45%) of our total $6,629.0 million consolidated debt balance (excluding the value of interest rate swap agreements) as of June 30, 2007, was subject to variable interest rates.

The incremental unallocable income tax expense, in both the second quarter and first six months of 2008, relates to higher corporate income tax accruals for the Texas margin tax, an entity-level tax initiated January 1, 2007 and imposed on the portion of our total revenue that is apportioned to the state of Texas. The decreases in earnings from incremental minority interest expense relates to the higher overall partnership income in 2008 versus 2007.

Financial Condition

Capital Structure

We attempt to maintain a relatively conservative overall capital structure, with a long-term target mix of approximately 50% equity and 50% debt. In addition to our results of operations, our debt and capital balances are affected by our financing activities, as discussed below in "—Financing Activities."

The following table illustrates the sources of our invested capital (dollars in millions):

	June 30, 2008	December 31, 2007
Long-term debt, excluding value of interest rate swaps	$7,785.6	$6,455.9
Minority interest	42.5	54.2
Partners' capital, excluding accumulated other comprehensive loss	6,131.2	5,712.3
Total capitalization	13,959.3	12,222.4
Short-term debt, less cash and cash equivalents	192.2	551.3
Total invested capital	$ 14,151.5	$ 12,773.7
Capitalization:		
Long-term debt, excluding value of interest rate swaps	55.8%	52.8%
Minority interest	0.3%	0.5%
Partners' capital, excluding accumulated other comprehensive loss	43.9%	46.7%
	100.0%	100.0%
Invested Capital:		
Total debt, less cash and cash equivalents and excluding value of interest rate swaps	56.4%	54.9%
Partners' capital and minority interest, excluding accumulated other comprehensive loss	43.6%	45.1%
	100.0%	100.0%

Our primary cash requirements, in addition to normal operating expenses, are debt service, sustaining capital expenditures, expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholders 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 short-term commercial paper, 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. Further information on our financing strategies and activities can be found in our Annual Report on Form 10-K for the year ended December 31, 2007.

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 internal growth activities in order to maintain acceptable financial ratios.

On May 30, 2006, Standard & Poor's Rating Services and Moody's Investors Service each placed our ratings on credit watch pending the resolution of KMI's going-private transaction. On January 5, 2007, in anticipation of the buyout closing, S&P downgraded us one level to BBB and removed our rating from credit watch with negative implications. As previously noted by Moody's in its credit opinion dated November 15, 2006, it downgraded our credit rating from Baa1 to Baa2 on May 30, 2007, following the closing of the going-private transaction. Additionally, our rating was downgraded by Fitch Ratings from BBB+ to BBB on April 11, 2007. Currently, our corporate debt credit rating is BBB, Baa2 and BBB, respectively, at S&P, Moody's and Fitch.

Short-term Liquidity

Our principal sources of short-term liquidity are (i) our $1.85 billion five-year senior unsecured revolving credit facility that matures August 18, 2010; (ii) our $1.85 billion short-term commercial paper program (which is supported by our bank credit facility, with the amount available for borrowing under our credit facility being reduced by our outstanding commercial paper borrowings); and (iii) cash from operations (discussed following).

Borrowings under our five-year 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 $2.1 billion. As of June 30, 2008, there were no borrowings under our credit facility or our commercial paper program. As of December 31, 2007, there were no borrowings under our credit facility, and we had $589.1 million of commercial paper outstanding.

As of June 30, 2008, our outstanding short-term debt was $270.9 million primarily associated with long term debt which matures in 2009. We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our commercial paper program and long-term revolving credit facility. After reduction for our letters of credit and commercial paper outstanding (none at June 30, 2008), the remaining available borrowing capacity under our bank credit facility was $920.8 million as of June 30, 2008. Currently, we believe our liquidity to be adequate.

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. We 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 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.

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.

On February 12, 2008, we completed both a public offering of senior notes and an additional privately negotiated offering of 1,080,000 of our common units. We issued a total of $900 million in principal amount of senior notes, consisting of $600 million of 5.95% notes due February 15, 2018, and $300 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $894.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program. We issued the 1,080,000 common units on February 12, 2008 at a price of $55.65 per unit in a privately negotiated transaction with two investors. We received net proceeds of $60.1 million for the issuance of these common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On March 3, 2008, we issued 5,000,000 of our common units in a public offering at a price of $57.70, less commissions and underwriting expenses. At the time of the offering, we granted the underwriters a 30-day option to purchase up to an additional 750,000 common units from us on the same terms and conditions, and pursuant to this option, we issued an additional 750,000 common units on March 10, 2008 upon exercise of this option. After commissions and underwriting expenses, we received net proceeds of $324.2 million for the issuance of these 5,750,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On June 6, 2008, we completed an additional public offering of senior notes. We issued a total of $700 million in principal amount of senior notes, consisting of $375 million of 5.95% notes due February 15, 2018, and $325 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $687.7 million, and we used the proceeds to reduce the borrowings under our commercial paper program. As of June 30, 2008, our total liability balance due on the various series of our senior notes was $7,880.4 million, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $176.1 million.

