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

F O R M 10-Q

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

For the quarterly period ended **June 30, 2010**

or

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

For the transition period from ______to______

Commission file number: **1-11234**

KINDER MORGAN ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

The Registrant had 215,268,720 common units outstanding as of July 30, 2010.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenues				
Natural gas sales	$ 848.1	$ 716.9	$ 1,865.6	$ 1,605.6
Services	751.7	652.1	1,490.2	1,313.5
Product sales and other	361.7	276.3	735.3	512.7
Total Revenues	1,961.5	1,645.3	4,091.1	3,431.8
Operating Costs, Expenses and Other				
Gas purchases and other costs of sales	848.0	709.6	1,864.6	1,575.3
Operations and maintenance	317.5	267.3	770.4	517.3
Depreciation, depletion and amortization	223.2	203.1	450.5	413.3
General and administrative	93.4	72.6	194.5	155.1
Taxes, other than income taxes	41.1	23.4	86.2	62.4
Other expense (income)	(5.3)	(2.7)	(6.6)	(3.6)
Total Operating Costs, Expenses and Other	1,517.9	1,273.3	3,359.6	2,719.8
Operating Income	443.6	372.0	731.5	712.0
Other Income (Expense)				
Earnings from equity investments	55.2	41.9	101.9	80.1
Amortization of excess cost of equity investments	(1.5)	(1.5)	(2.9)	(2.9)
Interest, net	(116.9)	(96.0)	(228.4)	(193.2)
Other, net	(2.3)	20.2	4.4	30.9
Total Other Income (Expense)	(65.5)	(35.4)	(125.0)	(85.1)
Income Before Income Taxes	378.1	336.6	606.5	626.9
Income Taxes	(13.0)	(8.0)	(14.0)	(31.5)
Net Income	365.1	328.6	592.5	595.4
Net Income Attributable to Noncontrolling Interests	(3.9)	(4.8)	(6.0)	(7.7)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 361.2	$ 323.8	$ 586.5	$ 587.7
Calculation of Limited Partners' Interest in Net Income Attributable to Kinder Morgan Energy Partners, L.P.:				
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 361.2	$ 323.8	$ 586.5	$ 587.7
Less: General Partner's Interest	(92.5)	(232.8)	(341.7)	(456.5)
Limited Partners' Interest in Net Income	$ 268.7	$ 91.0	$ 244.8	$ 131.2
Limited Partners' Net Income per Unit	$ 0.88	$ 0.33	$ 0.81	$ 0.48
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit	304.5	277.5	301.7	273.5
Per Unit Cash Distribution Declared	$ 1.09	$ 1.05	$ 2.16	$ 2.10

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)

	June 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
Current assets		
Cash and cash equivalents	$ 143.1	$ 146.6
Restricted deposits	19.3	15.2
Accounts, notes and interest receivable, net	834.7	902.1
Inventories	101.5	71.9
Gas in underground storage	50.8	43.5
Fair value of derivative contracts	44.5	20.8
Other current assets	39.5	44.6
Total current assets	1,233.4	1,244.7
Property, plant and equipment, net	14,308.2	14,153.8
Investments	3,855.4	2,845.2
Notes receivable	188.5	190.6
Goodwill	1,205.0	1,149.2
Other intangibles, net	315.5	218.7
Fair value of derivative contracts	544.4	279.8
Deferred charges and other assets	177.9	180.2
Total Assets	$ 21,828.3	$ 20,262.2
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	$ 1,571.1	$ 594.7
Cash book overdrafts	42.8	34.8
Accounts payable	564.0	614.8
Accrued interest	232.8	222.4
Accrued taxes	56.2	57.8
Deferred revenues	78.1	76.0
Fair value of derivative contracts	189.1	272.0
Accrued other current liabilities	145.9	145.1
Total current liabilities	2,880.0	2,017.6
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	10,279.7	9,997.7
Value of interest rate swaps	737.5	332.5
Total Long-term debt	11,017.2	10,330.2
Deferred income taxes	221.3	216.8
Fair value of derivative contracts	150.3	460.1
Other long-term liabilities and deferred credits	453.3	513.4
Total long-term liabilities and deferred credits	11,842.1	11,520.5
Total Liabilities	14,722.1	13,538.1
Commitments and contingencies (Notes 4 and 10)		
Partners' Capital		
Common units	4,305.4	4,057.9
Class B units	71.6	78.6
i-units	2,752.9	2,681.7
General partner	64.6	221.1
Accumulated other comprehensive loss	(171.4)	(394.8)
Total Kinder Morgan Energy Partners, L.P. partners' capital	7,023.1	6,644.5
Noncontrolling interests	83.1	79.6
Total Partners' Capital	7,106.2	6,724.1
Total Liabilities and Partners' Capital	$ 21,828.3	$ 20,262.2

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
(In Millions)
(Unaudited)

	Six Months Ended June 30,	
	2010	**2009**
Cash Flows From Operating Activities		
Net Income	$ 592.5	$ 595.4
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	450.5	413.3
Amortization of excess cost of equity investments	2.9	2.9
Income from the allowance for equity funds used during construction	(0.6)	(20.3)
Income from the sale or casualty of property, plant and equipment and other net assets	(6.6)	(3.6)
Earnings from equity investments	(101.9)	(80.1)
Distributions from equity investments	101.9	100.3
Proceeds from termination of interest rate swap agreements	-	144.4
Changes in components of working capital:		
Accounts receivable	62.9	184.5
Inventories	(29.7)	(11.2)
Other current assets	(20.8)	(68.2)
Accounts payable	(42.7)	(278.4)
Accrued interest	10.3	21.2
Accrued taxes	(2.2)	3.4
Accrued liabilities	(13.0)	(24.3)
Rate reparations, refunds and other litigation reserve adjustments	(48.3)	(15.5)
Other, net	(23.0)	(27.0)
Net Cash Provided by Operating Activities	932.2	936.8
Cash Flows From Investing Activities		
Acquisitions of investments	(929.7)	-
Acquisitions of assets	(218.1)	(18.5)
Repayments from customers	-	109.6
Capital expenditures	(451.1)	(796.6)
Sale or casualty of property, plant and equipment, and other net assets net of removal costs	22.5	(4.7)
Investments in margin deposits	(3.9)	(24.9)
Contributions to equity investments	(180.9)	(802.8)
Distributions from equity investments in excess of cumulative earnings	93.3	-
Net Cash Used in Investing Activities	(1,667.9)	(1,537.9)
Cash Flows From Financing Activities		
Issuance of debt	4,709.5	3,237.1
Payment of debt	(3,443.0)	(2,392.8)
Repayments from related party	1.3	2.5
Debt issue costs	(22.3)	(5.6)
Increase (Decrease) in cash book overdrafts	8.1	(21.6)
Proceeds from issuance of common units	433.2	669.5
Contributions from noncontrolling interests	7.2	8.6
Distributions to partners and noncontrolling interests:		
Common units	(439.5)	(391.4)
Class B units	(11.3)	(11.2)
General Partner	(498.2)	(445.5)
Noncontrolling interests	(12.0)	(10.8)
Other, net	-	(0.2)
Net Cash Provided by Financing Activities	733.0	638.6
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(0.8)	2.5
(Decrease) Increase in Cash and Cash Equivalents	(3.5)	40.0
Cash and Cash Equivalents, beginning of period	146.6	62.5
Cash and Cash Equivalents, end of period	$ 143.1	$ 102.5
Noncash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	$ 8.1	$ 3.7
Assets acquired by the issuance of common units	$ 81.7	$ 5.0
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$ 224.7	$ 205.5
Cash paid during the period for income taxes	$ 7.9	$ 8.2

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

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

1. General

Organization

Kinder Morgan Energy Partners, L.P. is a leading pipeline transportation and energy storage company in North America, and unless the context requires otherwise, references to “we,” “us,” “our,” “KMP” or the “Partnership” are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries. We own an interest in or operate approximately 28,000 miles of pipelines and 180 terminals, and conduct our business through five reportable business segments (described further in Note 8). Our pipelines transport natural gas, refined petroleum products, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals and handle bulk materials like coal and petroleum coke. We are also the leading provider of carbon dioxide for enhanced oil recovery projects in North America. Our general partner is owned by Kinder Morgan, Inc., as discussed following.

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

Kinder Morgan, Inc., referred to as KMI in this report, is a Kansas corporation privately owned by investors led by Richard D. Kinder, Chairman and Chief Executive Officer of both Kinder Morgan G.P., Inc. (our general partner) and Kinder Morgan Management, LLC (our general partner’s delegate). KMI has been privately owned since its merger with Kinder Morgan Holdco LLC on May 30, 2007. This merger is referred to in this report as the going-private transaction and is described more fully in Note 1 to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2009, referred to in this report as our 2009 Form 10-K.

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

Kinder Morgan Management, LLC, referred to as KMR in this report, is a Delaware limited liability company. Our general partner owns all of KMR’s voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. More information on these entities and the delegation of control agreement is contained in our 2009 Form 10-K.

Basis of Presentation

We have prepared our accompanying unaudited consolidated financial statements under the rules and regulations of the United States Securities and Exchange Commission. These rules and regulations conform to the accounting principles contained in the Financial Accounting Standards Board’s Accounting Standards Codification, the single source of generally accepted accounting principles in the United States of America and referred to in this report as the Codification. Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with the Codification. We believe, however, that our disclosures are adequate to make the information presented not misleading.

In addition, 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, and certain amounts from prior periods have been reclassified to conform to the current presentation. Interim results are not necessarily indicative of results for a full year; accordingly, you should read these consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our 2009 Form 10-K.

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

In addition, our financial statements are consolidated into the consolidated financial statements of KMI; however, except for the related party transactions described in Note 9 "Related Party Transactions—Asset Acquisitions," KMI is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or KMI's financial statements is a legal determination based on the entity that incurs the liability. Furthermore, the determination of responsibility for payment among entities in our consolidated group of subsidiaries is not impacted by the consolidation of our financial statements into the consolidated financial statements of KMI.

Limited Partners' Net Income per Unit

We compute Limited Partners' Net Income per Unit by dividing our limited partners' interest in net income by the weighted average number of units outstanding during the period. The overall computation, presentation, and disclosure requirements for our Limited Partners' Net Income per Unit are made in accordance with the "Earnings per Share" Topic of the Codification.

2. Acquisitions, Joint Ventures, and Divestitures

Acquisitions

USD Terminal Acquisition

On January 15, 2010, we acquired three ethanol handling train terminals from US Development Group LLC for an aggregate consideration of $200.8 million, consisting of $115.7 million in cash, $81.7 million in common units, and $3.4 million in assumed liabilities. The three train terminals are located in Linden, New Jersey; Baltimore, Maryland; and Dallas, Texas. As part of the transaction, we announced the formation of a venture with US Development Group LLC to optimize and coordinate customer access to the three acquired terminals, other ethanol terminal assets we already own and operate, and other terminal projects currently under development by both parties. The acquisition complemented and expanded the ethanol and rail terminal operations we previously owned, and all of the acquired assets are included in our Terminals business segment.

Based on our measurement of fair market values for all of the identifiable tangible and intangible assets acquired and liabilities assumed on the acquisition date, we assigned $94.6 million of our combined purchase price to "Other intangibles, net" (representing customer relationships); $43.1 million to "Property, Plant and Equipment, net"; and a combined $5.1 million to "Other current assets" and "Deferred charges and other assets." The remaining $58.0 million of our purchase price represented the future economic benefits expected to be derived from the acquisition that was not assigned to other identifiable, separately recognizable assets acquired, and we recorded this amount as "Goodwill." We believe the primary items that generated the goodwill are the value of the synergies created between the acquired assets and our pre-existing ethanol handling assets, and our expected ability to grow the business by leveraging our pre-existing experience in ethanol handling operations. We expect that the entire amount of goodwill will be deductible for tax purposes. Furthermore, in the third quarter of 2010, we will make a final settlement with the seller for acquired working capital balances.

Slay Industries Terminal Acquisition

On March 5, 2010, we acquired certain bulk and liquids terminal assets from Slay Industries for an aggregate consideration of $101.6 million, consisting of $97.0 million in cash, assumed liabilities of $1.6 million, and an obligation to pay additional cash consideration of $3.0 million in years 2013 through 2019, contingent upon the purchased assets providing us an agreed-upon amount of earnings during the three years following the acquisition. Including accrued interest, we expect to pay approximately $2.0 million of this contingent consideration in the first half of 2013.

The acquired assets include (i) a marine terminal located in Sauget, Illinois; (ii) a transload liquid operation located in Muscatine, Iowa; (iii) a liquid bulk terminal located in St. Louis, Missouri; and (iv) a warehousing distribution center located in St. Louis. All of the acquired terminals have long-term contracts with large creditworthy shippers. As part of the transaction, we and Slay Industries entered into joint venture agreements at both the Kellogg Dock coal bulk terminal, located in Modoc, Illinois, and at the newly created North Cahokia terminal, located in Sauget and which has approximately 175 acres of land ready for development. All of the assets located in Sauget have access to the Mississippi River and are served by five rail carriers. The acquisition complemented and expanded our pre-existing Midwest terminal operations by adding a diverse mix of liquid and bulk capabilities, and all of the acquired assets are included in our Terminals business segment.

Based on our measurement of fair market values for all of the identifiable tangible and intangible assets acquired and liabilities assumed, we assigned $67.9 million of our purchase price to “Property, Plant and Equipment, net”; $24.6 million to “Other intangibles, net” (representing customer contracts); and a combined $8.2 million to “Investments.” We recorded the remaining $0.9 million of our combined purchase price as “Goodwill,” representing certain advantageous factors that contributed to our acquisition price exceeding the fair value of acquired identifiable net assets—in the aggregate, these factors represented goodwill, and we expect that the entire amount of goodwill will be deductible for tax purposes.

Mission Valley Terminal Acquisition

On March 1, 2010, we acquired the refined products terminal assets at Mission Valley, California from Equilon Enterprises LLC (d/b/a Shell Oil Products US) for $13.5 million in cash. The acquired assets include buildings, equipment, delivery facilities (including two truck loading racks), and storage tanks with a total capacity of approximately 170,000 barrels for gasoline, diesel fuel and jet fuel. The terminal operates under a long-term terminaling agreement with Tesoro Refining and Marketing Company. We assigned our entire purchase price to “Property, Plant and Equipment, net.” The acquisition enhanced our Pacific operations and complemented our existing West Coast terminal operations, and the acquired assets are included in our Products Pipelines business segment.

KinderHawk Field Services LLC Acquisition

On May 21, 2010, we completed our previously announced agreement to purchase a 50% ownership interest in Petrohawk Energy Corporation’s natural gas gathering and treating business in the Haynesville shale gas formation located in northwest Louisiana. On that date, we paid an aggregate consideration of $921.4 million in cash for our 50% equity ownership interest, and pursuant to the provisions of the joint venture formation and contribution agreement, our payment included approximately $46.4 million for both estimated capital expenditures and estimated net cash outflows from operating activities for the period January 1, 2010 through May 21, 2010.

Petrohawk will continue to operate the business during a short transition period, and following the transition period, a newly formed company named KinderHawk Field Services LLC, owned 50% by us and 50% by Petrohawk, will assume the joint venture operations. The joint venture assets consist of more than 200 miles of pipeline currently in service, and it is expected that the pipeline mileage will increase to approximately 375 miles with projected throughput of over 800 million cubic feet per day of natural gas by the end of 2010. Additionally, it is expected that the system’s natural gas amine treating plants will have capacity of approximately 2,635 gallons per minute by the end of 2010. The joint venture has also received a dedication to transport and treat all of Petrohawk’s operated Haynesville and Bossier shale gas production in northwest Louisiana for the life of the leases at agreed upon rates, as well as minimum volume commitments from Petrohawk for the first five years of the joint venture agreement. It will also focus on providing transportation services to third-party producers. The joint venture ultimately is expected to have approximately two billion cubic feet per day of throughput capacity, which will make it one of the largest gathering and treating systems in the United States.

The acquisition complemented and expanded our existing natural gas gathering and treating businesses, and we assigned our entire purchase price to “Investments” on our accompanying consolidated balance sheet as of June 30, 2010. Our investment and our pro rata share of the joint venture’s operating results are included as part of our Natural Gas Pipelines business segment.

Pro Forma Information

Pro forma consolidated income statement information that gives effect to all of the acquisitions we have made and all of the joint ventures we have entered into since January 1, 2009 as if they had occurred as of January 1, 2009 is not presented because it would not be materially different from the information presented in our accompanying consolidated statements of income.

Acquisitions Subsequent to June 30, 2010

On July 22, 2010, we acquired a terminal with ethanol tanks, a truck rack and additional acreage in Dallas, Texas, from Direct Fuels Partners, L.P. for an aggregate consideration of $16 million, consisting of $15.9 million in cash and an assumed property tax liability of $0.1 million. The acquired terminal facility is connected to the Dallas, Texas unit train terminal we acquired from USD Development Group LLC in January 2010 (described above in "Acquisitions—USD Terminal Acquisition).

Joint Ventures

Joint Venture Formations and Ownership Changes

Eagle Ford Gathering LLC

On May 14, 2010, we and Copano Energy, L.L.C. entered into formal agreements for a joint venture to provide natural gas gathering, transportation and processing services to natural gas producers in the Eagle Ford Shale formation in south Texas. The joint venture is named Eagle Ford Gathering LLC, and as previously announced in November 2009, we will own 50% of the equity in the project (a 50% member interest in Eagle Ford Gathering LLC), and Copano will own the remaining 50% interest. Copano will serve as operator and managing member of Eagle Ford Gathering LLC. We and Copano have committed approximately 375 million cubic feet per day of natural gas capacity to the joint venture through 2024 for both transportation on our natural gas pipeline that extends from Laredo to Katy, Texas, and for processing at Copano's natural gas processing plant located in Colorado County, Texas.

On July 6, 2010, Eagle Ford Gathering LLC announced the execution of a definitive long-term, fee-based gas services agreement with SM Energy Company. According to the provisions of the agreement (i) SM Energy will commit Eagle Ford production from its assets located in LaSalle, Dimmitt, and Webb Counties, Texas up to a maximum level of 200 million cubic feet per day over a ten year term; and (ii) Eagle Ford Gathering LLC will construct approximately 85-miles of 24-inch and 30-inch diameter pipeline to serve SM Energy's acreage in the western Eagle Ford Shale formation to our Freer compressor station located in Duval County, Texas. The pipeline is expected to begin service during the summer of 2011.

Combined, we and Copano will invest approximately $137 million for the first phase of construction, which will significantly extend the natural gas gathering pipeline beyond the length previously announced in November 2009. As of June 30, 2010, our capital contributions (and net equity investment) in Eagle Ford Gathering LLC totaled $0.1 million.