We are subject to changes 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 other debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Our ability to access the public and private debt markets is affected by our credit ratings. See "—Capital Structure" above for a discussion of our credit ratings. For additional information regarding our debt securities and credit facility, see Note 9 to our consolidated financial statements included in our 2007 Form 10-K.

Operating Activities

Net cash provided by operating activities was $974.7 million for the six months ended June 30, 2008, versus $785.3 million in the comparable period of 2007. The period-to-period increase of $189.4 million (24%) in cash provided by operating activities primarily consisted of:

- a $249.3 million increase in cash from overall higher partnership income—after adding back non-cash items including, among others, depreciation and amortization expense and a $377.1 million goodwill impairment charge recognized in the first quarter of 2007. The higher partnership income reflects the increase in cash earnings from our five reportable business segments in the first half of 2008, as discussed above in "—Results of Operations;"

- a $26.0 million decrease in cash inflows relative to net changes in working capital items, mainly due to timing differences that resulted in lower net cash inflows in 2008 from the collection and payment of trade and related party receivables and payables;

- a $23.3 million decrease in cash from FERC-mandated reparation payments made in March 2008. Pursuant to FERC orders, we made reparation payments to certain shippers on our Pacific operations' pipelines and we reduced our rate case liability. The payment primarily related to a FERC ruling in February 2008 that resolved certain challenges by complainants with regard to delivery tariffs and gathering enhancement fees at our Pacific operations' Watson Station, located in Carson, California; and

- a $15.0 million decrease in cash from an interest rate swap termination payment we received in March 2007, when we terminated a fixed-to-floating interest rate swap agreement having a notional principal amount of $100 million and a maturity date of March 15, 2032.

Investing Activities

Net cash used in investing activities was $1,654.9 million for the six month period ended June 30, 2008, compared to $1,310.9 million in the comparable 2007 period. The $344.0 million (26%) increase in cash used in investing activities was primarily attributable to:

- a $572.2 million increase from higher capital expenditures—largely due to increased investment undertaken to construct our Kinder Morgan Louisiana Pipeline, and to expand our Trans Mountain crude oil and refined petroleum products pipeline system.

  Since the middle of 2007, rising construction costs continue to create a challenging business environment, and our total forecasted capital expenditures on our major projects have increased by almost 10% from the projection we made at the beginning of 2008. Most of this increase has been on our natural gas pipeline major projects—for example, market conditions for consumables, labor and construction equipment along with certain provisions in the final environmental impact statement have resulted in increased construction costs for the Rockies Express Pipeline. We continue to be extremely focused on managing these cost increases, and identifying ancillary opportunities to offset them where possible, in order to complete our expansion projects as close to on time and on budget as possible.

  Our sustaining capital expenditures, defined as capital expenditures which do not increase the capacity of an asset, were $76.8 million for the first half of 2008, compared to $63.2 million for the first half of 2007. The above amounts include our proportionate share of Rockies Express' sustaining capital expenditures but do not include the sustaining capital expenditures of our Trans Mountain business segment for periods prior to our acquisition date of April 30, 2007. Additionally, our forecasted expenditures for the remaining six months of

2008 for sustaining capital expenditures are approximately $120 million. All of our capital expenditures, with the exception of sustaining capital expenditures, are discretionary;

- a $294.9 million increase from incremental contributions to equity investments in the first half of 2008, largely driven by a $306.0 million equity investment paid in February 2008 to West2East Pipeline LLC, the sole owner of Rockies Express Pipeline LLC. Currently, we own a 51% equity interest in West2East Pipeline LLC, and 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;

- a $201.6 million increase due to higher period-to-period payments for margin and restricted deposits in 2008 compared to 2007, associated largely with our utilization of derivative contracts to hedge (offset) against the volatility of energy commodity price risks;