Midcontinent Express Pipeline LLC

On May 26, 2010, Energy Transfer Partners, L.P. transferred to Regency Energy Partners LP (i) a 49.9% ownership interest in Midcontinent Express Pipeline LLC; and (ii) a one-time right to purchase its remaining 0.1% ownership interest in Midcontinent Express Pipeline LLC on May 26, 2011. As a result of this transfer, Energy Transfer Partners, L.P. now owns a 0.1% ownership interest in Midcontinent Express Pipeline LLC. Our subsidiary, Kinder Morgan Operating L.P., "A," owns the remaining 50% ownership interest in Midcontinent Express Pipeline LLC, and we did not record any equity method adjustments as a result of the ownership change between Regency Energy Partners LP and Energy Transfer Partners, L.P.

Joint Venture Contributions

During the three and six months ended June 30, 2010, we contributed $45.3 million and $180.9 million, respectively, to our equity investees. Our combined contributions to equity investees during the first half of 2010 included contributions of $130.5 million to Rockies Express Pipeline LLC and contributions of $39.0 million to Midcontinent Express Pipeline LLC.

During the three and six months ended June 30, 2009, we contributed $629.3 million and $802.8 million, respectively, to our equity investees. Our 2009 contributions were paid primarily to West2East Pipeline LLC, Midcontinent Express Pipeline LLC, and Fayetteville Express Pipeline LLC to partially fund their respective Rockies Express, Midcontinent Express, and Fayetteville Express natural gas pipeline system construction and/or pre-construction costs. We own a 50% equity interest in Fayetteville Express Pipeline LLC. We report our equity contributions separately as "Contributions to equity investments" in our accompanying consolidated statements of cash flows for the six months ended June 30, 2010 and 2009.

Divestitures

Cypress Pipeline

On July 14, 2009, we received notice from Westlake Petrochemicals LLC, a wholly-owned subsidiary of Westlake Chemical Corporation, that it was exercising an option it held to purchase a 50% ownership interest in our Cypress Pipeline. We expect the transaction to close by the end of the third quarter of 2010. As of June 30, 2010, the net assets of our Cypress Pipeline totaled approximately $20.6 million. At the time of the sale, we will (i) deconsolidate the net assets of the Cypress Pipeline; (ii) recognize a gain or loss on the sale of net assets equal to the difference between (a) the proceeds received from the sale, and (b) 50% of the net assets' carrying value; and (iii) recognize the remaining 50% noncontrolling investment retained at its fair value (which is expected to result in a gain).

3. Intangibles

Goodwill

We evaluate goodwill for impairment on May 31 of each year. For this purpose, we have six reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (iii) Natural Gas Pipelines; (iv) CO_2; (v) Terminals; and (vi) Kinder Morgan Canada.

There were no impairment charges resulting from our May 31, 2010 impairment testing, and no event indicating an impairment has occurred subsequent to that date. The fair value of each reporting unit was determined from the present value of the expected future cash flows from the applicable reporting unit (inclusive of a terminal value calculated using market multiples between six and ten times cash flows) discounted at a rate of 9.0%. The value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price that would be received to sell the unit as a whole in an orderly transaction between market participants at the measurement date.

Changes in the gross amounts of our goodwill and accumulated impairment losses for the six months ended June 30, 2010 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Terminals	Kinder Morgan Canada	Total
Historical Goodwill.	$ 263.2	$ 337.0	$ 46.1	$ 266.9	$ 613.1	$ 1,526.3
Accumulated impairment losses(a)	-	-	-	-	(377.1)	(377.1)
Balance as of December 31, 2009	263.2	337.0	46.1	266.9	236.0	1,149.2
Acquisitions	-	-	-	58.9	-	58.9
Currency translation adjustments	-	-	-	-	(3.1)	(3.1)
Balance as of June 30, 2010	$ 263.2	$ 337.0	$ 46.1	$ 325.8	$ 232.9	$ 1,205.0

(a) On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from KMI, and we completed this transaction on April 30, 2007. Following the provisions of generally accepted accounting principles, the consideration of this transaction caused KMI 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, KMI 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 is now included in our accumulated impairment losses. We have no other goodwill impairment losses.

In addition, we identify any premium or excess cost we pay over our proportionate share of the underlying fair value of net assets acquired and accounted for as investments under the equity method of accounting. This premium or excess cost is referred to as equity method goodwill and is also not subject to amortization but rather to impairment testing. For all investments we own containing equity method goodwill, no event or change in circumstances that may have a significant adverse effect on the fair value of our equity investments has occurred during the first six months of 2010, and as of both June 30, 2010 and December 31, 2009, we reported $138.2 million in equity method goodwill within the caption "Investments" in our accompanying consolidated balance sheets.

Other Intangibles

Excluding goodwill, our other intangible assets include customer relationships, contracts and agreements, technology-based assets, and lease value. These intangible assets have definite lives 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, 2010	December 31, 2009
Customer relationships, contracts and agreements		
Gross carrying amount	$ 392.2	$ 273.0
Accumulated amortization	(89.2)	(67.1)
Net carrying amount	303.0	205.9
Technology-based assets, lease value and other		
Gross carrying amount	15.7	15.7
Accumulated amortization	(3.2)	(2.9)
Net carrying amount	12.5	12.8
Total Other intangibles, net	$ 315.5	$ 218.7

The increase in the carrying amount of our customer relationships, contracts and agreements since December 31, 2009 was mainly due to the acquisition of intangibles included in our purchase of terminal assets from US Development Group LLC and Slay Industries, discussed in Note 2.

We amortize the costs of our intangible assets to expense in a systematic and rational manner over their estimated useful lives. Among the factors we weigh, depending on the nature of the asset, are the effects of obsolescence, new technology, and competition. For the three and six months ended June 30, 2010, the amortization expense on our intangibles totaled $11.1 million and $22.4 million, respectively, and for the same prior year periods, the amortization expense on our intangibles totaled $3.4 million and $6.9 million, respectively. As of June 30, 2010, the weighted average amortization period for our intangible assets was approximately 14 years, and our estimated amortization expense for these assets for each of the next five fiscal years (2011 – 2015) is approximately $38.7 million, $33.3 million, $29.4 million, $26.1 million and $23.2 million, respectively.

4. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments or as of the earliest put date available to the holders of the applicable debt. We defer costs associated with debt issuance over the applicable term or to the first put date, in the case of debt with a put feature. These costs are then amortized as interest expense in our consolidated statements of income.

The net carrying amount of our debt (including both short-term and long-term amounts and excluding the value of interest rate swap agreements) as of June 30, 2010 and December 31, 2009 was $11,850.8 million and $10,592.4 million, respectively. The weighted average interest rate on all of our borrowings (both short-term and long-term) was approximately 4.33% during the second quarter of 2010 and approximately 4.57% during the second quarter of 2009. For the first six months of 2010 and 2009, the weighted average interest rate on all of our borrowings (both short and long term) was approximately 4.33% and 4.82%, respectively.

Our outstanding short-term debt as of June 30, 2010 was $1,571.1 million. The balance consisted of (i) $700.0 million in principal amount of 6.75% senior notes due March 15, 2011 (including discount, the notes had a carrying amount of $699.9 million as of June 30, 2010); (ii) $501.4 million of commercial paper borrowings; (iii) $250.0 million in principal amount of 7.50% senior notes due November 1, 2010 (including discount, the notes had a carrying amount of $249.9 million as of June 30, 2010); (iv) $75.0 million in outstanding borrowings under our unsecured revolving bank credit facility (discussed following); (v) $23.7 million in principal amount of tax-exempt bonds that mature on April 1, 2024, but are due on demand pursuant to certain standby purchase agreement provisions contained in the bond indenture (our subsidiary Kinder Morgan Operating L.P. "B" is the obligor on the bonds); (vi) a $9.1 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); (vii) a $7.1 million portion of 5.23% long-term senior notes (our subsidiary Kinder Morgan Texas

Pipeline, L.P. is the obligor on the notes); and (viii) $5.0 million in principal amount of 6.00% Development Revenue Bonds due January 1, 2011 and issued by the Louisiana Community Development Authority, a political subdivision of the state of Louisiana (our subsidiary Kinder Morgan Louisiana Pipeline LLC is the obligor on the bonds).

Credit Facility

As of March 31, 2010, we had a $1.79 billion five-year unsecured revolving bank credit facility that was due August 18, 2010. On June 23, 2010, we successfully renegotiated this credit facility, replacing it with a new $2.0 billion three-year, senior unsecured revolving credit facility that expires June 23, 2013. The covenants of this credit facility are substantially similar to the terms of our previous facility; however, the interest rates for borrowings under this facility have increased from our previous facility.

Similar to our previous facility, our $2.0 billion credit facility is with a syndicate of financial institutions, and the facility permits us to obtain bids for fixed rate loans from members of the lending syndicate. Wells Fargo Bank, National Association is the administrative agent, and borrowings under the credit facility can be used for general partnership purposes and as a backup for our commercial paper program. Interest on the credit facility accrues at our option at a floating rate equal to either (i) the administrative agent's base rate (but not less than the Federal Funds Rate, plus 0.5%); or (ii) LIBOR, plus a margin, which varies depending upon the credit rating of our long-term senior unsecured debt. The credit facility can be amended to allow for borrowings of up to $2.3 billion.

The outstanding balance under our $2.0 billion credit facility was $75.0 million as of June 30, 2010, and the weighted average interest rate on these borrowings was 2.10%. As of December 31, 2009, the outstanding balance under our previous $1.79 billion credit facility was $300 million, and the weighted average interest rate on these borrowings was 0.59%.

Additionally, as of June 30, 2010, the amount available for borrowing under our credit facility was reduced by a combined amount of $723.6 million, consisting of $501.4 million of commercial paper borrowings and $222.2 million of letters of credit, consisting of: (i) a $100.0 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) a combined $89.4 million in three letters of credit that support tax-exempt bonds; (iii) a $16.1 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (iv) a combined $16.7 million in other letters of credit supporting other obligations of us and our subsidiaries.

Commercial Paper Program

On October 13, 2008, Standard & Poor's Ratings Services lowered our short-term credit rating to A-3 from A-2, and on May 6, 2009, Moody's Investors Service, Inc. downgraded our commercial paper rating to Prime-3 from Prime-2 and assigned a negative outlook to our long-term credit rating. As a result of these revisions and the commercial paper market conditions, we were unable to access commercial paper borrowings throughout 2009.

However, on February 25, 2010, Standard & Poor's revised its outlook on our long-term credit rating to stable from negative, affirmed our long-term credit rating at BBB, and raised our short-term credit rating to A-2 from A-3. The rating agency's revisions reflected its expectations that our financial profile will improve due to lower guaranteed debt obligations and higher expected cash flows associated with the completion and start-up of our 50%-owned Rockies Express and Midcontinent Express natural gas pipeline systems and our fully-owned Kinder Morgan Louisiana natural gas pipeline system. Due to this favorable change in our short-term credit rating, we resumed issuing commercial paper in March 2010, and as of June 30, 2010, we had $501.4 million of commercial paper outstanding with an average interest rate of approximately 0.67%. In the near term, we expect that our short-term liquidity and financing needs will be met through a combination of borrowings made under our bank credit facility and our commercial paper program.

Senior Notes

On May 19, 2010, we completed a public offering of senior notes. We issued a total of $1 billion in principal amount of senior notes in two separate series, consisting of $600 million of 5.30% notes due September 15, 2020, and $400 million of 6.55% notes due September 15, 2040. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $993.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 6 "Risk Management—Interest Rate Risk Management."

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and 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, 2010.

Cortez Pipeline Company Debt

Pursuant to a Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company (our subsidiary 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, 2010, the debt facilities of Cortez Capital Corporation consisted of (i) $32.1 million of fixed rate Series D notes due May 15, 2013; (ii) $100 million of variable rate Series E notes due December 11, 2012 (interest on the Series E notes is paid quarterly and based on an interest rate of three-month LIBOR plus a spread); and (iii) a $40 million committed revolving credit facility also due December 11, 2012. As of June 30, 2010, in addition to the outstanding Series D and Series E notes, Cortez Capital Corporation had outstanding borrowings of $11.8 million under its credit facility. Accordingly, as of June 30, 2010, our contingent share of Cortez's debt was $72.0 million (50% of total borrowings).

With respect to Cortez's Series D notes, the average interest rate on the notes is 7.14%, and the outstanding $32.1 million principal amount of the notes is due in three equal annual installments of $10.7 million beginning May 2011. Shell Oil Company shares our guaranty obligations jointly and severally; however, we are obligated to indemnify Shell for liabilities it incurs in connection with such guaranty. Accordingly, as of June 30, 2010, JP Morgan Chase has issued a letter of credit on our behalf in the amount of $16.1 million to secure our indemnification obligations to Shell for 50% of the $32.1 million in principal amount of Series D notes outstanding as of that date.

Nassau County, Florida Ocean Highway and Port Authority Debt

We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year, and corresponding reductions are made to the letter of credit. As of June 30, 2010, this letter of credit had a face amount of $19.8 million.

Fayetteville Express Pipeline LLC Debt

Fayetteville Express Pipeline LLC is an equity method investee of ours, and pursuant to certain guaranty agreements with Fayetteville Express Pipeline LLC, both of the member owners of Fayetteville Express Pipeline LLC have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in Fayetteville Express, borrowings under its $1.1 billion, unsecured revolving credit facility that is due May 11, 2012. 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%.

The Fayetteville Express Pipeline LLC credit facility is with a syndicate of financial institutions with The Royal Bank of Scotland plc as the administrative agent. Borrowings under the credit facility are primarily used to finance the construction of the Fayetteville Express natural gas pipeline system and to pay related expenses. As of June 30, 2010, Fayetteville Express had outstanding borrowings of $663.0 million under its bank credit facility. Accordingly, as of June 30, 2010, our contingent share of Fayetteville Express' debt was $331.5 million (50% of total borrowings).

Midcontinent Express Pipeline LLC Debt

Midcontinent Express Pipeline LLC is also an equity method investee of ours, and the three member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan Operating L.P. "A" – 50%; Regency Energy Partners, L.P. – 49.9%; and Energy Transfer Partners, L.P. – 0.1%. Pursuant to certain guaranty agreements, each of the 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 its three-year, unsecured revolving credit facility due February 28, 2011. The facility is with a syndicate of financial institutions with The Royal Bank of Scotland plc as the administrative agent. Borrowings under the credit facility can be used for general limited liability company purposes.

As of March 31, 2010, the credit facility allowed for borrowings up to $255.4 million. On April 30, 2010, Midcontinent Express Pipeline LLC amended its bank credit facility to allow for borrowings up to $175.4 million (a reduction from $255.4 million), and as of June 30, 2010, Midcontinent Express Pipeline LLC had outstanding borrowings of $33.1 million under its bank credit facility. Accordingly, as of June 30, 2010, our contingent share of Midcontinent Express' debt was $16.6 million (50% of total guaranteed borrowings). Furthermore, the credit facility can be used for the issuance of letters of credit to support the operation of the Midcontinent Express pipeline system, and as of June 30, 2010, a letter of credit having a face amount of $33.3 million was issued under the credit facility by the Bank of Tokyo-Mitsubishi UFJ, Ltd. Accordingly, as of June 30, 2010, our contingent responsibility with regard to this outstanding letter of credit was $16.7 million (50% of total face amount).

Rockies Express Pipeline LLC Debt

Rockies Express Pipeline LLC is another equity method investee of ours, and pursuant to certain guaranty agreements remaining in effect on March 31, 2010, all three member owners of Rockies Express Pipeline LLC had agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in Rockies Express Pipeline LLC, borrowings under its $2.0 billion five-year, unsecured revolving bank credit facility due April 28, 2011. The three member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan W2E Pipeline LLC – 50%; a subsidiary of Sempra Energy – 25%; and a subsidiary of ConocoPhillips – 25%.

As of March 31, 2010, Rockies Express Pipeline LLC had no outstanding borrowings under its bank credit facility; therefore, we had no contingent debt obligation associated with our guaranty agreement. On April 8, 2010, Rockies Express Pipeline LLC amended its bank credit facility to allow for borrowings up to $200 million (a reduction from $2.0 billion), and on this same date, each of its three member owners were released from their respective debt obligations under the previous guaranty agreements. Accordingly, we no longer have a contingent debt obligation with respect to Rockies Express Pipeline LLC.

For additional information regarding our debt facilities and our contingent debt agreements, see Note 8 "Debt" and Note 12 "Commitments and Contingent Liabilities" to our consolidated financial statements included in our 2009 Form 10-K.

5. Partners' Capital

Limited Partner Units

As of June 30, 2010 and December 31, 2009, our partners' capital included the following limited partner units:

	June 30, 2010	December 31, 2009
Common units	214,053,605	206,020,826
Class B units	5,313,400	5,313,400
i-units	88,670,863	85,538,263
Total limited partner units	308,037,868	296,872,489

The total limited partner units represent our limited partners' interest and an effective 98% 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, 2010, our total common units consisted of 197,683,177 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner. As of December 31, 2009, our total common units consisted of 189,650,398 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner.

As of both June 30, 2010 and December 31, 2009, all of our 5,313,400 Class B units were held by a wholly-owned subsidiary of KMI. The Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange.

As of both June 30, 2010 and December 31, 2009, all of our i-units were held by KMR. Our i-units are a separate class of limited partner interests in us and are not publicly traded. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common units.

Changes in Partners' Capital

For each of the three and six month periods ended June 30, 2010 and 2009, changes in the carrying amounts of our Partners' Capital attributable to both us and our noncontrolling interests, including our comprehensive income (loss) are summarized as follows (in millions):

	Three Months Ended June 30,					
	2010			2009		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 6,612.6	$ 78.7	$ 6,691.3	$ 6,145.5	$ 71.6	$ 6,217.1
Units issued as consideration in the acquisition of assets	-	-	-	5.0	-	5.0
Units issued for cash	433.1	-	433.1	381.6	-	381.6
Distributions paid in cash	(480.2)	(6.0)	(486.2)	(430.8)	(5.4)	(436.2)
Adjustments to capital resulting from related party acquisitions	-	-	-	20.2	0.3	20.5
KMI going-private transaction expenses	1.3	-	1.3	1.4	-	1.4
Cash contributions	-	5.5	5.5	-	4.8	4.8
Other adjustments	-	-	-	(0.2)	-	(0.2)
Comprehensive income:						
Net Income	361.2	3.9	365.1	323.8	4.8	328.6
Other comprehensive income (loss):						
Change in fair value of derivatives utilized for hedging purposes	141.6	1.5	143.1	(336.1)	(3.4)	(339.5)
Reclassification of change in fair value of derivatives to net income	39.1	0.4	39.5	30.3	0.3	30.6
Foreign currency translation adjustments	(85.5)	(0.9)	(86.4)	127.1	1.3	128.4
Adjustments to pension and other postretirement benefit plan liabilities	(0.1)	-	(0.1)	(0.1)	-	(0.1)
Total other comprehensive income (loss)	95.1	1.0	96.1	(178.8)	(1.8)	(180.6)
Comprehensive income	456.3	4.9	461.2	145.0	3.0	148.0
Ending Balance	$ 7,023.1	$ 83.1	$ 7,106.2	$ 6,267.7	$ 74.3	$ 6,342.0

	Six Months Ended June 30,					
	2010			2009		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 6,644.5	$ 79.6	$ 6,724.1	$ 6,045.6	$ 70.7	$ 6,116.3
Units issued as consideration pursuant to common unit compensation plan for non-employee directors	0.2	-	0.2	0.2	-	0.2
Units issued as consideration in the acquisition of assets	81.7	-	81.7	5.0	-	5.0
Units issued for cash	433.1	-	433.1	669.2	-	669.2
Distributions paid in cash	(949.0)	(12.0)	(961.0)	(848.1)	(10.8)	(858.9)
Adjustments to capital resulting from related party acquisitions	-	-	-	22.9	0.3	23.2
KMI going-private transaction expenses	2.7	-	2.7	2.8	-	2.8
Cash contributions	-	7.2	7.2	-	8.6	8.6
Other adjustments	-	-	-	(0.2)	-	(0.2)
Comprehensive income:						
Net Income	586.5	6.0	592.5	587.7	7.7	595.4
Other comprehensive income (loss):						
Change in fair value of derivatives utilized for hedging purposes	166.0	1.7	167.7	(300.6)	(3.0)	(303.6)
Reclassification of change in fair value of derivatives to net income	86.1	0.9	87.0	13.2	0.1	13.3
Foreign currency translation adjustments	(26.3)	(0.3)	(26.6)	72.9	0.7	73.6
Adjustments to pension and other postretirement benefit plan liabilities	(2.4)	-	(2.4)	(2.9)	-	(2.9)
Total other comprehensive income (loss)	223.4	2.3	225.7	(217.4)	(2.2)	(219.6)
Comprehensive income	809.9	8.3	818.2	370.3	5.5	375.8
Ending Balance	$ 7,023.1	$ 83.1	$ 7,106.2	$ 6,267.7	$ 74.3	$ 6,342.0

During the first six months of both 2010 and 2009, there were no material changes in our ownership interests in subsidiaries in which we retained a controlling financial interest.

Equity Issuances

On January 15, 2010, we issued 1,287,287 common units as part of our purchase price for the ethanol handling terminal assets we acquired from US Development Group LLC. We valued the common units at $81.7 million, determining the units' value based on the $63.45 closing market price of the common units on the New York Stock Exchange on the January 15, 2010 acquisition date. For more information on this acquisition, see Note 2 "Acquisitions, Joint Ventures, and Divestitures—Acquisitions—USD Terminal Acquisition."

On May 7, 2010, we issued, in a public offering, 6,500,000 of our common units at a price of $66.25 per unit, less commissions and underwriting expenses. After commissions and underwriting expenses, we received net proceeds of $417.4 million for the issuance of these 6,500,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

In June 2010, we issued 243,042 of our common units pursuant to our equity distribution agreement with UBS Securities LLC (UBS). After commissions of $0.1 million, we received net proceeds from the issuance of these common units of $15.8 million, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility. Our equity distribution agreement provides us the right, but not the obligation, to sell common units in the future, at prices we deem appropriate. We retain at all times complete control over the amount and the timing of each sale, and we will designate the maximum number of common units to be sold through UBS, on a daily basis or otherwise as we and UBS agree. Either we or UBS may suspend the offering of common units pursuant to the agreement by notifying the other party. For additional information regarding our equity distribution agreement, see Note 9 to our consolidated financial statements included in our 2009 Form 10-K.

Equity Issuances Subsequent to June 30, 2010

On July 1, 2010, we issued 47,800 of our common units for the settlement of sales made before June 30, 2010 pursuant to our equity distribution agreement. After commissions of $0.1 million, we received net proceeds of $3.1 million for the issuance of these 47,800 common units, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

Also, on July 2, 2010, we completed an offering of 1,167,315 of our common units at a price of $64.25 per unit in a privately negotiated transaction. We received net proceeds of $75.0 million for the issuance of these 1,167,315 common units, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

Income Allocation and Declared Distributions

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

On May 14, 2010, we paid a cash distribution of $1.07 per unit to our common unitholders and our Class B unitholders for the quarterly period ended March 31, 2010. KMR, our sole i-unitholder, received a distribution of 1,556,130 i-units from us on May 14, 2010, based on the $1.07 per unit distributed to our common unitholders on that date. The distributions were declared on April 21, 2010, payable to unitholders of record as of April 30, 2010.

Incentive distributions allocated to our general partner are determined by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of our partnership agreement. Our distribution of $1.07 per unit paid on May 14, 2010 for the first quarter of 2010 required an incentive distribution to our general partner of $249.4 million. Our distribution of $1.05 per unit paid on May 15, 2009 for the first quarter of 2009 resulted in an incentive distribution payment to our general partner in the amount of $223.2 million. The increased incentive distribution to our general partner paid for the first quarter of 2010 over the incentive distribution paid for the first quarter of 2009 reflects the increase in the amount distributed per unit as well as the issuance of additional units.

Subsequent Event

On July 21, 2010, we declared a cash distribution of $1.09 per unit for the quarterly period ended June 30, 2010. The distribution will be paid on August 13, 2010, to unitholders of record as of July 30, 2010. Our common unitholders and Class B unitholders will receive cash. KMR will receive a distribution of 1,625,869 additional i-units based on the $1.09 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.018336) will be issued. This fraction was determined by dividing:

▪ $1.09, the cash amount distributed per common unit

by

▪ $59.446, the average of KMR’s shares’ closing market prices from July 14-27, 2010, 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.

Our declared distribution for the second quarter of 2010 of $1.09 per unit will result in an incentive distribution to our general partner of $89.8 million. This compares to our distribution of $1.05 per unit and incentive distribution to our general partner of $231.8 million for the second quarter of 2009. Under the terms of our partnership agreement, our declared distributions to unitholders for the second quarter of 2010 required incentive distributions to our general partner in the amount of $263.4 million. However, our general partner’s incentive distribution was reduced by a combined

$173.6 million, including (i) a waived incentive amount equal to $5.3 million related to equity issued to finance our acquisition of a 50% interest in Petrohawk Energy Corporation's natural gas gathering and treating business (described in Note 2); and (ii) a reduced incentive amount of $168.3 million (including its 2% general partner's interest, total cash distributions were reduced $170.0 million), due to a portion of our cash distributions for the second quarter of 2010 being a distribution of cash from interim capital transactions (ICT Distribution), rather than a distribution of cash from operations. As provided in our partnership agreement, our general partner receives no incentive distribution on ICT Distributions.

6. Risk Management

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

Energy Commodity Price Risk Management

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

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

For derivative contracts that are designated and qualify as cash flow hedges pursuant to generally accepted accounting principles, the portion of the gain or loss on the derivative contract that is effective in offsetting the variable cash flows associated with the hedged forecasted transaction is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction and in the same period or periods during which the hedged transaction affects earnings (e.g., in "revenues" when the hedged transactions are commodity sales). The remaining gain or loss on the derivative contract in excess of the cumulative change in the present value of future cash flows of the hedged item, if any (i.e., the ineffective portion), is recognized in earnings during the current period. The effectiveness of hedges using an option contract may be assessed based on changes in the option's intrinsic value with the change in the time value of the contract being excluded from the assessment of hedge effectiveness. Changes in the excluded component of the change in an option's time value are included currently in earnings. During the three and six months ended June 30, 2010, we recognized net gains of $7.8 million and $14.1 million, respectively, related to crude oil and natural gas hedges and resulting from hedge ineffectiveness and amounts excluded from effectiveness testing. We recognized no gains or losses resulting from hedge ineffectiveness during the first six months of 2009.

Additionally, during the three and six months ended June 30, 2010, we reclassified losses of $39.5 million and $87.0 million, respectively, from "Accumulated other comprehensive loss" into earnings, and for the same comparable periods last year, we reclassified losses of $30.6 million and $13.3 million, respectively, into earnings. No material amounts were reclassified into earnings as a result of the discontinuance of cash flow hedges because it was probable that the original forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter, but rather, were reclassified as a result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchase actually occurred). The proceeds or payments resulting from the settlement of our cash flow hedges are reflected in the operating section of our statement of cash flows as changes to net income and working capital.

The "Accumulated other comprehensive loss" balance included in our Partners' Capital was $171.4 million as of June 30, 2010, and $394.8 million as of December 31, 2009. These totals included "Accumulated other comprehensive loss" amounts associated with energy commodity price risk management activities of $166.1 million as of June 30, 2010 and $418.2 million as of December 31, 2009. Approximately $137.3 million of the total loss amount associated with energy commodity price risk management activities and included in our Partners' Capital as of June 30, 2010 is expected to be reclassified into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur), and as of June 30, 2010, the maximum length of time over which we have hedged our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2014.

As of June 30, 2010, we had entered into the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)
Derivatives designated as hedging contracts	
Crude oil	(22.2) million barrels
Natural gas fixed price	(34.3) billion cubic feet
Natural gas basis	(28.1) billion cubic feet
Derivatives not designated as hedging contracts	
Natural gas fixed price	(0.2) billion cubic feet
Natural gas basis	0.8 billion cubic feet

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

Interest Rate Risk Management

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

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

As of December 31, 2009, we had a combined notional principal amount of $5.2 billion of fixed-to-variable interest rate swap agreements effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread. In the second quarter of 2010, we entered into three additional fixed-to-variable interest rate swap agreements having a combined notional principal amount of $400 million. Each agreement effectively converts a portion of the interest expense associated with our 5.30% senior notes due September 15, 2020 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread.

Accordingly, as of June 30, 2010, we had a combined notional principal amount of $5.6 billion of fixed-to-variable interest rate swap agreements. 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, 2010, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through January 15, 2038.

Fair Value of Derivative Contracts

The fair values of our current and non-current asset and liability derivative contracts are each reported separately as "Fair value of derivative contracts" on our accompanying consolidated balance sheets. The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of June 30, 2010 and December 31, 2009 (in millions):

Fair Value of Derivative Contracts

	Asset derivatives				Liability derivatives			
	June 30, 2010		December 31, 2009		June 30, 2010		December 31, 2009	
	Balance sheet location	Fair value	Balance sheet location	Fair value	Balance Sheet location	Fair value	Balance sheet Location	Fair Value
Derivatives designated as hedging contracts								
Energy commodity derivative contracts	Current	$ 36.0	Current	$ 19.1	Current	$ (180.7)	Current	$ (270.8)
	Non-current	84.8	Non-current	57.3	Non-current	(108.9)	Non-current	(241.5)
Subtotal		120.8		76.4		(289.6)		(512.3)
Interest rate swap agreements	Non-current	459.6	Non-current	222.5	Non-current	(41.4)	Non-current	(218.6)
Total		580.4		298.9		(331.0)		(730.9)
Derivatives not designated as hedging contracts								
Energy commodity derivative contracts	Current	8.5	Current	1.7	Current	(8.4)	Current	(1.2)
	Non-current	-	Non-current	-	Non-current	-	Non-current	-
Total		8.5		1.7		(8.4)		(1.2)
Total derivatives		$ 588.9		$ 300.6		$ (339.4)		$ (732.1)

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, 2010 and December 31, 2009, this unamortized premium totaled $319.3 million and $328.6 million, respectively.

Effect of Derivative Contracts on the Income Statement

The following three tables summarize the impact of our derivative contracts on our accompanying consolidated statements of income for each of the three and six months ended June 30, 2010 and 2009 (in millions):

Derivatives in fair value hedging relationships	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative(a)		Hedged items in fair value hedging relationships	Location of gain/(loss) recognized in income on related hedged item	Amount of gain/(loss) recognized in income on related hedged items(a)	
		Three Months Ended June 30,				Three Months Ended June 30,	
		2010	2009			2010	2009
Interest rate swap agreements	Interest, net – income/(expense)	$ 348.6	$ (339.4)	Fixed rate debt	Interest, net – income/(expense)	$ (348.6)	$ 339.4
Total		$ 348.6	$ (339.4)	Total		$ (348.6)	$ 339.4
		Six Months Ended June 30,				Six Months Ended June 30,	
		2010	2009			2010	2009
Interest rate swap agreements	Interest, net – income/(expense)	$ 414.2	$ (469.8)	Fixed rate debt	Interest, net – income/(expense)	$ (414.2)	$ 469.8
Total		$ 414.2	$ (469.8)	Total		$ (414.2)	$ 469.8

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

Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)		Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)		Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	
	Three Months Ended June 30,			Three Months Ended June 30,			Three Months Ended June 30,	
	2010	2009		2010	2009		2010	2009
Energy commodity derivative contracts	$ 143.1	$ (339.5)	Revenues-natural gas sales	$ 1.7	$ 4.8	Revenues-product sales and other	$ 7.9	$ -
			Revenues-product sales and other	(48.4)	(28.9)			
			Gas purchases and other costs of sales	7.2	(6.5)	Gas purchases and other costs of sales	(0.1)	-
Total	$ 143.1	$ (339.5)	Total	$ (39.5)	$ (30.6)	Total	$ 7.8	$ -
	Six Months Ended June 30,			Six Months Ended June 30,			Six Months Ended June 30,	
	2010	2009		2010	2009		2010	2009
Energy commodity derivative contracts	$ 167.7	$ (303.6)	Revenues-natural gas sales	$ 1.7	$ 6.5	Revenues-product sales and other	$ 13.3	$ -
			Revenues-product sales and other	(98.4)	(12.9)			
			Gas purchases and other costs of sales	9.7	(6.9)	Gas purchases and other costs of sales	0.8	-
Total	$ 167.7	$ (303.6)	Total	$ (87.0)	$ (13.3)	Total	$ 14.1	$ -

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Derivatives not designated as hedging contracts	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative	
		Three Months Ended June 30,	
		2010	2009
Energy commodity derivative contracts	Gas purchases and other costs of sales	$ 0.1	$ (1.9)
Total		$ 0.1	$ (1.9)
		Six Months Ended June 30,	
		2010	2009
Energy commodity derivative contracts	Gas purchases and other costs of sales	$ 0.8	$ (2.3)
Total		$ 0.8	$ (2.3)

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Credit Risks

We have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

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

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

The maximum potential exposure to credit losses on our derivative contracts as of June 30, 2010 was (in millions):

	Asset position
Interest rate swap agreements	$ 459.6
Energy commodity derivative contracts	129.3
Gross exposure	588.9
Netting agreement impact	(93.6)
Net exposure	$ 495.3

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 December 31, 2009, we had outstanding letters of credit totaling $55.0 million in support of our hedging of energy commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil. As of June 30, 2010 and December 31, 2009, we had cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners totaling $19.3 million and $15.2 million, respectively, and we reported these amounts as “Restricted deposits” in our accompanying consolidated balance sheets.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring us to post additional collateral upon a decrease in our credit rating. Based on contractual provisions as of June 30, 2010, we estimate that if our credit rating was downgraded, we would have the following additional collateral obligations (in millions):

Credit ratings downgraded(a)	Incremental obligations	Cumulative obligations(b)
One notch to BBB-/Baa3	$ 3.7	$ 23.0
Two notches to below BBB-/Baa3 (below investment grade)	$ 90.8	$ 113.8

(a) If there are split ratings among the independent credit rating agencies, most counterparties use the higher credit rating to determine our incremental collateral obligations, while the remaining use the lower credit rating. Therefore, a one notch downgrade to BBB-/Baa3 by one agency would not trigger the entire $3.7 million incremental obligation.

(b) Includes current posting at current rating.

7. Fair Value

The Codification emphasizes that fair value is a market-based measurement that should be determined based on assumptions (inputs) that market participants would use in pricing an asset or liability. Inputs may be observable or unobservable, and valuation techniques used to measure fair value should maximize the use of relevant observable inputs and minimize the use of unobservable inputs. Accordingly, the Codification establishes a hierarchal disclosure framework that ranks the quality and reliability of information used to determine fair values. The hierarchy is associated with the level of pricing observability utilized in measuring fair value and defines three levels of inputs to the fair value measurement process—quoted prices are the most reliable valuation inputs, whereas model values that include inputs based on unobservable data are the least reliable. Each fair value measurement must 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 fair value 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).

Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts; and (ii) interest rate swap agreements as of June 30, 2010 and December 31, 2009, based on the three levels established by the Codification (in millions):

	Asset fair value measurements using			
	Total	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
As of June 30, 2010				
Energy commodity derivative contracts(a)	$ 129.3	$ -	$ 55.1	$ 74.2
Interest rate swap agreements	$ 459.6	$ -	$ 459.6	$ -
As of December 31, 2009				
Energy commodity derivative contracts(a)	$ 78.1	$ -	$ 14.4	$ 63.7
Interest rate swap agreements	$ 222.5	$ -	$ 222.5	$ -

	Liability fair value measurements using			
	Total	**Quoted prices in active markets for identical liabilities (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
As of June 30, 2010				
Energy commodity derivative contracts(b)	$ (298.0)	$ -	$ (270.4)	$ (27.6)
Interest rate swap agreements	$ (41.4)	$ -	$ (41.4)	$ -
As of December 31, 2009				
Energy commodity derivative contracts(b)	$ (513.5)	$ -	$ (462.8)	$ (50.7)
Interest rate swap agreements	$ (218.6)	$ -	$ (218.6)	$ -

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

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

The fair value measurements in the tables above do not include cash margin deposits, which are reported separately as "Restricted deposits" in our accompanying consolidated balance sheets. The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for each of the three and six months ended June 30, 2010 and 2009 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Derivatives-net asset (liability)				
Beginning of Period	$ 22.6	$ 53.4	$ 13.0	$ 44.1
Realized and unrealized net gains and (losses)	18.1	(28.1)	26.7	(21.8)
Purchases and settlements	5.9	(1.3)	6.9	1.7
Transfers in (out) of Level 3	-	-	-	-
End of Period	$ 46.6	$ 24.0	$ 46.6	$ 24.0
Change in unrealized net losses relating to contracts still held at end of period	$ 19.2	$ (29.7)	$ 24.1	$ (39.5)

Fair Value of Financial Instruments

Fair value as used in the disclosure of financial instruments represents the amount at which an instrument could be exchanged in a current transaction between willing parties. As of each reporting date, the estimated fair value of our outstanding publicly-traded debt is based upon quoted market prices, if available, and for all other debt, fair value is based upon prevailing interest rates currently available to us. In addition, we adjust (discount) the fair value measurement of our long-term debt for the effect of credit risk.