- a $572.4 million decrease in cash used related to our acquisition of Trans Mountain from Knight. On April 30, 2007, we paid $549.0 million to Knight to acquire the net assets of Trans Mountain, and in April 2008, we received a cash contribution of $23.4 million from Knight as a result of certain true-up provisions in our acquisition agreement. For more information on our acquisition of Trans Mountain from Knight, see Note 2 to our consolidated financial statements included elsewhere in this report;

- an $89.1 million decrease related to a return of capital received from Midcontinent Express Pipeline LLC in the first quarter of 2008. In February 2008, 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. We own a 50% equity interest in the joint venture pipeline;

- a $43.6 million decrease due to lower expenditures made for strategic business acquisitions. In the first half of 2008, our acquisition outlays totaled $4.2 million, which primarily consisted of the purchase of a Cincinnati, Ohio steel terminal. Located on approximately 17 acres along the Ohio River, the port facility primarily handles and stores break-bulk steel, and in 2007, the facility handled approximately 150,000 tons of steel products. In the first half of 2007, our acquisition outlays totaled $47.8 million, including $38.3 million paid for our purchase of the Vancouver Wharves bulk marine terminal from British Columbia Railway Company; and

- a $40.2 million decrease in cash used, relative to 2007, due to higher net proceeds received from the sales of investments, property, plant and equipment, and other net assets (net of salvage and removal costs). The increase in cash sales proceeds was driven by the approximate $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 (discussed in Note 2 to our consolidated financial statements included elsewhere in this report).

Financing Activities

Net cash provided by financing activities amounted to $701.0 million for the first six months of 2008. For the same six month period last year, our financing activities provided net cash of $579.9 million. The $121.1 million (21%) cash increase from the comparable 2007 period was primarily due to:

- a $158.6 million increase from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The period-to-period increase in cash from financing activities was primarily due to (i) a $113.6 million increase in cash inflows from higher overall net commercial paper borrowings in the first half of 2008; and (ii) a $45.1 million net increase in cash inflows from higher issuances of senior notes in the first half of 2008.

  The increase from issuances of senior notes reflects the combined $1,581.8 million we received from our February and June 2008 public offerings of senior notes (discussed in Note 7 to our consolidated financial statements included elsewhere in this report), versus the combined $1,536.7 million we received from our public offerings of senior notes in the first half of 2007. On January 30, 2007 and June 21, 2007, we completed offerings of $1.0 billion and $550 million, respectively, in principal amount of senior notes in three separate series: $600 million of 6.00% notes due February 1, 2017, $400 million of 6.50% notes due February 1, 2037, and $550 million of 6.95% notes due January 15, 2038. We used the proceeds from each of our 2008 and 2007 debt offerings to reduce the borrowings under our commercial paper program;

▪ an $86.4 million increase in cash inflows from partnership equity issuances. The increase relates to the combined $384.3 million we received from the two separate offerings of additional common units in the first half of 2008 (discussed above in "—Long-term Financing"), versus the $297.9 million we received, after commissions and underwriting expenses, in May 2007 for our issuance of an additional 5,700,000 i-units;

▪ a $32.6 million increase in cash inflows from net changes in cash book overdrafts—resulting from timing differences on checks issued but not yet endorsed; and

▪ a $158.4 million decrease from higher partnership distributions in the first six months of 2008, when compared to the first six months of 2007. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and minority interests, totaled $706.4 million in the first half of 2008, compared to $548.0 million in the same period a year ago.

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 2007 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 minority interests.

As discussed in Note 2 to our consolidated financial statements included elsewhere in this report, the transactions, balances and results of operations of our Trans Mountain pipeline system were included in our consolidated financial information as if it had been transferred to us on January 1, 2006; however, the effective date of this acquisition was April 30, 2007, and the acquisition had no impact on the distributions we made (including incentive distributions paid to our general partner) prior to this date.

On May 15, 2008, we paid a quarterly distribution of $0.96 per unit for the first quarter of 2008. This distribution was 16% greater than the $0.83 distribution per unit we paid in May 2007 for the first quarter of 2007. 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 $0.96 cash distribution per common unit. We believe that future operating results will continue to support similar levels of quarterly cash and i-unit distributions; however, no assurance can be given that future distributions will continue at such levels.