The estimated fair value of our outstanding debt balance as of June 30, 2010 and December 31, 2009 (both short-term and long-term, but excluding the value of interest rate swaps), is disclosed below (in millions):

	June 30, 2010		December 31, 2009	
	Carrying Value	Estimated fair value	Carrying value	Estimated fair value
Total Debt	$ 11,850.8	$ 12,678.9	$ 10,592.4	$ 11,265.7

8. Reportable Segments

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

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

We evaluate performance principally based on each segments' earnings before depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments), which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income, and unallocable 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.

Financial information by segment follows (in millions):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenues				
Products Pipelines				
Revenues from external customers	$ 226.3	$ 206.7	$ 433.8	$ 394.9
Natural Gas Pipelines				
Revenues from external customers	1,029.7	860.7	2,266.4	1,912.4
CO_2				
Revenues from external customers	314.6	258.2	636.4	487.1
Terminals				
Revenues from external customers	320.3	263.7	624.1	531.4
Intersegment revenues	0.2	0.3	0.5	0.5
Kinder Morgan Canada				
Revenues from external customers	70.6	56.0	130.4	106.0
Total segment revenues	1,961.7	1,645.6	4,091.6	3,432.3
Less: Total intersegment revenues	(0.2)	(0.3)	(0.5)	(0.5)
Total consolidated revenues	$ 1,961.5	$ 1,645.3	$ 4,091.1	$ 3,431.8

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 165.2	$ 155.0	$ 171.6	$ 300.4
Natural Gas Pipelines	185.0	162.1	405.6	362.9
CO_2	249.4	202.7	502.6	370.1
Terminals	165.5	142.9	316.0	277.6
Kinder Morgan Canada	43.9	46.7	88.9	66.2
Total segment earnings before DD&A	809.0	709.4	1,484.7	1,377.2
Total segment depreciation, depletion and amortization	(223.2)	(203.1)	(450.5)	(413.3)
Total segment amortization of excess cost of investments	(1.5)	(1.5)	(2.9)	(2.9)
General and administrative expenses	(93.4)	(72.6)	(194.5)	(155.1)
Unallocable interest expense, net of interest income	(123.8)	(101.3)	(240.1)	(205.9)
Unallocable income tax expense	(2.0)	(2.3)	(4.2)	(4.6)
Total consolidated net income	$ 365.1	$ 328.6	$ 592.5	$ 595.4

	June 30, 2010	December 31, 2009
Assets		
Products Pipelines	$ 4,314.3	$ 4,299.0
Natural Gas Pipelines	8,789.8	7,772.7
CO_2	2,195.3	2,224.5
Terminals	3,986.8	3,636.6
Kinder Morgan Canada	1,761.0	1,797.7
Total segment assets	21,047.2	19,730.5
Corporate assets(c)	781.1	531.7
Total consolidated assets	$ 21,828.3	$ 20,262.2

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

(b) Six month 2010 amount includes a $158.0 million increase in expense associated with rate case liability adjustments. Following the Federal Regulatory Energy Commission's approval of a settlement agreement we reached with certain shippers, we made settlement payments totaling $206.3 million in June 2010. For more information on our rate case proceedings, see Note 10.

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

9. Related Party Transactions

Notes Receivable

Plantation Pipe Line Company

We have a long-term note receivable bearing interest at the rate of 4.72% per annum from Plantation Pipe Line Company, our 51.17%-owned equity investee. The note provides for semiannual payments of principal and interest on June 30 and December 31 each year, with a final principal payment due July 20, 2011. We received a principal repayment amount of $1.3 million in June 2010. The outstanding note receivable balance was $83.5 million as of June 30, 2010 and $84.8 million as of December 31, 2009. We included $2.7 million and $2.6 million within "Accounts, notes and interest receivable, net," on our accompanying consolidated balance sheets as of June 30, 2010 and December 31, 2009, respectively, and the remaining outstanding balance was included within "Notes receivable" at each reporting date.

Express US Holdings LP

In conjunction with the acquisition of our 33 1/3% equity ownership interest in the Express pipeline system from KMI on August 28, 2008, we acquired a long-term investment in a C$113.6 million debt security issued by Express US Holdings LP (the obligor), the partnership that maintains ownership of the U.S. portion of the Express pipeline system. The debenture is denominated in Canadian dollars, due in full on January 9, 2023, bears interest at the rate of 12.0% per annum, and provides for quarterly payments of interest in Canadian dollars on March 31, June 30, September 30 and December 31 each year. As of June 30, 2010 and December 31, 2009, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was $106.7 million and $108.1 million, respectively, and we included these amounts within "Notes receivable" on our accompanying consolidated balance sheets.

Other Receivables and Payables

As of June 30, 2010 and December 31, 2009, our related party receivables (other than notes receivable discussed above in "—Notes Receivable") totaled $3.8 million and $13.8 million, respectively. The June 30, 2010 amount consisted of (i) $3.7 million included within "Accounts, notes and interest receivable, net" and primarily related to receivables due from the Express pipeline system and Natural Gas Pipeline Company of America LLC, a 20%-owned equity investee of KMI and referred to in this report as NGPL; and (ii) $0.1 million of natural gas imbalance receivables, included within "Other current assets" and consisting of amounts due from Rockies Express Pipeline LLC. The December 31, 2009 amount consisted of (i) $10.7 million included within "Accounts, notes and interest receivable, net" and primarily related to receivables due from the Express pipeline system and NGPL; and (ii) $3.1 million of natural gas imbalance receivables, primarily due from NGPL and included within "Other current assets."

As of June 30, 2010 and December 31, 2009, our related party payables totaled $9.2 million and $13.4 million, respectively. The June 30, 2010 amount consisted of (i) $6.3 million included within "Accounts payable" and primarily related to payables due to Plantation Pipe Line Company and KMI; and (ii) $2.9 million of natural gas imbalance payables, included within "Accrued other current liabilities" and consisting of amounts due to NGPL. The December 31, 2009 related party payable amounts are included within "Accounts payable" on our accompanying balance sheet, and primarily consisted of amounts we owed to KMI.

Asset Acquisitions

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

Derivative Counterparties

As a result of KMI's going-private transaction, a number of individuals and entities became significant investors in KMI, and by virtue of the size of its ownership interest in KMI, one of those investors—Goldman Sachs Capital Partners and certain of its affiliates—remains a "related party" (as that term is defined in authoritative accounting literature) to us as of June 30, 2010. Goldman Sachs has also acted in the past, and may act in the future, as an underwriter for equity and/or debt issuances for us, and Goldman Sachs effectively owned 49% of the terminal assets we acquired from US Development Group LLC (discussed in Note 2).

In addition, we conduct energy 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, and 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. The hedging facility 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 J. Aron & Company/Goldman Sachs; and (ii) included within "Fair value of derivative contracts" on our accompanying consolidated balance sheets as of June 30, 2010 and December 31, 2009 (in millions):

	June 30, 2010	December 31, 2009
Derivatives – asset/(liability)		
Current assets	$ 0.4	$ 4.3
Noncurrent assets	$ 22.4	$ 18.4
Current liabilities	$ (84.2)	$ (96.8)
Noncurrent liabilities	$ (82.5)	$ (190.8)

For more information on our risk management activities see Note 6.

Other

Generally, KMR makes all decisions relating to the management and control of our business, and in general, KMR has a fiduciary duty to manage us in a manner beneficial to our unitholders. Our general partner owns all of KMR's voting securities and elects all of KMR's directors. KMI, through its wholly owned and controlled subsidiary Kinder Morgan (Delaware), Inc., owns all the common stock of our general partner, and the officers of KMI have fiduciary duties to manage KMI, including selection and management of its investments in its subsidiaries and affiliates, in a manner beneficial to the owners of KMI.

Accordingly, certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, KMI and us. The partnership agreements for us and our operating partnerships contain provisions that allow KMR to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duty to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty. The partnership agreements also provide that in the absence of bad faith by KMR, the resolution of a conflict by KMR will not be a breach of any duties. The duty of the officers of KMI may, therefore, come into conflict with the duties of KMR and its directors and officers to our unitholders. The audit committee of KMR's board of directors will, at the request of KMR, review (and is one of the means for resolving) conflicts of interest that may arise between KMI or its subsidiaries, on the one hand, and us, on the other hand.

For a more complete discussion of our related party transactions, including (i) the accounting for our general and administrative expenses; (ii) KMI's operation and maintenance of the assets comprising our Natural Gas Pipelines business segment; and (iii) our partnership interests and distributions, see Note 11 to our consolidated financial statements included in our 2009 Form 10-K.

10. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during the six months ended June 30, 2010. Additional information with respect to these proceedings can be found in Note 16 to our consolidated financial statements that were included in our 2009 Form 10-K. This note also contains a description of any material legal proceedings that were initiated against us during the six months ended June 30, 2010, and a description of any material events occurring subsequent to June 30, 2010 but before the filing of this report.

In this note, we refer to our subsidiary SFPP, L.P. as SFPP; our subsidiary Calnev Pipe Line LLC as Calnev; Chevron Products Company as Chevron; Navajo Refining Company, L.P. as Navajo; BP West Coast Products, LLC as BP; ConocoPhillips Company as ConocoPhillips; Tesoro Refining and Marketing Company as Tesoro; Texaco Refining and Marketing Inc. as Texaco; Western Refining Company, L.P. as Western Refining; ExxonMobil Oil Corporation as ExxonMobil; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airlines; our subsidiary Kinder Morgan CO_2 Company, L.P. (the successor to Shell CO_2 Company, Ltd.) as Kinder Morgan CO_2; the United States Court of Appeals for the District of Columbia Circuit as the D.C. Circuit; the Federal Energy Regulatory Commission as the FERC; the California Public Utilities Commission as the CPUC; the United States Department of the Interior, Minerals Management Service as the MMS; the Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company) as UPRR; the Texas Commission of Environmental Quality as the TCEQ; the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration as the PHMSA; the Florida Department of Environmental Protection as the Florida DEP; our subsidiary Kinder Morgan Bulk Terminals, Inc. as KMBT; our subsidiary Kinder Morgan Port Manatee Terminal LLC as KM PMT; Rockies Express Pipeline LLC as Rockies Express; and Plantation Pipe Line Company as Plantation. “OR” dockets designate complaint proceedings, and “IS” dockets designate protest proceedings.

Federal Energy Regulatory Commission Proceedings

The tariffs and rates charged by SFPP and Calnev are subject to numerous ongoing proceedings at the FERC, including the shippers' complaints and protests regarding interstate rates on the pipeline systems listed below. These complaints and protests have been filed over numerous years beginning in 1992 through and including 2009. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable. If the shippers are successful in proving their claims, they are entitled to seek reparations (which may reach up to two years prior to the filing of their complaints) or refunds of any excess rates paid, and SFPP may be required to reduce its rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts.

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

SFPP

During 2009, SFPP made settlement payments to various shippers totaling approximately $15.5 million in connection with OR07-8, OR07-11, and IS08-28 and related dockets. The IS08-28 settlement (East Line rates) was approved by the FERC in March 2009, and SFPP implemented reduced settlement rates effective May 1, 2009, along with refunds and settlement payments. Due to reduced East Line volumes, SFPP terminated the IS08-28 settlement pursuant to its terms and filed for increased East Line rates (IS09-437), which were accepted and became effective January 1, 2010, subject to refund and investigation.

On May 28, 2010 the FERC approved a settlement agreement with eleven of twelve shippers regarding various rate challenges previously filed with the FERC dating back to 1992 (Historical Cases Settlement). The Historical Cases Settlement resolves all but two of the cases outstanding between SFPP and the eleven shippers and leaves unaffected settlements entered into previously. SFPP does not expect any material adverse impacts from the remaining two unsettled cases with the eleven shippers. Following the FERC's approval of the agreement, we made settlement payments totaling $206.3 million to the eleven shippers in June 2010. The eleven shippers in the Historical Cases Settlement are: Valero; ConocoPhillips; BP; ExxonMobil; Western Refining; Navajo; Tesoro; and the Airlines (four collectively). Chevron is the only shipper who is not a party to the Historical Cases Settlement. Chevron's dockets remain open and pending before the FERC.

This settlement agreement and other legal reserves related to SFPP rate litigation resulted in a $158.0 million charge to earnings in the first quarter of 2010. From a cash perspective, a portion of our partnership distributions for the second quarter of 2010 (which we will pay in the third quarter of 2010) will be a distribution of cash from interim capital transactions (ICT Distribution), rather than a distribution of cash from operations. As a result, our general partner's distribution will be reduced by $170.0 million for the second quarter of 2010. As provided in our partnership agreement, our general partner receives no incentive distribution on ICT Distributions; therefore, there will be no practical impact to our limited partners from this ICT Distribution because (i) the expected cash distribution to the limited partners will not change; (ii) fewer dollars in the aggregate will be distributed, because there is no incentive distribution paid to the general partner related to the portion of the quarterly distribution that is an ICT Distribution; and (iii) our general partner, in this instance, has agreed to waive any resetting of the incentive distribution target levels, as would otherwise occur according to our partnership agreement.

Our second quarter ICT Distribution is expected to allow us to resolve our remaining FERC rate cases (discussed above) and CPUC rate cases (discussed below) without impacting future distributions, and due to the support of our general partner, we still expect to distribute $4.40 in distributions per unit to our limited partners for 2010. The Historical Cases Settlement resolved the following dockets in their entirety: OR94-3, OR95-5, OR95-34, OR96-10, OR96-15, OR96-17, OR97-2, OR98-2, OR98-13, OR00-7, OR00-8, OR00-9, OR00-10, OR04-3, OR05 4, OR05-5, OR07-1, OR07-2, OR07-6, OR07-20, OR08-13, OR08-15, OR09-12, OR09 18, OR09-21, OR09-22, IS99-144, IS00-379, IS04-323, IS07-229.

The following dockets are settled by the Historical Cases Settlement as to the eleven shippers but are pending as to Chevron:

- FERC Docket Nos. OR92-8, et al. (West and East Line Rates)—Chevron protests of compliance filings pending with FERC and appeals pending at the D.C. Circuit;
- FERC Docket Nos. OR96-2, et al. (All SFPP Rates)—Chevron (as a successor-in-interest to Texaco) protests of compliance filings pending with FERC;
- FERC Docket No. OR02-4 (All SFPP Rates)—Chevron appeal of complaint dismissal pending at the D.C. Circuit;
- FERC Docket No. OR03-5 (West, East, North, and Oregon Line Rates)—Chevron exceptions to initial decision pending at FERC;
- FERC Docket No. OR07-4 (All SFPP Rates)—Chevron complaint held in abeyance;
- FERC Docket No. OR09-8 (consolidated) (2008 Index Increases)—Hearing regarding Chevron complaint held in abeyance pending settlement discussions;
- FERC Docket No. IS98-1 (Sepulveda Line Rates)—Chevron protests to compliance filing pending at FERC;
- FERC Docket No. IS05-230 (North Line Rates)—Chevron exceptions to initial decision pending at FERC;
- FERC Docket No. IS07-116 (Sepulveda Line Rates)—Chevron protest subject to resolution of IS98-1 proceeding;
- FERC Docket No. IS08-137 (West and East Line Rates)—Chevron protest subject to resolution of the OR92-8/OR96-2 proceeding;
- FERC Docket No. IS08-302 (2008 Index Rate Increases)—Chevron protest subject to the resolution of proceedings regarding the West, North and Sepulveda Lines;
- FERC Docket No. IS09-375 (2009 Index Rate Increases)—Chevron protest subject to resolution of proceedings regarding the North, West and Sepulveda Lines;

The following dockets are unaffected by the Historical Cases Settlement:

- FERC Docket No. IS08-390 (West Line Rates)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines—Status: Exceptions to initial decision pending at FERC;

- FERC Docket No. IS09-437 (East Line Rates)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero, Chevron, Western Refining, and Southwest Airlines—Status: Hearing stage.

The following dockets terminated independent of the Historical Cases Settlement:

- FERC Docket No. OR07-3 (2005-2006 North Line Index Rate Increases)—Protestants: BP, ExxonMobil, Tesoro, Valero Marketing, Chevron—Defendant: SFPP—Status: Petition for review at D.C. Circuit denied, mandate issued.

- FERC Docket No. OR09-16 (not consolidated) (2007 and 2008 Page 700 Audit Request)—Complainants: Tesoro—Defendant: SFPP—Status: Dismissed at FERC; no appeal taken; and

- FERC Docket No. OR09-17 (Most SFPP Rates) (not consolidated)—Complainants: Tesoro—Defendant: SFPP—Status: Dismissed at FERC; no appeal taken.

Calnev

- FERC Docket Nos. OR07-7, OR07-18, OR07-19 & OR07-22 (not consolidated) (Calnev Rates)—Complainants: Tesoro, Airlines, BP, Chevron, ConocoPhillips and Valero Marketing—Status: Complaint amendments pending before FERC;

- FERC Docket No. IS09-377 (2009 Index Rate Increases)— Protestants: BP, Chevron, and Tesoro—Status: Requests for rehearing of FERC dismissal pending before FERC;

- FERC Docket Nos. OR09-11/OR09-14 (not consolidated) (2007 and 2008 Page 700 Audit Request)—Complainants: BP/Tesoro—Status: BP petition for review at D.C. Circuit dismissed, mandate issued;

- FERC Docket Nos. OR09-15/OR09-20 (not consolidated) (Calnev Rates)—Complainants: Tesoro/BP—Status: Complaints pending at FERC;

- FERC Docket Nos. OR09-18/OR09-22 (not consolidated) (2009 Index Increases)—Complainants: Tesoro/BP—Status: BP petition for review at D.C. Circuit dismissed, mandate issued.

Trailblazer Pipeline Company LLC

On July 7, 2010, our subsidiary Trailblazer Pipeline Company LLC refunded a total of approximately $0.7 million to natural gas shippers covering the period January 1, 2010 through May 31, 2010 as part of a settlement reached with shippers to eliminate the December 1, 2009 rate filing obligation contained in its Docket No. RP03-162 rate case settlement. As part of the agreement with shippers, Trailblazer commenced billing reduced tariff rates as of June 1, 2010 with an additional reduction in tariff raters to take effect January 1, 2011.

California Public Utilities Commission Proceedings

SFPP has previously reported ratemaking and complaint proceedings pending with the CPUC. The ratemaking and complaint cases generally involve challenges to rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and request prospective rate adjustments and refunds with respect to tariffed and previously untariffed charges for certain pipeline transportation and related services. These matters have been consolidated and assigned to two administrative law judges.

On April 6, 2010, a CPUC administrative law judge issued a proposed decision in several intrastate rate cases involving SFPP and a number of its shippers. The proposed decision includes determinations on issues, such as SFPP's entitlement to an income tax allowance and allocation of environmental expenses that are contrary both to CPUC policy and precedent and to established federal regulatory policies for pipelines. Moreover, contrary to California law, the proposed decision orders refunds relating to these issues where the underlying rates were previously deemed reasonable by the CPUC. Based on our review of these CPUC proceedings, we estimate that our maximum exposure is approximately $220 million in reparation and refund payments and if the determinations made in the proposed decision were applied prospectively in two pending cases this could result in approximately $30 million in annual rate reductions.

The proposed decision is advisory in nature and can be rejected, accepted or modified by the CPUC. SFPP filed comments on May 3, 2010 outlining the errors in law and fact within the proposed decision and on May 5, 2010, SFPP made oral arguments before the full CPUC. Further procedural steps, including motions for rehearing and writ of review to California's Court of Appeals, will be taken if warranted. We do not expect the final resolution of this matter to have an impact on our expected distributions to our limited partners for 2010.

Carbon Dioxide Litigation

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 assert claims for the underpayment of royalties on carbon dioxide produced from the McElmo Dome unit, located in southwestern Colorado. The plaintiffs assert claims for fraud/fraudulent inducement, real estate fraud, negligent misrepresentation, breach of fiduciary and agency duties, breach of contract and covenants, violation of the Colorado Unfair Practices Act, civil theft under Colorado law, conspiracy, unjust enrichment, and open account. Plaintiffs Gerald O. Bailey, Harry Ptasynski, and W.L. Gray & Co. also assert claims as private relators under the False Claims Act, claims on behalf of the State of Colorado and Montezuma County, Colorado, and claims for violation of federal and Colorado antitrust laws. The plaintiffs seek actual damages, treble damages, punitive damages, a constructive trust and accounting, and declaratory relief. The defendants filed motions for summary judgment on all claims.

On April 22, 2008, the federal district court granted defendants' motions for summary judgment and ruled that plaintiffs Bailey and Ptasynski take nothing on their claims, and that the claims of Gray be dismissed with prejudice. The court entered final judgment in favor of the defendants on April 30, 2008. The plaintiffs appealed to the United States Fifth Circuit Court of Appeals. On June 16, 2010, the Fifth Circuit Court of Appeals affirmed the trial court's summary judgment decision.

CO_2 Claims Arbitration

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

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

On October 2, 2007, the plaintiffs initiated a second arbitration (*CO_2 Committee, Inc. v. Shell CO_2 Company, Ltd., aka Kinder Morgan CO_2 Company, L.P., et al.*) against Cortez Pipeline Company, Kinder Morgan CO_2 and an ExxonMobil entity. The second arbitration asserts claims similar to those asserted in the first arbitration. On June 3, 2008, the plaintiffs filed a request with the American Arbitration Association seeking administration of the arbitration. In October 2008, the New Mexico federal district court entered an order declaring that the panel in the first arbitration should decide whether the claims in the second arbitration are barred by res judicata (an adjudicated issue that cannot be relitigated). The plaintiffs filed a motion for reconsideration of that order, which was denied by the New Mexico federal district court in January 2009. Plaintiffs appealed to the Tenth Circuit Court of Appeals. On December 21, 2009, the Tenth Circuit Court of Appeals reversed the District Court and ruled that a new arbitration panel should be convened to decide the claims and defenses asserted by the parties. A new arbitration panel has convened and a final hearing on the parties' claims and defenses is expected to occur in 2011.

MMS Notice of Noncompliance and Civil Penalty

On December 20, 2006, Kinder Morgan CO_2 received from the MMS 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." 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 stated that civil penalties will continue to accrue at the same rate until the alleged violations are corrected.

On January 3, 2007, Kinder Morgan CO_2 appealed the Notice of Noncompliance and Civil Penalty to the Office of Hearings and Appeals of the Department of the Interior. In February 2007, Kinder Morgan CO_2 filed a motion seeking to stay the accrual of civil penalties during the appeal, which was denied.

In July 2008, the parties reached a settlement of the Notice of Noncompliance and Civil Penalty, subject to final approval by the MMS and the Department of the Interior. On January 28, 2010, a representative of the MMS notified Kinder Morgan CO_2 that the Department of the Interior will not approve the settlement on its existing terms. The parties are engaged in renewed settlement discussions.

MMS Orders 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 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. 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.

In addition to the March 2007 Order to Report and Pay, the MMS issued a second Order to Report and Pay in August 2007, in which the MMS claims that Kinder Morgan CO_2 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 approximately $8.5 million for the period from April 2000 through December 2004. Kinder Morgan CO_2 filed its notice of appeal and statement of reasons in response to the second Order in September 2007, challenging the Order and appealing it to the Director of the MMS.

In July 2008, the parties reached a settlement of the March 2007 and August 2007 Orders to Report and Pay, subject to final approval by the MMS and the Department of the Interior. On January 28, 2010, a representative of the MMS notified Kinder Morgan CO_2 that the Department of the Interior will not approve the settlement on its existing terms. The parties are engaged in renewed settlement discussions.

Colorado Severance Tax Assessment

On September 16, 2009, the Colorado Department of Revenue issued three Notices of Deficiency to Kinder Morgan CO_2. The Notices of Deficiency assessed additional state severance tax against Kinder Morgan CO_2 with respect to carbon dioxide produced from the McElmo Dome unit for tax years 2005, 2006, and 2007. The total amount of tax assessed was $5.7 million, plus interest of $1.0 million, plus penalties of $1.7 million. Kinder Morgan CO_2 protested the Notices of Deficiency and paid the tax and interest under protest. Kinder Morgan CO_2 is now awaiting the Colorado Department of Revenue's response to the protest.

Montezuma County, Colorado Property Tax Assessment

In November of 2009, the County Treasurer of Montezuma County, Colorado, issued to Kinder Morgan CO_2, as operator of the McElmo Dome unit, retroactive tax bills for tax year 2008, in the amount of $2 million. Of this amount, 37.2% is attributable to Kinder Morgan CO_2's interest. The retroactive tax bills were based on the assertion that a portion of the actual value of the carbon dioxide produced from the McElmo Dome unit was omitted from the 2008 tax roll due to an alleged over statement of transportation and other expenses used to calculate the net taxable value. Kinder Morgan CO_2 paid the retroactive tax bills under protest and will file petitions for refunds of the taxes paid under protest and will vigorously contest Montezuma County's position.

Other

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

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP and UPRR are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten year period beginning January 1, 2004 (*Union Pacific Railroad Company vs. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al.,* Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In February 2007, a trial began to determine the amount payable for easements on UPRR rights-of-way. The trial is ongoing and is expected to conclude by the end of the third quarter of 2010, with a decision from the judge expected by the end of 2010.

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

Since SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations, it is difficult to quantify the effects of the outcome of these cases on SFPP. 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.

Severstal Sparrows Point Crane Collapse

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

JR Nicholls Tug Incident

On February 10, 2010, the *JR Nicholls*, a tugboat operated by one of our subsidiaries, overturned and sank in the Houston Ship Channel. Five employees were on board and four were rescued, treated and released from a local hospital. The fifth employee died in the incident. The U.S. Coast Guard shut down a section of the ship channel for approximately 60 hours. Approximately 2,200 gallons of diesel fuel was released from the tugboat. Emergency response crews deployed booms and contained the product, which is substantially cleaned up. Salvage operations were commenced and the tugboat has been recovered. A full investigation of the incident is underway.

Employee Matters

James Lugliani vs. Kinder Morgan G.P., Inc. et al. in the Superior Court of California, Orange County

James Lugliani, a former Kinder Morgan employee, filed suit in January 2010 against various Kinder Morgan affiliates. On behalf of himself and other similarly situated current and former employees, Mr. Lugliani claims that the Kinder Morgan defendants have violated the wage and hour provisions of the California Labor Code and Business & Professions Code by failing to provide meal and rest periods; failing to pay meal and rest period premiums; failing to pay all overtime wages due; failing to timely pay wages; failing to pay wages for vacation, holidays and other paid time off; and failing to keep proper payroll records. Defendants intend to vigorously defend the case.

Pipeline Integrity and Releases

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

Midcontinent Express Pipeline LLC Construction Incident

On July 15, 2009, a Midcontinent Express Pipeline LLC contractor and subcontractor were conducting a nitrogen pressure test on-facilities at a Midcontinent Express Pipeline delivery meter station that was under construction-in Smith County, Mississippi. An unexpected release of nitrogen occurred during testing, resulting in one fatality and injuries to four other employees of the contractor or subcontractor. The United States Occupational Safety and Health Administration (OSHA) completed its investigation. Neither Midcontinent Express Pipeline LLC nor we were cited for any violations by OSHA.

In July 2010, Kinder Morgan, Inc. and Midcontinent Express Pipeline LLC were named in two lawsuits arising out of the accident. One case was filed by one of the injured workers and the other case was filed by the decedent's heirs. Both cases are pending in Louisiana State District Court, Vermilion Parish. Plaintiffs allege that Kinder Morgan, Inc. and Midcontinent were negligent and grossly negligent in failing to maintain a safe worksite. Kinder Morgan, Inc. and Midcontinent have tendered the cases to the responsible insurance carriers, and they have agreed to accept the defense and indemnity. Discovery is proceeding in the cases.

Pasadena Terminal Fire

On September 23, 2008, a fire occurred in the pit 3 manifold area of our Pasadena, Texas liquids terminal facility. On January 8, 2010, a civil lawsuit was filed on behalf of the People of Texas and the TCEQ for alleged violations of the

Texas Clean Air Act. The lawsuit was filed in the 53rd Judicial District Court, Travis County, Texas and is entitled *State of Texas v. Kinder Morgan Liquids Terminals,* case no. D1GV10000017. Specifically, the TCEQ alleges that our subsidiary, Kinder Morgan Liquids Terminals LLC, had an unauthorized emission event relating to the pit 3 fire at the Pasadena terminal in September 2008. We are currently in discussions with the TCEQ legal representatives and the Texas Attorney General's office regarding resolution of this matter. We do not expect any fines or penalties related to this matter to be material.

Charlotte, North Carolina

On January 17, 2010, our subsidiary Kinder Morgan Southeast Terminal LLC's Charlotte #2 Terminal experienced an issue with a pollution control device known as the Vapor Recovery Unit, which led to a fire and release of gasoline from the facility to adjacent property and a small creek. There were no injuries. We are cooperating fully with state and federal agencies on the response and remediation.

Barstow, California

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

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, British Columbia, resulting in a release of approximately 1,400 barrels of crude oil. The release impacted the surrounding neighborhood, several homes and nearby Burrard Inlet. No injuries were reported. To address the release, we initiated a comprehensive emergency response in collaboration with, among others, the City of Burnaby, the British Columbia Ministry of Environment, the National Energy Board (Canada), and the National Transportation Safety Board (U.S.). Cleanup and environmental remediation is complete, and we have received a British Columbia Ministry of Environment Certificate of Compliance confirming complete remediation.

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

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

General

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

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date and the reserves we have established, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or distributions to limited partners. As of June 30, 2010 and December 31, 2009, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $162.8 million and $220.9 million, respectively. The reserve is primarily related to various claims from regulatory proceedings arising from our West Coast products pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. The overall change in the reserve from year-end 2009 includes both a $158.0 million increase in expense in the first quarter of 2010 associated with various rate case liability adjustments that increased our overall rate case liability, and a $206.3 million payment in the second quarter of 2010 that reduced the liability. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

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

Our subsidiary, Kinder Morgan Liquids Terminals LLC, is a defendant in a lawsuit filed in 2005 alleging claims for environmental cleanup costs at the former Los Angeles Marine Terminal in the Port of Los Angeles. The lawsuit was stayed beginning in 2009 and remains stayed through the first half of 2010. The court may lift the stay in the second half of 2010. During the stay, the parties deemed responsible by the local regulatory agency have worked with that agency concerning the scope of the required cleanup. The local regulatory agency issued specific cleanup goals in early 2010, and two of those parties, including Kinder Morgan Liquids Terminals, LLC, have appealed those cleanup goals to the state agency.

Plaintiff's Third Amended Complaint alleges that future environmental cleanup costs at the former terminal will exceed $10 million, and that the plaintiff's past damages exceed $2 million. No trial date has yet been set.

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

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

The complaint seeks any and all damages related to remediating all environmental contamination at the terminal, and, according to the New Jersey Spill Compensation and Control Act, treble damages may be available for actual dollars incorrectly spent by the successful party in the lawsuit. The parties engaged in court ordered mediation in 2008 through 2009, which did not result in settlement. The trial judge has issued a Case Management Order and the parties are actively engaged in discovery.

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

The plaintiffs seek the costs and damages that the plaintiffs allegedly have incurred or will incur as a result of the discharge of pollutants and hazardous substances at the Paulsboro, New Jersey facility. The costs and damages that the plaintiffs seek include cleanup costs and damages to natural resources. In addition, the plaintiffs seek an order compelling the defendants to perform or fund the assessment and restoration of those natural resource damages that are the result of the defendants' actions. At the time of this report, the plaintiffs have filed a report asserting that the cost of natural resource restoration is $81 million. Defendants vigorously dispute that estimate. In addition, we believe that any damages, including restoration damages, would be the responsibility of the other co-defendants under applicable law and indemnity agreements between the parties.

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. Discovery has commenced and the court has set a trial date of January 24, 2012. The City disclosed in discovery that it is seeking approximately $170 million in damages for alleged lost value/lost profit from the redevelopment of the City's property and alleged lost use of the water resources underlying the property. On January 19, 2010, the City filed a notice of intent to file an additional claim under the Resource Conservation and Recovery Act. We have been and will continue to aggressively defend this action. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board.

Kinder Morgan Port Manatee Terminal, Palmetto, Florida

On June 18, 2009, KM PMT received a Revised Warning Letter from the Florida DEP, advising us of possible regulatory and air permit violations regarding operations at our Port Manatee, Florida terminal. We previously conducted a voluntary internal audit at this facility in March 2008 and identified various environmental compliance and permitting issues primarily related to air quality compliance. We self-reported our findings from this audit in a self-disclosure letter to the Florida DEP in March 2008. Following the submittal of our self-disclosure letter, the agency conducted numerous inspections of the air pollution control devices at the terminal and issued this Revised Warning Letter. In addition, KM PMT received a subpoena from the U.S. Department of Justice for production of documents related to the service and operation of the air pollution control devices at the terminal.

In February 2010, KM PMT entered into a plea agreement with the U.S. Attorney's office for the Middle District of Florida to resolve the air permit violations at our Port Manatee terminal that occurred between 2001 and 2008. During this period of time, former local terminal management failed to disclose and address the operational condition of control equipment at the facility, as required by the Clean Air Act. To resolve the matter, KM PMT has entered into a plea agreement concerning criminal violations of the Clean Air Act and has agreed to pay a fine of $750,000 and a community service payment of $250,000 to the National Fish & Wildlife Foundation. The plea agreement was accepted by the Court on June 22, 2010. In addition, in order to resolve the matter with the Florida DEP, KM PMT has entered into a civil Consent Order with the Florida DEP under which it has agreed to implement an Environmental Compliance Plan and to pay $336,000 in civil penalties and costs. We have fully cooperated with the government's investigation, and have taken appropriate measures at the terminal, including replacing and repairing control equipment, adding new equipment, terminating certain employees, and retraining current employees on proper environmental procedures.

Kinder Morgan, EPA Section 114 Information Request

On January 8, 2010, Kinder Morgan Inc., on behalf of Natural Gas Pipeline Company of America LLC, Horizon Pipeline Company and Rockies Express Pipeline LLC, received a Clean Air Act Section 114 information request from the U.S. Environmental Protection Agency, Region V. This information request requires that the three affiliated companies provide the EPA with air permit and various other information related to their natural gas pipeline compressor station operations in Illinois, Indiana, and Ohio. The affiliated companies have responded to the request and believe the relevant natural gas compressor station operations are in substantial compliance with applicable air quality laws and regulations.

Other Environmental

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

We are currently involved in several governmental proceedings involving alleged violations of environmental and safety regulations. As we receive notices of non-compliance, we negotiate and settle these matters. We do not believe that these alleged violations will have a material adverse effect on our business.

We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs. We have established a reserve to address the costs associated with the cleanup.

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

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur, and changing circumstances could cause these matters to have a material adverse impact. As of June 30, 2010, we have accrued an environmental reserve of $76.4 million, and we believe the establishment of this environmental reserve is adequate such that the resolution of pending environmental matters will not have a material adverse impact on our business, cash flows, financial position or results of operations. In addition, as of June 30, 2010, we have recorded a receivable of $8.6 million for expected cost recoveries that have been deemed probable. As of December 31, 2009, our environmental reserve totaled $81.1 million and our estimated receivable for environmental cost recoveries totaled $4.3 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 and taking into account established reserves, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

11. Regulatory Matters

Below is a brief description of our ongoing regulatory matters, including any material developments that occurred during the six months ended June 30, 2010. This note also contains a description of any material regulatory matters initiated during the six months ended June 30, 2010 in which we are involved. In this note, we refer to the Federal Energy Regulatory Commission as the FERC.

Natural Gas Pipeline Expansion Filings

Rockies Express Pipeline LLC Meeker to Cheyenne Expansion Project

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

Sweetwater County, Wyoming; and (ii) the Wamsutter Hub eastward to the Cheyenne Hub located in Weld County, Colorado.

By FERC order issued July 16, 2009, Rockies Express Pipeline LLC was granted authorization to construct and operate this project, and it commenced construction on August 4, 2009. The expansion is fully contracted. The additional compression at the Big Hole compressor station was made available as of December 9, 2009, and the additional compression at the Arlington compressor station is expected to be operational in September 2010. The total FERC authorized cost for the proposed project is approximately $78 million; however, Rockies Express Pipeline LLC is currently projecting that the final actual cost will be approximately $25 million less.