Additionally, on July 16, 2008, we declared a cash distribution of $0.99 per unit for the second quarter of 2008 (an annualized rate of $3.96 per unit). This distribution was 16% higher than the $0.85 per unit distribution we made for the second quarter of 2007. In November 2007, we announced that we expected to declare cash distributions of $4.02 per unit for 2008, an almost 16% increase over our cash distributions of $3.48 per unit for 2007. We now expect to exceed this distribution target for 2008; however, no assurance can be given that we will be able to exceed this level of distribution, and our expectation does not take into account any capital costs associated with financing the payment of reparations sought by shippers on our Pacific operations' interstate pipelines.

The incentive distribution that we paid on May 15, 2008 to our general partner (for the first quarter of 2008) was $185.8 million. Our general partner's incentive distribution that we paid in May 2007 (for the first quarter of 2007) was $138.8 million. Our general partner's incentive distribution for the distribution that we declared for the second quarter of 2008 will be $194.2 million, and our general partner's incentive distribution for the distribution that we paid for the second quarter of 2007 was $147.6 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.

Litigation and Environmental

As of June 30, 2008, we have recorded a total reserve for environmental claims, without discounting and without regard to anticipated insurance recoveries, in the amount of $88.1 million. In addition, we have recorded a receivable of $30.2 million for expected cost recoveries that have been deemed probable. As of December 31, 2007, our environmental reserve totaled $92.0 million and our estimated receivable for environmental cost recoveries totaled $37.8 million, respectively. The reserve is primarily established to address and clean up soil and ground water impacts from former releases to the environment at facilities we have acquired or accidental spills or releases at facilities that we own. Reserves for each project are generally established by reviewing existing documents, conducting interviews and performing site inspections to determine the overall size and impact to the environment. Reviews are made on a quarterly basis to determine the status of the cleanup and the costs associated with the effort. In assessing environmental risks in conjunction with proposed acquisitions, we review records relating to environmental issues, conduct site inspections, interview employees, and, if appropriate, collect soil and groundwater samples.

Additionally, as of June 30, 2008, and December 31, 2007, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $219.4 million and $247.9 million, respectively. The reserve is primarily related to various claims from lawsuits arising from our Pacific operations, 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.

Though no assurance can be given, we believe we have established adequate environmental and legal reserves such that the resolution of pending environmental matters and litigation will not have a material adverse impact on our business, cash flows, financial position or results of operations. However, changing circumstances could cause these matters to have a material adverse impact.

Pursuant to our continuing commitment to operational excellence and our focus on safe, reliable operations, we have implemented, and intend to implement in the future, enhancements to certain of our operational practices in order to strengthen our environmental and asset integrity performance. These enhancements have resulted and may result in higher operating costs and sustaining capital expenditures; however, we believe these enhancements will provide us the greater long term benefits of improved environmental and asset integrity performance.

Please refer to Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding pending litigation, environmental and asset integrity matters.

Certain Contractual Obligations

Except as set forth under "—Midcontinent Express Pipeline LLC Debt" and under "—Senior Notes" in Note 7 to our consolidated financial statements included elsewhere in this report, there have been no material changes in our contractual obligations that would affect the disclosures presented as of December 31, 2007 in our 2007 Form 10-K.

Off Balance Sheet Arrangements

Except as set forth under "—Midcontinent Express Pipeline LLC Debt" in Note 7 to our consolidated financial statements included elsewhere in this report, there have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2007 in our 2007 Form 10-K.

Fair Value Measurements

On September 15, 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." In general, fair value measurements and disclosures are made in accordance with the provisions of this Statement and, 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. For more information on our fair value measurements, see Note 10 to our consolidated financial statements included elsewhere in this report.

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;

- 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 oilsands;

- 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 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 3 to our consolidated financial statements included elsewhere in this report.

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 2007 Form 10-K, and Part II, Item 1A "Risk Factors" of this report 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 both our 2007 Form 10-K and this report. 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, 2007, in Item 7A of our 2007 Form 10-K. For more information on our risk management activities, see Note 10 to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of June 30, 2008, 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, 2008 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 3 to our consolidated financial statements entitled “Litigation, Environmental and Other Contingencies,” which is incorporated in this item by reference.

Item 1A. Risk Factors.

Except as set forth below, there have been no material changes in or additions to the risk factors disclosed in Item 1A “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2007.

Our business is subject to extensive regulation that affects our operations and costs.

Our assets and operations are subject to regulation by federal, state, provincial and local authorities, including regulation by the Federal Energy Regulatory Commission, and by various authorities under federal, state and local environmental, human health and safety and pipeline safety laws. Regulation affects almost every aspect of our business, including, among other things, our ability to determine terms and rates for our interstate pipeline services, to make acquisitions or to build extensions of existing facilities. The costs of complying with such laws and regulations are already significant, and additional or more stringent regulation could have a material adverse impact on our business, financial condition and results of operations.