Kinder Morgan Interstate Gas Transmission Pipeline - Huntsman 2009 Expansion Project

KMIGT has filed an application with the FERC for authorization to construct and operate certain storage facilities necessary to increase the storage capability of the existing Huntsman Storage Facility, located near Sidney, Nebraska. KMIGT also requested approval of new incremental rates for the project facilities under its currently effective Cheyenne Market Center Service Rate Schedule CMC-2. When fully constructed, the proposed facilities will create incremental firm storage capacity for up to one million dekatherms of natural gas, with an associated injection capability of approximately 6,400 dekatherms per day and an associated deliverability of approximately 10,400 dekatherms per day. As a result of an open season, KMIGT and one shipper executed a firm precedent agreement for 100% of the capacity to be created by the project facilities for a five-year term. By FERC order issued September 30, 2009, KMIGT was granted authorization to construct and operate the project, and construction of the project commenced on October 12, 2009. KMIGT received FERC approval to commence service on the expanded storage project effective February 1, 2010. Full service from the expanded facilities is expected during the third quarter of 2010.

Kinder Morgan Interstate Gas Transmission Pipeline – Franklin to Hastings Expansion Project

KMIGT has filed a prior notice request to replace, construct and operate certain mainline pipeline facilities primarily to provide up to ten million cubic feet per service to a new ethanol plant located near Aurora, Nebraska. The estimated cost of constructing the proposed facilities is $23.5 million. Provided no protests are filed, KMIGT can commence construction of this project on September 25, 2010.

Midcontinent Express Pipeline LLC – Docket Nos. CP08-6-000 and CP09-56-000

On April 10, 2009, Midcontinent Express Pipeline LLC placed Zone 1 of the Midcontinent Express natural gas pipeline system into interim service. Zone 1 extends from Bennington, Oklahoma to the interconnect with Columbia Gulf Transmission Company in Madison Parish, Louisiana. It has a design capacity of approximately 1.5 billion cubic feet per day. On August 1, 2009, construction of the pipeline was completed, and Zone 2 was placed into service. Zone 2 extends from the Columbia Gulf interconnect to the terminus of the system in Choctaw County, Alabama. It has a design capacity of approximately 1.2 billion cubic feet per day. In an order issued September 17, 2009, the FERC approved Midcontinent Express' (i) amendment to move one compressor station in Mississippi and modify the facilities at another station in Texas (both stations were among the facilities certificated in the July 2008 Order authorizing the system's original construction); and (ii) request to expand the capacity in Zone 1 by 0.3 billion cubic feet per day. On June 1, 2010 Midcontinent Express' Zone 1 expansion was placed into service, bringing the design capacity of Midcontinent Express to approximately 1.8 billion cubic feet per day in Zone 1 and to 1.2 billion cubic feet per day in Zone 2.

The Midcontinent Express Pipeline is owned by Midcontinent Express Pipeline LLC, a 50/49.9/0.1% joint venture between us, Regency Energy Partners LP, and Energy Transfer Partners, L.P., respectively. The pipeline originates near Bennington, Oklahoma and extends from southeast Oklahoma, across northeast Texas, northern Louisiana and central Mississippi, and terminates at an interconnection with the Transco Pipeline near Butler, Alabama. The approximate 500-mile natural gas pipeline system connects the Barnett Shale, Bossier Sands and other natural gas producing regions to markets in the eastern United States, and substantially all of the pipeline's capacity—including all incremental pipeline capacity that is expected to be phased in during the second and third quarters of 2010—is fully subscribed with long-term binding commitments from creditworthy shippers.

Fayetteville Express Pipeline LLC – Docket No.CP09-433-000

Construction is now underway on all phases of the previously announced Fayetteville Express Pipeline project. The Fayetteville Express Pipeline is owned by Fayetteville Express Pipeline LLC, a 50/50 joint venture between us and

Energy Transfer Partners, L.P. The Fayetteville Express Pipeline is a 187-mile, 42-inch diameter natural gas pipeline that will begin in Conway County, Arkansas, continue eastward through White County, Arkansas, and will terminate at an interconnection with Trunkline Gas Company's pipeline in Panola County, Mississippi. The pipeline will have an initial capacity of two billion cubic feet per day, and has currently secured binding commitments for at least ten years totaling 1.85 billion cubic feet per day of capacity.

On December 17, 2009, the FERC approved and issued the pipeline's certificate application authorizing pipeline construction, and initial construction on the project began in January 2010. Pending regulatory approvals, the pipeline is expected to begin interim service in the fourth quarter of 2010 and be fully in service by the end of 2010. We estimate that the total costs of this pipeline project will be below $1.2 billion (consistent with our July 21, 2010 second quarter earnings press release and below the original budget of $1.3 billion).

12. Recent Accounting Pronouncements

Accounting Standards Updates

In December 2009, the FASB issued Accounting Standards Update No. 2009-16, "Accounting for Transfers of Financial Assets" and Accounting Standards Update No. 2009-17, "Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities." ASU No. 2009-16 amended the Codification's "Transfers and Servicing" Topic to include the provisions included within the FASB's previous Statement of Financial Accounting Standards (SFAS) No. 166, "Accounting for Transfers of Financial Assets—an amendment of FASB Statement No. 140," issued June 12, 2009. ASU No. 2009-17 amended the Codification's "Consolidations" Topic to include the provisions included within the FASB's previous SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)," also issued June 12, 2009. These two Updates change the way entities must account for securitizations and special-purpose entities. ASU No. 2009-16 requires more information about transfers of financial assets, including securitization transactions, and where companies have continuing exposure to the risks related to transferred financial assets. ASU No. 2009-17 changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. For us, both Updates were effective January 1, 2010; however, the adoption of these Updates did not have any impact on our consolidated financial statements.

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, "Improving Disclosures about Fair Value Measurements." This ASU requires both the gross presentation of activity within the Level 3 fair value measurement roll forward and the details of transfers in and out of Level 1 and 2 fair value measurements. It also clarifies certain disclosure requirements on the level of disaggregation of fair value measurements and disclosures on inputs and valuation techniques. For us, this ASU was effective January 1, 2010 (except for the Level 3 roll forward which is effective for us January 1, 2011); however, because this ASU pertains to disclosure requirements only, the adoption of this ASU did not have a material impact on our consolidated financial statements.

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

General and Basis of Presentation

The following information should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes (included elsewhere in this report); and (ii) our consolidated financial statements, related notes and management's discussion and analysis of financial condition and results of operations included in our 2009 Form 10-K.

As an energy infrastructure owner and operator in multiple facets of the United States' and Canada's various energy businesses and markets, we examine a number of variables and factors on a routine basis to evaluate our current performance and our prospects for the future. Many of our operations are regulated by various U.S. and Canadian regulatory bodies. The profitability of our products pipeline transportation business is generally driven by the volume of petroleum products that we transport and the prices we receive for our services. Transportation volume levels are primarily driven by the demand for the petroleum products being shipped or stored. Demand for petroleum products tends to track in large measure demographic and economic growth, and with the exception of periods of time with very high product prices or recessionary conditions, demand tends to be relatively stable. Because of that, we seek to own refined products pipelines located in, or that transport to, stable or growing markets and population centers. The prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index.

With respect to our interstate natural gas pipelines and related storage facilities, the revenues from these assets tend to be received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed-fee reserving the right to transport natural gas, which specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Therefore, where we have long-term contracts we are not exposed to short-term changes in commodity supply or demand. However, as contracts expire, we do have exposure to the longer term trends in supply and demand for natural gas. Currently, the remaining average contract life of our natural gas transportation contracts is in excess of eight years.

Our CO_2 sales and transportation business, like our natural gas pipelines business, generally has fixed fee contracts with minimum volume requirements. In the long-term, our success in this business is driven by the demand for carbon dioxide. However, short-term changes in the demand for carbon dioxide typically do not have a significant impact on us due to the required minimum transport volumes under many of our contracts. In the oil and gas producing activities within our CO_2 business segment, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, the revenues we receive from our crude oil, natural gas liquids and carbon dioxide sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil.

The factors impacting our terminals business generally differ depending on whether the terminal is a liquid or bulk terminal, and in the case of a bulk terminal, the type of product being handled or stored. As with our products pipeline transportation business, the revenues from our bulk terminals business are generally driven by the volumes we handle and/or store, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. While we handle and store a large variety of products in our bulk terminals, the primary products are coal, petroleum coke, and steel. For the most part, we have contracts on this business that have minimum volume guarantees and are volume based above the minimums. Because these contracts are volume based above the minimums, our profitability from the bulk business can be sensitive to economic conditions. Our liquids terminals business generally is backed by longer-term contracts which require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipeline business, our liquids terminals business is less sensitive to short-term changes in supply and demand. Therefore, the extent to which changes in these variables affect our terminals business in the near term is a function of the length of the underlying service contracts, the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related factors such as hurricanes, floods and droughts may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods.

In our discussions of the operating results of individual businesses which follow, we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods. We believe that we have a history of making accretive acquisitions and economically advantageous expansions of existing businesses—since 1998, we have invested over $20 billion of capital for both strategic business acquisitions and expansions of existing assets. Our capital investments have helped us to achieve compound annual growth rates in cash distributions to our limited partners of 4.5%, 8.8%, and 7.9%, respectively, for the one-year, three-year, and five-year periods ending December 31, 2009.

Thus, the amount that we are able to increase distributions to our unitholders will, to some extent, be a function of completing successful acquisitions and expansions. We believe we will continue to have opportunities for expansion of our facilities in many markets, and we have budgeted approximately $1.5 billion for our 2010 capital expansion program, including for small acquisitions. Based on our historical record and because there is continued demand for energy infrastructure in the areas we serve, we expect to continue to have such opportunities in the future, although the level of such opportunities is difficult to predict.

Our ability to make accretive acquisitions is a function of the availability of suitable acquisition candidates at the right cost, and include factors over which we have limited or no control. Thus, we have no way to determine the number or size of accretive acquisition candidates in the future, or whether we will complete the acquisition of any such candidates.

In addition, our ability to make accretive acquisitions or expand our assets is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions. As a master limited partnership, we distribute all of our available cash and we access capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our acquisitions and expansions, often doing so during periods of notably tight financial conditions. For example, in December 2008, we raised a combined $675 million in cash from public debt and equity offerings. Although we cannot predict future changes in the overall equity and debt capital markets (in terms of tightening or loosening of credit), we believe that our stable cash flows, our investment grade credit rating, and our historical record of successfully accessing both equity and debt funding sources should allow us to continue to execute our current investment, distribution and acquisition strategies, as well as refinance maturing debt when required. For a further discussion of our liquidity, please see "—Financial Condition" below.

Critical Accounting Policies and Estimates

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

With regard to goodwill impairment testing, we review our goodwill for impairment annually, and we evaluated our goodwill for impairment on May 31, 2010. Our goodwill impairment analysis performed on that date did not result in an impairment charge, and no event indicating an impairment has occurred subsequent to that date. For more information on our goodwill impairment analysis, see Note 3 "Intangibles—Goodwill" to our consolidated financial statements included elsewhere in this report.

Further information about us and information regarding our accounting policies and estimates that we consider to be "critical" can be found in our 2009 Form 10-K. There have not been any significant changes in these policies and estimates during the six months ended June 30, 2010.

Results of Operations

Consolidated

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Earnings increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 165.2	$ 155.0	$ 10.2	7 %
Natural Gas Pipelines(c)	185.0	162.1	22.9	14 %
CO_2(d)	249.4	202.7	46.7	23 %
Terminals(e)	165.5	142.9	22.6	16 %
Kinder Morgan Canada(f)	43.9	46.7	(2.8)	(6)%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	809.0	709.4	99.6	14 %
Depreciation, depletion and amortization expense	(223.2)	(203.1)	(20.1)	(10)%
Amortization of excess cost of equity investments	(1.5)	(1.5)	-	-
General and administrative expense(g)	(93.4)	(72.6)	(20.8)	(29)%
Unallocable interest expense, net of interest income(h)	(123.8)	(101.3)	(22.5)	(22)%
Unallocable income tax expense	(2.0)	(2.3)	0.3	13 %
Net income	365.1	328.6	36.5	11 %
Net income attributable to noncontrolling interests(i)	(3.9)	(4.8)	0.9	19 %
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 361.2	$ 323.8	$ 37.4	12 %

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Earnings increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(j)	$ 171.6	$ 300.4	$ (128.8)	(43)%
Natural Gas Pipelines(k)	405.6	362.9	42.7	12%
CO_2(l)	502.6	370.1	132.5	36%
Terminals(m)	316.0	277.6	38.4	14%
Kinder Morgan Canada(n)	88.9	66.2	22.7	34%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	1,484.7	1,377.2	107.5	8%
Depreciation, depletion and amortization expense	(450.5)	(413.3)	(37.2)	(9)%
Amortization of excess cost of equity investments	(2.9)	(2.9)	-	-
General and administrative expense(o)	(194.5)	(155.1)	(39.4)	(25)%
Unallocable interest expense, net of interest income(p)	(240.1)	(205.9)	(34.2)	(17)%
Unallocable income tax expense	(4.2)	(4.6)	0.4	9%
Net income	592.5	595.4	(2.9)	-
Net income attributable to noncontrolling interests(q)	(6.0)	(7.7)	1.7	22%
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 586.5	$ 587.7	$ (1.2)	-

(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, and taxes, other than income taxes.

(b) 2010 and 2009 amounts include a decrease in income of $0.4 million and an increase in income of $1.0 million, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions. 2010 amount also includes a $15.5 million decrease in income associated with combined property environmental expenses and disposal losses related to the retirement of our Gaffey Street, California products terminal facility. 2009 amount also includes a $3.8 million increase in expense associated with environmental liability adjustments.

(c) 2010 amount includes a $0.1 million unrealized loss on derivative contracts used to hedge forecasted natural gas sales. 2009 amount includes a $2.5 million decrease in income resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas.
(d) 2010 amount includes a $7.9 million unrealized gain on derivative contracts used to hedge forecasted crude oil sales.
(e) 2010 amount includes a $6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal, and a $0.2 million increase in expense related to storm and flood clean-up and repair activities. 2009 amount includes a $0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal, and a $0.1 million increase in expense associated with environmental liability adjustments.
(f) 2009 amount includes a $3.7 million decrease in expense due to a certain non-cash accounting change related to book tax accruals made by the Express pipeline system.
(g) Includes unallocated litigation and environmental expenses. 2010 and 2009 amounts include (i) increases in expense of $1.3 million and $1.4 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses); and (ii) an increase in expense of $0.1 million and a decrease in expense of $0.9 million, respectively, related to capitalized overhead costs associated with the 2008 hurricane season. 2010 amount also includes a $1.0 million increase in expense for certain asset and business acquisition costs.
(h) 2010 and 2009 amounts include increases in imputed interest expense of $0.2 million and $0.3 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.
(i) 2010 amount includes a $0.1 million decrease in net income attributable to our noncontrolling interests, related to the effect from all of the three month 2010 items previously disclosed in these footnotes.
(j) 2010 and 2009 amounts include increases in income of $0.1 million and $0.4 million, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions. 2010 amount also includes a $158.0 million expense associated with rate case liability adjustments, and a $15.5 million decrease in income associated with combined property environmental expenses and disposal losses related to the retirement of our Gaffey Street, California products terminal facility. 2009 amount also includes a $3.8 million increase in expense associated with environmental liability adjustments. With respect to our 2010 rate case liability adjustments, following the Federal Regulatory Energy Commission's approval of a settlement agreement we reached with certain shippers, we made settlement payments totaling $206.3 million in June 2010. For more information on our rate case proceedings, see Note 10 to our consolidated financial statements included elsewhere in this report.
(k) 2010 amount includes a $0.8 million unrealized gain on derivative contracts used to hedge forecasted natural gas sales, and a $0.4 million increase in income from certain measurement period adjustments related to our October 1, 2009 natural gas treating business acquisition. 2009 amount includes a $3.8 million decrease in income resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas.
(l) 2010 amount includes a $13.3 million unrealized gain on derivative contracts used to hedge forecasted crude oil sales.
(m) 2010 amount includes a $6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal, and a $0.6 million increase in expense related to storm and flood clean-up and repair activities. 2009 amount includes a $0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal, and a $0.1 million increase in expense associated with environmental liability adjustments.
(n) 2009 amount includes a $14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to the carrying amount of Trans Mountain pipeline system's previously established deferred tax liability, and a $3.7 million decrease in expense due to a certain non-cash accounting change related to book tax accruals made by the Express pipeline system.
(o) Includes unallocated litigation and environmental expenses. 2010 and 2009 amounts include (i) increases in expense of $2.7 million and $2.8 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses); (ii) increases in expense of $2.4 million and $0.1 million, respectively, for certain asset and business acquisition costs; and (iii) decreases in expense of $0.2 million and $1.5 million, respectively, related to capitalized overhead costs associated with the 2008 hurricane season. 2010 amount also includes a $1.6 million increase in legal expense associated with certain items such as legal settlements and pipeline failures.
(p) 2010 and 2009 amounts include increases in imputed interest expense of $0.6 million and $0.8 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.
(q) 2010 and 2009 amounts include decreases of $2.4 million and $0.2 million, respectively, in net income attributable to our noncontrolling interests, related to all of the six month 2010 and 2009 items previously disclosed in these footnotes.

For the quarterly period ended June 30, 2009, net income attributable to our partners, which includes all of our limited partner unitholders and our general partner, totaled $361.2 million. This compares to net income attributable to our partners of $323.8 million for the second quarter of 2009. Total revenues for the comparable second quarter periods were $1,961.5 million in 2010 and $1,645.3 million in 2009. For the six months ended June 30, 2010 and 2009, net income attributable to our partners totaled $586.5 million and $587.7 million, respectively, on revenues of $4,091.1 million and $3,431.8 million, respectively.

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

Total segment earnings before depreciation, depletion and amortization increased $99.6 million (14%) in the second quarter of 2010, when compared to last year's second quarter. The overall increase included a slight $0.4 million decrease from the effect of the certain items described in the footnotes to the tables above (which combined to decrease total segment EBDA by $1.6 million and $1.2 million in the second quarters of 2010 and 2009, respectively). The remaining $100.0 million (14%) increase in quarterly segment earnings before depreciation, depletion and amortization included higher earnings in 2010 from all five of our business segments, with the strongest growth coming from our CO_2, Products Pipelines and Natural Gas Pipelines business segments.

For the comparable six month periods, total segment earnings before depreciation, depletion and amortization increased $107.5 million (8%) in 2010; however, the overall increase included a decrease in earnings of $134.8 million from the combined effect of the certain items described in the footnotes to the tables above (combining to decrease total segment EBDA by $152.8 million and $18.0 million in the first six months of 2010 and 2009, respectively). The remaining $242.3 million (17%) increase in total segment earnings before depreciation, depletion and amortization in the first half of 2010 versus the first half of 2009 resulted from better performance from all five of our reportable business segments, with the most significant increase attributable to our CO_2 business segment.

Products Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions, except operating statistics)			
Revenues	$ 226.3	$ 206.7	$ 433.8	$ 394.9
Operating expenses(a)	(65.0)	(60.0)	(273.9)	(109.0)
Other expense(b)	(3.9)	-	(3.9)	-
Earnings from equity investments	8.8	8.0	14.6	13.4
Interest income and Other, net-income(c)	1.3	3.5	3.9	6.3
Income tax expense	(2.3)	(3.2)	(2.9)	(5.2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 165.2	$ 155.0	$ 171.6	$ 300.4
Gasoline (MMBbl)(d)	103.4	104.2	197.2	199.8
Diesel fuel (MMBbl)	38.3	36.5	71.1	72.0
Jet fuel (MMBbl)	26.2	28.1	51.0	54.9
Total refined product volumes (MMBbl)	167.9	168.8	319.3	326.7
Natural gas liquids (MMBbl)	5.7	7.3	11.6	12.2
Total delivery volumes (MMBbl)(e)	173.6	176.1	330.9	338.9
Ethanol (MMBbl)(f)	7.6	5.5	14.8	10.6

(a) Three and six month 2010 amounts include an $11.6 million increase in property environmental expenses associated with the retirement of our Gaffey Street, California products terminal facility. Six month 2010 amount also includes a $158.0 million increase in expense associated with rate case liability adjustments. Three and six month 2009 amounts include a $3.8 million increase in expense associated with environmental liability adjustments.

(b) Three and six month 2010 amounts represent property disposal losses related to the retirement of our Gaffey Street, California products terminal facility.

(c) Three and six month 2010 amounts include a $0.4 million decrease in income and a $0.1 million increase in income, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions. Three and six month 2009 amounts include increases in income of $1.0 million and $0.4 million, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions.

(d) Volumes include ethanol pipeline volumes.

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

(f) Represents total ethanol volumes, including ethanol pipeline volumes.

For the three and six months ended June 30, 2010, the certain items described in the footnotes to the table above decreased earnings before depreciation, depletion and amortization expenses by $13.1 million and $170.0 million, respectively, when compared to the same periods of 2009. Following is information for each of the comparable three and six month periods of 2010 and 2009, related to the segment's (i) remaining $23.3 million (15%) and $41.2 million (14%) increases in earnings before depreciation, depletion and amortization; and (ii) $19.6 million (9%) and $38.9 million (10%) increases in operating revenues:

Three months ended June 30, 2010 versus Three months ended June 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	$ 13.4	20 %	$ 14.9	15 %
Southeast Terminals	7.6	56 %	6.0	30 %
Transmix operations	4.2	60 %	1.3	13 %
West Coast Terminals	3.5	22 %	2.7	12 %
Central Florida Pipeline	2.9	21 %	0.5	3 %
Cochin Pipeline	(9.5)	(68)%	(7.7)	(45)%
All others (including intrasegment eliminations)	1.2	5 %	1.9	8 %
Total Products Pipelines	$ 23.3	15 %	$ 19.6	9 %

Six months ended June 30, 2010 versus Six months ended June 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	$ 23.1	18 %	$ 25.6	14 %
Southeast Terminals	12.2	49 %	10.8	29 %
West Coast Terminals	4.7	14 %	3.8	8 %
Transmix operations	4.4	32 %	1.5	8 %
Central Florida Pipeline	4.1	16 %	1.5	5 %
Cochin Pipeline	(12.1)	(48)%	(7.9)	(29)%
All others (including intrasegment eliminations)	4.8	10 %	3.6	8 %
Total Products Pipelines	$ 41.2	14 %	$ 38.9	10 %

Overall, our Products Pipelines business segment reported strong operating results in the second quarter of 2010 as earnings before depreciation, depletion and amortization expenses increased $23.3 million (15%), when compared to the second quarter of 2009. With the exception of the Cochin pipeline system, which was impacted by lower transportation volumes in the second quarter of 2010 and by certain favorable liability adjustments recorded in the first quarter of 2009, all of the assets and operations included in our Products Pipelines business segment reported higher earnings in both the second quarter and first six months of 2010, when compared to the same periods a year ago.

For all assets combined, the segment benefitted from increases in ethanol volumes handled of 38% in the second quarter of 2010 and 40% in the first half of 2010, when compared to the same periods in 2009, respectively. Although the growing use of ethanol as part of the domestic fuel supply tends to reduce other refined products pipeline volumes, we believe the capital investments we have made for ethanol storage and blending infrastructure have enabled us to recover the decreases in revenues and cash flows resulting from lower pipeline transport volumes.

The overall increases and decreases in segment earnings before depreciation, depletion and amortization for the comparable three and six month periods of 2010 and 2009 were attributable to the following:

- increases of $13.4 million (20%) and $23.1 million (18%), respectively, from our Pacific operations—driven by (i) increased mainline delivery revenues, due to higher average tariffs partly offset by decreases in mainline delivery volumes of 1.5% and 2%, respectively; and (ii) increased terminal revenues, due to incremental ethanol handling services that were due in part to mandated increases in ethanol blending rates in California since the end of the second quarter of 2009;

- increases of $7.6 million (56%) and $12.2 million (49%), respectively, from our Southeast terminal operations—related largely to higher revenues attributable to both increased ethanol throughput and higher product inventory sales at higher prices;

- increases of $4.2 million (60%) and $4.4 million (32%), respectively, from our Transmix processing operations—due largely to incremental liquids product inventory gains of $5.1 million, recognized pursuant to a periodic physical inventory completed in the second quarter of 2010;

- increases of $3.5 million (22%) and $4.7 million (14%), respectively, from our West Coast terminal operations—driven by higher warehousing revenues at our combined Carson/Los Angeles Harbor terminal system, incremental biodiesel revenues from our liquids facilities located in Portland, Oregon, and incremental earnings contributions from the terminals' Portland, Oregon Airport pipeline, which was acquired on July 31, 2009;

- increases of $2.9 million (21%) and $4.1 million (16%), respectively, from our Central Florida Pipeline—driven by incremental product inventory gains, and for the comparable six month periods, by higher ethanol revenues and higher refined products delivery revenues;

- decreases of $9.5 million (68%) and $12.1 million (48%), respectively, from our Cochin pipeline system—attributable to a 51% decrease in total pipeline throughput volumes quarter-to-quarter, and for the comparable six month periods, attributable to both higher operating expenses and lower other non-operating income. The decreases in earnings from higher operating expenses and lower non-operating income were primarily related to favorable settlements reached in the first quarter of 2009 with the seller of the remaining approximate 50.2% interest in the Cochin pipeline system that we purchased on January 1, 2007.

Natural Gas Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
	(In millions, except operating statistics)			
Revenues(a)	$ 1,029.7	$ 860.7	$ 2,266.4	$ 1,912.4
Operating expenses(b)	(884.8)	(739.3)	(1,936.3)	(1,629.8)
Earnings from equity investments	40.1	29.4	73.9	56.0
Interest income and Other, net-income	0.1	12.6	2.3	27.3
Income tax expense	(0.1)	(1.3)	(0.7)	(3.0)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 185.0	$ 162.1	$ 405.6	$ 362.9
Natural gas transport volumes (Bcf)(c)	634.6	541.8	1,268.3	1,050.3
Natural gas sales volumes (Bcf)(d)	199.0	198.1	388.0	401.8

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(a) Six month 2010 amount includes a $0.4 million increase in revenues from certain measurement period adjustments related to our October 1, 2009 natural gas treating business acquisition.

(b) Three and six month 2010 amounts include a $0.1 million unrealized loss (from an increase in natural gas purchase costs) and a $0.8 million unrealized gain (from a decrease in natural gas purchase costs), respectively, on derivative contracts used to hedge forecasted natural gas sales. Three and six month 2009 amounts include decreases in income (from net increases in natural gas purchase costs) of $2.5 million and $3.8 million, respectively, resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas. Beginning in the second quarter of 2008, our Casper and Douglas gas processing operations discontinued hedge accounting, and the last of the related derivative contracts expired in December 2009.

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

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

For the three and six months ended June 30, 2010, the certain items described in the footnotes to the table above increased earnings before depreciation, depletion and amortization expenses by $2.4 million and $5.0 million, respectively, and increased revenues in the first six months of 2010 by $0.4 million, when compared to the same periods of 2009. Following is information for each of the comparable three and six month periods of 2010 and 2009, related to the segment's (i) remaining $20.5 million (12%) and $37.7 million (10%) increases in earnings before depreciation, depletion and amortization; and (ii) $169.0 million (20%) and remaining $353.6 million (18%) increases in operating revenues:

Three months ended June 30, 2010 versus Three months ended June 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Kinder Morgan Natural Gas Treating	$ 10.6	n/a	$ 15.3	n/a
Midcontinent Express Pipeline	6.7	957 %	-	-
Texas Intrastate Natural Gas Pipeline Group	2.9	4 %	132.9	17 %
Kinder Morgan Louisiana Pipeline	2.8	28 %	17.0	n/a
KinderHawk Field Services	1.7	n/a	-	-
Rockies Express Pipeline	1.6	7 %	-	-
Kinder Morgan Interstate Gas Transmission	(7.5)	(22)%	(4.2)	(9)%
All others	1.7	5 %	8.0	18 %
Total Natural Gas Pipelines	$ 20.5	12 %	$ 169.0	20 %

Six months ended June 30, 2010 versus Six months ended June 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Kinder Morgan Natural Gas Treating	$ 21.1	n/a	$ 30.4	n/a
Midcontinent Express Pipeline	12.1	1736 %	-	-
Kinder Morgan Louisiana Pipeline	8.1	43 %	34.0	n/a
Rockies Express Pipeline	2.2	5 %	-	-
KinderHawk Field Services	1.7	n/a	-	-
Kinder Morgan Interstate Gas Transmission	(6.9)	(11)%	(5.8)	(7)%
Texas Intrastate Natural Gas Pipeline Group	(6.1)	(4)%	274.2	16 %
All others	5.5	8 %	20.9	23 %
Intrasegment eliminations	-	-	(0.1)	(18)%
Total Natural Gas Pipelines	$ 37.7	10 %	$ 353.6	18 %

The overall increases in our Natural Gas Pipelines segment's earnings before depreciation, depletion and amortization expenses in the second quarter and first six months of 2010 versus the same periods of 2009 were driven primarily by incremental contributions from our Kinder Morgan Natural Gas Treating operations and our 50%-owned Midcontinent Express natural gas pipeline system.

We acquired our Kinder Morgan Natural Gas Treating operations on October 1, 2009, and the acquired assets contributed incremental earnings before depreciation, depletion and amortization of $10.6 million, revenues of $15.3 million and operating expenses of $4.7 million in the second quarter of 2010, and incremental earnings before depreciation, depletion and amortization of $21.1 million, revenues of $30.4 million and operating expenses of $9.3 million in the first six months of 2010.

The incremental earnings from our equity investment in the Midcontinent Express pipeline system were driven by the commencement and/or expansion of natural gas transportation service since the second quarter of 2009. The Midcontinent Express system initiated interim natural gas transportation service for its Zone 1 on April 10, 2009, achieved full Zone 1 service on May 21, 2009, and achieved full Zone 2 service on August 1, 2009. In June 2010, Midcontinent Express completed two natural gas compression projects that increased Zone 1 capacity from 1.5 to 1.8 billion cubic feet per day, and Zone 2 capacity from 1.0 to 1.2 billion cubic feet per day. The incremental capacity is fully subscribed with ten-year binding agreements.

Other period-to-period increases and decreases in segment earnings before depreciation, depletion and amortization in the comparable three and six month periods of 2010 and 2009 included the following:

- an increase of $2.9 million (4%) and a decrease of $6.1 million (4%), respectively, from our Texas intrastate natural gas pipeline group. For the comparable three month periods, the increase in earnings was driven primarily by higher margins from proprietary storage activities and natural gas processing activities, and partly offset by lower margins from natural gas sales activities. For the comparable six month periods, the overall decrease in earnings was primarily impacted by lower natural gas sales volumes and margins, lower margins from proprietary storage activities, and lower interest income due to a one-time natural gas loan to a single customer in 2009. The decrease in earnings compared to the first half of 2009 was partially offset by higher natural gas processing margins;

- increases of $2.8 million (28%) and $8.1 million (43%), respectively, from our fully-owned Kinder Morgan Louisiana natural gas pipeline system. Our Kinder Morgan Louisiana pipeline system commenced limited natural gas transportation service in April 2009, and construction was fully completed and transportation service on the system's remaining portions began in full on June 21, 2009. The overall increases in earnings included increases of $13.2 million and $26.4 million, respectively, in system operating income (revenues less operating expenses), due mainly to incremental transportation service, and decreases of $10.4 million and $18.3 million, respectively, in non-operating other income (primarily consisting of higher non-cash allowances for capital funds used during construction in the 2009 time periods);

- increases of $1.7 million and $1.7 million, respectively, due to incremental second quarter 2010 equity earnings from our 50%-owned KinderHawk Field Services LLC. We acquired our 50% ownership interest on May 21, 2010, and the joint venture's operations include natural gas gathering and treating in the Haynesville shale gas formation located in northwest Louisiana;

- increases of $1.6 million (7%) and $2.2 million (5%), respectively, from our 50%-owned Rockies Express pipeline system—largely attributable to the completion and start-up of the Rockies Express-East pipeline segment, the third and final phase of the Rockies Express system. It began initial pipeline service on June 29, 2009, and began full operations on November 12, 2009.

  Our operating results for the first half of 2010 were negatively impacted by a portion of the Rockies Express-East pipeline segment being shutdown due to a pipeline girth weld failure that occurred on November 14, 2009. Partial service was restored on January 27, 2010, with full service being restored on February 6, 2010. The shutdown cost us approximately $15 million in demand charge credits in the first quarter of 2010; and

- decreases of $7.5 million (22%) and $6.9 million (11%), respectively, from our Kinder Morgan Interstate Gas Transmission pipeline system—due largely to lower earnings from short-term natural gas balancing services (those services that offer shippers the option to store or withdraw natural gas as needed in order to manage overall gas supply), and lower volumes and prices for net fuel recoveries.

The overall changes in both segment revenues and segment operating expenses (which include natural gas costs of sales) in the comparable three and six month periods of 2010 and 2009 primarily relate to the natural gas purchase and sale activities of our Texas intrastate group, with the variances from period-to-period in both revenues and operating expenses mainly due to corresponding changes in the intrastate group's average prices and volumes for natural gas purchased and sold. The intrastate group both purchases and sells significant volumes of natural gas, which is often stored and/or transported on its pipelines, and because the group generally sells natural gas in the same price environment in which it is purchased, the increases and decreases in its gas sales revenues are largely offset by corresponding increases and decreases in its gas purchase costs. Our intrastate group accounted for 88% and 90%, respectively, of the segment's total revenues and 95% and 96%, respectively, of the segment's total operating expenses in the second quarters of 2010 and 2009, respectively. For the comparable six month periods of both years, the intrastate group accounted for 89% and 91%, respectively, of total revenues, and 95% and 97%, respectively, of total segment operating expenses.

CO_2

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions, except operating statistics)			
Revenues(a)	$ 314.6	$ 258.2	$ 636.4	$ 487.1
Operating expenses	(72.6)	(59.3)	(151.7)	(125.9)
Earnings from equity investments	6.5	5.1	13.0	10.9
Interest income and Other, net-income	1.9	-	1.9	-
Income tax benefit (expense)	(1.0)	(1.3)	3.0	(2.0)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 249.4	$ 202.7	$ 502.6	$ 370.1
Carbon dioxide delivery volumes (Bcf)(b)	191.6	188.7	382.6	401.4
SACROC oil production (gross)(MBbl/d)(c)	29.1	31.1	29.5	30.6
SACROC oil production (net)(MBbl/d)(d)	24.2	25.9	24.6	25.5
Yates oil production (gross)(MBbl/d)(c)	24.3	26.8	24.9	26.6
Yates oil production (net)(MBbl/d)(d)	10.8	11.9	11.1	11.8
Natural gas liquids sales volumes (net)(MBbl/d)(d)	10.1	9.6	9.9	9.2
Realized weighted average oil price per Bbl(e)(f)	$ 59.58	$ 49.47	$ 60.05	$ 46.71
Realized weighted average natural gas liquids price per Bbl(f)(g)	$ 48.67	$ 34.02	$ 51.78	$ 31.20

(a) Three and six month 2010 amounts include unrealized gains (from increases in revenues) of $7.9 million and $13.3 million, respectively, on derivative contracts used to hedge forecasted crude oil sales.

(b) Includes Cortez, Central Basin, Canyon Reef Carriers, Centerline and Pecos pipeline volumes.

(c) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit and an approximately 50% working interest in the Yates unit.

(d) Net to us, after royalties and outside working interests.

(e) Includes all of our crude oil production properties.

(f) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.

(g) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our CO_2 segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) and crude oil, and the production and marketing of natural gas and natural gas liquids. We refer to the segment's two primary businesses as its Sales and Transportation Activities and its Oil and Gas Producing Activities.

For the three and six months ended June 30, 2010, the unrealized gains on derivative contracts used to hedge forecasted crude oil sales described in footnote (a) to the table above increased both earnings before depreciation, depletion and amortization expenses and revenues by $7.9 million and $13.3 million, respectively, when compared to the same periods of 2009. For each of the segment's two primary businesses, following is information for each of the comparable three and six month periods of 2010 and 2009, related to the segment's (i) remaining $38.8 million (19%) and $119.2 million (32%) increases in earnings before depreciation, depletion and amortization; and (ii) remaining $48.5 million (19%) and $136.0 million (28%) increases in operating revenues:

Three months ended June 30, 2010 versus Three months ended June 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 21.9	14 %	$ 37.5	18 %
Sales and Transportation Activities	16.9	35 %	15.8	27 %
Intrasegment eliminations	-	-	(4.8)	(52)%
Total CO_2	$ 38.8	19 %	$ 48.5	19 %

Six months ended June 30, 2010 versus Six months ended June 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 95.3	37 %	$ 119.4	31 %
Sales and Transportation Activities	23.9	22 %	19.6	15 %
Intrasegment eliminations	-	-	(3.0)	(13)%
Total CO_2	$ 119.2	32 %	$ 136.0	28 %

The overall period-to-period increases in earnings before depreciation, depletion and amortization expenses from oil and gas producing activities, which include the operations associated with the segment's ownership interests in oil-producing fields and natural gas processing plants, were mainly due to the following:

- increases of $34.8 million (17%) and $113.8 million (31%), respectively, in combined crude oil and natural gas plant products sales revenues, due largely to increases of 20% and 29%, respectively, in our realized weighted average price per barrel of crude oil, and increases of 43% and 66%, respectively, in our realized weighted average price per barrel of natural gas liquids. We also benefitted from period-to-period increases in natural gas liquids sales volumes. However, increases in crude oil revenues due to higher prices were somewhat offset by decreases in crude oil production volumes of 7% in the second quarter of 2010 and 4% in the first six months of 2010, when compared to the same periods a year ago;

- increases of $2.7 million (44%) and $5.6 million (47%), respectively, in other combined revenues, including natural gas sales, net profit interests and other service revenues. The quarterly increase was driven by higher natural gas sales revenues in 2010, and for the comparable six month periods, the increase was driven by higher net profit interests revenues in 2010 (from our interest in the Snyder, Texas natural gas processing plant); and

- decreases of $17.6 million (32%) and $26.2 million (21%), respectively, due to higher combined operating expenses. The overall increases in expenses were driven by (i) increases of $11.5 million (177%) and $12.3 million (361%), respectively, in tax expenses, other than income tax expenses, due primarily to a $15.4 million reduction in severance tax expense in the second quarter of 2009 due to prior year overpayments; and (ii) increases of $6.3 million (14%) and $9.6 million (11%), respectively, in operating and maintenance expenses, due largely to increased natural gas processing volumes.