In addition, regulators have taken actions designed to enhance market forces in the gas pipeline industry, which have led to increased competition. In a number of U.S. markets, natural gas interstate pipelines face competitive pressure from a number of new industry participants, such as alternative suppliers, as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material impact on business in our markets and therefore adversely affect our financial condition and results of operations.

Environmental regulation and liabilities could result in increased operating and capital costs.

Our business operations are subject to federal, state, provincial and local laws and regulations relating to environmental protection, pollution and human health and safety in the United States and Canada. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines or at or from our storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect our level of earnings and cash flows. In addition, emission controls required under federal, state and provincial environmental laws could require significant capital expenditures at our facilities. The costs of complying with such environmental laws and regulations are already significant, and additional or more stringent regulation could increase these costs or otherwise negatively affect our business.

We own and/or operate numerous properties that have been used for many years in connection with our business activities. While we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other hazardous substances may have been released at or from properties owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, handling and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and the hazardous substances released and wastes disposed thereon may be subject to laws in the United States such as the Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, which impose joint and several liability without regard to fault or the legality of the original conduct. Under the regulatory schemes of the various provinces, Canada has similar laws with respect to properties owned, operated or used by us or our predecessors. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

In addition, our oil and gas development and production activities are subject to numerous federal, state and local laws and regulations relating to environmental quality and pollution control. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, these activities are subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities in restricted areas, emissions into the environment, water discharges, and storage and disposition of wastes. In addition, legislation has been enacted that requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. The costs of complying with such laws and regulations are already significant and additional or more stringent laws and regulations could increase these costs or could otherwise negatively affect our business.

We are aware of the increasing focus of national and international regulatory bodies on greenhouse gas emissions and climate change issues. We are also aware of legislation, recently proposed by the Canadian legislature, to reduce greenhouse gas emissions. Additionally, proposed United States policy, legislation or regulatory actions may also address greenhouse gas emissions. We expect to continue to monitor and assess significant new policies, legislation or regulation in the areas where we operate, but we cannot currently estimate the potential impact of the proposals on our operations.

Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions.

As of June 30, 2008, we had outstanding $8,056.5 million of consolidated debt (excluding the value of interest rate swaps). This level of debt could have important consequences, such as:

- limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth or for other purposes;

- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make payments on our debt;

- placing us at a competitive disadvantage compared to competitors with less debt; and

- increasing our vulnerability to adverse economic and industry conditions.

Each of these factors is to a large extent dependent on economic, financial, competitive and other factors beyond our control.

Our large amount of variable rate debt makes us vulnerable to increases in interest rates.

As of June 30, 2008, approximately 44.6% of our $8,056.5 million of consolidated debt was subject to variable interest rates, either as short-term or long-term variable rate debt obligations or as long-term fixed-rate debt converted to variable rates through the use of interest rate swaps. Should interest rates increase significantly, the amount of cash required to service this debt would increase. For information on our interest rate risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk" in our Annual Report on Form 10-K for the year ended December 31, 2007.

Terrorist attacks, or the threat of them, may adversely affect our business.

The U.S. government has issued public warnings that indicate that pipelines and other energy assets might be specific targets of terrorist organizations. These potential targets might include our pipeline systems. Our operations could become subject to increased governmental scrutiny that would require increased security measures. Recent federal legislation provides an insurance framework that should cause current insurers to continue to provide sabotage and terrorism coverage under standard property insurance policies. Nonetheless, there is no assurance that adequate sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition.

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

None.

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.

*3.1 -- Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended June 30, 2001, filed on August 9, 2001).

*3.2 -- Amendment No. 1 dated November 19, 2004 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed November 22, 2004).

*3.3 -- Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed May 5, 2005).

*3.4 -- Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed April 21, 2008).

*4.1 — Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer 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 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2007 filed August 8, 2007).

*4.2 — Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer 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 5.95% Senior Notes due 2018 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Form 10-K for the year ended December 31, 2007 filed February 26, 2008).

4.3 -- 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.

*10. 1 – First Amendment to Retention and Relocation Agreement, dated as of July 16, 2008, between Knight Inc. and Scott E. Parker (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed July 25, 2008).

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

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

18 -- Letter re: change in accounting principle.

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.

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* Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

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.
(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: August 6, 2008