The overall period-to-period increases in earnings from sales and transportation activities were mainly due to the following:

- increases of $15.5 million (41%) and $20.8 million (25%), respectively, in carbon dioxide sales revenues. The period-to-period increases in sales revenues were primarily price related, and partly volume related. The segment's average price received for all carbon dioxide sales in the second quarter and first six months of 2010 increased 36% and 23%, respectively, and overall carbon dioxide sales volumes increased 4% and 1%, respectively, when compared to the same prior year periods; and

- increases of $1.4 million (27%) and $2.1 million (19%), respectively, due to higher equity earnings from our 50% ownership interest in the Cortez Pipeline Company. The increase reflects higher net income earned by Cortez in 2010, chiefly due to lower depreciation expense resulting from a lower depreciable pipeline property base relative to 2009.

Terminals

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In millions, except operating statistics)			
Revenues	$ 320.5	$ 264.0	$ 624.6	$ 531.9
Operating expenses(a)	(160.7)	(123.9)	(316.6)	(257.5)
Other income(b)	9.2	2.7	10.5	3.6
Earnings from equity investments	0.4	-	0.6	0.1
Interest income and Other, net-income (expense)	(0.5)	1.2	0.4	1.1
Income tax expense	(3.4)	(1.1)	(3.5)	(1.6)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 165.5	$ 142.9	$ 316.0	$ 277.6
Bulk transload tonnage (MMtons)(c)	25.2	19.8	46.6	39.1
Ethanol (MMBbl)	14.6	8.0	30.0	16.6
Liquids leaseable capacity (MMBbl)	58.2	55.1	58.2	55.1
Liquids utilization %	95.8%	96.9%	95.8%	96.9%

(a) Three and six month 2010 amounts include increases in expense of $0.2 million and $0.6 million, respectively, related to storm and flood clean-up and repair activities. Three and six month 2009 amounts include a $0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal, and a $0.1 million increase in expense associated with environmental liability adjustments.

(b) Three and six month 2010 amounts include a $6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal.

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

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

The segment's operating results in the first half of 2010 include incremental contributions from strategic terminal acquisitions. Since the end of the second quarter of 2009, we have invested $212.8 million in cash and $81.7 million in common units to acquire various terminal assets and operations, and combined, our acquired terminal operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $8.3 million, revenues of $16.9 million, and operating expenses of $8.6 million in the second quarter of 2010.

For the first six months of 2010, acquired assets contributed incremental earnings before depreciation, depletion and amortization of $14.8 million, revenues of $31.7 million, and operating expenses of $16.9 million. All of the incremental amounts listed above represent the earnings, revenues and expenses from acquired terminals' operations during the additional months in 2010, and do not include increases or decreases during the same months we owned the assets in 2009. For more information on the terminal assets and operations we acquired in the first six months of 2010, see Note 2 "Acquisitions, Joint Ventures, and Divestitures—Acquisitions" to our consolidated financial statements included elsewhere in this report.

For all other terminal operations (those owned during identical periods in both 2010 and 2009), the certain items described in the footnotes to the table accounted for increases in earnings before depreciation, depletion and amortization of $6.1 million for the second quarter of 2010 and $5.7 million for the first six months of 2010, when compared to the same two periods last year. Following is information for these terminal operations, for each of the comparable three and six month periods and by terminal operating region, related to (i) the remaining $8.2 million (6%) and $17.9 million (6%) increases in earnings before depreciation, depletion and amortization; and (ii) the $39.6 million (15%) and $61.0 million (11%) increases in operating revenues:

Three months ended June 30, 2010 versus Three months ended June 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Mid-River	$ 3.3	90 %	$ 10.1	87 %
Southeast	2.9	29 %	5.1	23 %
Ohio Valley	2.9	68 %	4.9	36 %
Gulf Coast	2.4	7 %	3.5	8 %
West	2.3	19 %	8.6	44 %
Texas Petcoke	2.0	12 %	4.4	13 %
Lower River (Louisiana)	(3.1)	(22) %	2.7	12 %
All others (including intrasegment eliminations and unallocated income tax expenses)	(4.5)	(10) %	0.3	-
Total Terminals	$ 8.2	6 %	$ 39.6	15 %

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Six months ended June 30, 2010 versus Six months ended June 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
West	$ 10.5	52 %	$ 21.7	58 %
Mid-River	5.7	76 %	15.6	63 %
Southeast	4.5	23 %	8.6	20 %
Gulf Coast	3.9	6 %	6.4	7 %
Ohio Valley	3.0	39 %	6.5	25 %
Texas Petcoke	(3.4)	(10) %	(0.3)	-
Lower River (Louisiana)	(3.0)	(12) %	3.1	7 %
All others (including intrasegment eliminations and unallocated income tax expenses)	(3.3)	(4) %	(0.6)	-
Total Terminals	$ 17.9	6 %	$ 61.0	11 %

The period-to-period increases in earnings from our Mid-River, Ohio Valley, and Southeast terminals, which are located in the Central and Southeast regions of the U.S., were primarily driven by incremental business activity (including increased import/export activity) involving the handling and storage of steel and alloy products, driven by rebounding steel consumption consistent with the ongoing economic recovery. Although our steel handling business remains below pre-recession levels, the increased business activity in the first half of 2010 reflects a favorable change from the economic downturn that resulted in drops in tonnage, revenues, and earnings at our various owned or operated terminal facilities during 2009. For our Terminals segment combined, bulk traffic tonnage increased by 5.4 million tons (27%) in the second quarter of 2010 and by 7.5 million tons (19%) in the first six months of 2010, when compared with the same prior year periods.

The overall increases in earnings from our West region terminals were driven by (i) higher period-to-period earnings from our Vancouver Wharves bulk marine terminal, located at the Port of Vancouver, British Columbia, due to both higher revenues from an increase in agricultural product volumes, and favorable currency impacts from a strengthening of the Canadian dollar since the end of the second quarter last year; and (ii) incremental business (including increased agricultural exports) and higher rate tonnage in the second quarter and first six months of 2010 from our Longview and Vancouver, Washington terminal facilities.

The increases in earnings from our Gulf Coast terminals reflect favorable results from our Pasadena and Galena Park, Texas liquids facilities located along the Houston Ship Channel. The earnings increases were driven by higher liquids warehousing revenues, mainly due to new and incremental customer agreements (at higher rates), and to the completion of various terminal expansion projects that increased liquids tank capacity since the end of the second quarter of 2009. For all liquids terminals combined, expansion projects completed since the end of the second quarter last year increased our liquids terminals' leasable capacity to 58.2 million barrels, up 5.6% from a capacity of 55.1 million barrels at June 30, 2009.

Earnings from our Texas Petcoke operations, which provide handling and trucking services for petroleum coke, sulfur and other products in and around Southeast Texas, increased in the second quarter of 2010 and decreased in the first six months of 2010, versus the comparable periods of 2009. The quarterly increase in earnings was driven by an overall 12% increase in petroleum coke tonnage and by incremental stevedoring services in the second quarter of 2010. The decrease in earnings across both six month periods was primarily due to lower average rates per ton of petroleum coke moved in the first half of 2010. The lower rates resulted largely from a decrease in Producer Price Index escalators in certain key customer contracts, when compared to the same period last year.

The period-to-period decreases in earnings from our remaining terminal operations were primarily due to (i) lower second quarter 2010 earnings from our International Marine Terminals facility (included in our Lower River (Louisiana) region); and (ii) higher segment income tax expenses in the first half of 2010 (from income tax expenses not allocated to regions but instead included in the "All others" line in the two tables above). The decreases at IMT were mainly due to a $3.2 million property casualty gain recognized in the second quarter of 2009 on a vessel dock that was damaged in March 2008. The increases in income tax expenses were due to higher taxable income during 2010 in many of our tax paying terminal subsidiaries.

Kinder Morgan Canada

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
	(In millions, except operating statistics)			
Revenues	$ 70.6	$ 56.0	$ 130.4	$ 106.0
Operating expenses	(23.7)	(18.1)	(43.2)	(33.3)
Earnings from equity investments	(0.6)	(0.6)	(0.2)	(0.3)
Interest income and Other, net-income	1.8	8.2	7.6	8.9
Income tax benefit (expense)(a)	(4.2)	1.2	(5.7)	(15.1)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 43.9	$ 46.7	$ 88.9	$ 66.2
Transport volumes (MMBbl)(b)	28.3	24.3	52.1	46.9

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

(b) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of our Trans Mountain and Jet Fuel pipeline systems, and our one-third equity ownership interest in the Express pipeline system. For the three and six months ended June 30, 2010, the certain items described in footnote (a) to the table above decreased earnings before depreciation, depletion and amortization expenses by $3.7 million and increased earnings before depreciation, depletion and amortization expenses by $11.2 million, respectively, when compared to the same periods of 2009.

Following is information for each of the comparable three and six month periods of 2010 and 2009, related to the segment's (i) remaining $0.9 million (2%) and $11.5 million (15%) increases in earnings before depreciation, depletion and amortization; and (ii) $14.6 million (26%) and $24.4 million (23%) increases in operating revenues:

Three months ended June 30, 2010 versus Three months ended June 30, 2009

	EBDA increase/(decrease)		Revenues Increase/(decrease)	
	(In millions, except percentages)			
Express Pipeline	$ 1.2	89 %	$ -	-
Trans Mountain and Jet Fuel Pipelines	(0.3)	(1)%	14.6	26 %
Total Kinder Morgan Canada	$ 0.9	2 %	$ 14.6	26 %

Six months ended June 30, 2010 versus Six months ended June 30, 2009

	EBDA Increase/(decrease)		Revenues Increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain and Jet Fuel Pipelines	$ 10.2	14 %	$ 24.4	23 %
Express Pipeline	1.3	27 %	-	-
Total Kinder Morgan Canada	$ 11.5	15 %	$ 24.4	23 %

The segment's overall increase in earnings before depreciation, depletion and amortization expenses for the comparable three month periods was driven by higher earnings in 2010 from our investment in the Express pipeline system. The $1.2 million (89%) increase in Express' earnings was driven by lower income tax expenses, higher income from gains and losses from foreign currency transactions, and higher interest income, relative to the second quarter of 2009.

For the comparable six month periods of 2010 and 2009, the segment's overall $11.5 million (15%) increase in earnings before depreciation, depletion and amortization was driven by higher operating income (revenues less operating expenses) from our Trans Mountain and Jet Fuel pipeline systems. The increase in operating income was driven by strong ship traffic at Port Metro Vancouver and by a favorable currency impact due to a strengthening of the Canadian dollar since the end of the second quarter last year.

Other

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
General and administrative expenses(a)	$ 93.4	$ 72.6	$ 194.5	$ 155.1
Unallocable interest expense, net of interest income(b)	$ 123.8	$ 101.3	$ 240.1	$ 205.9
Unallocable income tax expense	$ 2.0	$ 2.3	$ 4.2	$ 4.6
Net income attributable to noncontrolling interests(c)	$ 3.9	$ 4.8	$ 6.0	$ 7.7

(a) Includes such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services. Three and six month 2010 amounts include (i) increases in expense of $1.3 million and $2.7 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses); (ii) increases in expense of $1.0 million and $2.4 million, respectively, for certain asset and business acquisition costs; and (iii) an increase in expense of $0.1 million and a decrease in expense of $0.2 million, respectively, related to capitalized overhead costs associated with the 2008 hurricane season. Six month 2010 amount also includes an increase in legal expense of $1.6 million associated with certain items such as legal settlements and pipeline failures. Three and six month 2009 amounts include (i) increases in expense of $1.4 million and $2.8 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses); and (ii) decreases in expense of $0.9 million and $1.5 million, respectively, from capitalized overhead costs associated with the 2008 hurricane season. Six month 2009 amount also includes an increase in expense of $0.1 million for certain asset and business acquisition costs that were capitalized under prior accounting standards.

(b) Three and six month 2010 amounts include increases in imputed interest expense of $0.2 million and $0.6 million, respectively, and three and six month 2009 amounts include increases in imputed interest expense of $0.3 million and $0.8 million, respectively, all related to our January 1, 2007 Cochin Pipeline acquisition.

(c) Three and six month 2010 amounts include decreases of $0.1 million and $2.4 million, respectively, in net income attributable to our noncontrolling interests, and the six month 2009 amount includes a decrease of $0.2 million in net income attributable to our noncontrolling interests, all related to the combined effect of the three and six month 2010 and 2009 items previously disclosed in the footnotes to the tables included above in "—Results of Operations."

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services.

For the three and six months ended June 30, 2010, the certain items described in footnote (a) to the table above increased our general and administrative expenses by $1.9 million and $5.1 million, respectively, when compared with the same periods last year. The remaining $18.9 million (26%) and $34.3 million (22%) period-to-period increases in expenses included increases of (i) $5.9 million and $12.5 million, respectively, from higher employee benefit and payroll tax expenses; (ii) $5.5 million and $8.0 million, respectively, from higher overall corporate insurance expenses; (iii) $3.2 million and $6.2 million, respectively, from lower capitalization of overhead expenses (other than benefits and payroll taxes); and (iv) $2.1 million and $4.5 million, respectively, from higher unallocated legal expenses.

The increases in benefit and payroll tax expenses were mainly due to cost inflation increases on work-based health and insurance benefits, higher wage rates and a larger year-over-year labor force. The increases in insurance expenses were largely due to higher expense accruals in 2010 for year-over-year increases in commercial property and liability insurance costs, and for the comparable six month periods, to incremental premium taxes. The drops in capitalized expenses were due to lower capital spending in the first half of 2010, relative to the first six months of 2009.

We report our interest expense as "net," meaning that we have subtracted unallocated interest income and capitalized interest from our total interest expense to arrive at one interest amount, and after taking into effect the certain items described in footnote (b) to the table above, our unallocable interest expense increased $22.6 million (22%) in the second quarter of 2010 and $34.4 million (17%) in the first half of 2010, when compared to the same 2009 periods. The increases in interest expense were attributable to higher average debt balances in 2010. Average borrowings for the three and six month periods ended June 30, 2010 increased 26% and 25%, respectively, when compared to the same periods a year ago, largely due to the capital expenditures, business acquisitions, and joint venture contributions we have made since the end of the second quarter of 2009.

The overall period-to-period increases in interest expense in the first half of 2010 were partially offset by decreases in expense due to lower effective interest rates relative to the first half of 2009. Due to a general drop in variable interest rates since the end of the second quarter of 2009, the weighted average interest rate on all of our borrowings decreased 5% in the second quarter of 2010 and 10% in the first six months of 2010, when compared to the same prior year periods. We use interest rate swap agreements to transform a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt, and in periods of falling interest rates, these swaps result in period-to-period decreases in our interest expense.

As of June 30, 2010, approximately 53% of our $11,850.8 million consolidated debt balance (excluding the value of interest rate swap agreements) was subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 6 "Risk Management—Interest Rate Risk Management" to our consolidated financial statements included elsewhere in this report.

Financial Condition

General

As of June 30, 2010, we believe our balance sheet and liquidity positions remained strong. Cash and cash equivalents on hand at quarter end was $143.1 million, and we generated $932.2 million in cash from operations in the first half of 2010, consistent with the $936.8 million we generated in the first half of 2009. We continue to have access to additional sources of liquidity through (i) our committed $2.0 billion senior unsecured revolving bank credit facility, which replaced our previous $1.79 billion five-year unsecured revolving bank credit facility (discussed both in Note 4 "Debt—Credit Facility" to our consolidated financial statements included elsewhere in this report and below in "—Short-term Liquidity"); and (ii) the issuance, in the second quarter of 2010, of an additional $1 billion in senior notes (receiving proceeds, after underwriting discounts and commission, of $993.1 million) and an additional 6,743,042 common units from equity sales (receiving proceeds, after underwriting commissions and expenses, of $433.2 million).

Our primary cash requirements, in addition to normal operating expenses, are for debt service, sustaining capital expenditures (defined as capital expenditures which do not increase the capacity of an asset), expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholder and general partner.

In general, we expect to fund:

- cash distributions and sustaining capital expenditures with existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits with retained cash (which may result from including i-units in the determination of cash distributions per unit but paying quarterly distributions on i-units in additional i-units rather than cash), additional borrowings, and the issuance of additional common units or the proceeds from purchases of additional i-units by KMR;
- interest payments with cash flows from operating activities; and
- debt principal payments with additional borrowings, as such debt principal payments become due, or by the issuance of additional common units or the proceeds from purchases of additional i-units by KMR.

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

Credit Ratings and Capital Market Liquidity

As part of our financial strategy, we try to maintain an investment-grade credit rating, which involves, among other things, the issuance of additional limited partner units in connection with our acquisitions and expansion activities in order to maintain acceptable financial ratios. Currently, our long-term corporate debt credit rating is BBB (stable), Baa2 (negative) and BBB (stable), at Standard & Poor's Ratings Services, Moody's Investors Service, Inc. and Fitch Inc., respectively.

On February 25, 2010, Standard & Poor's revised its outlook on our long-term credit rating to stable from negative, affirmed our long-term credit rating at BBB, and raised our short-term credit rating to A-2 from A-3. The rating agency's revisions reflected its expectations that our financial profile will improve due to lower guaranteed debt obligations and higher expected cash flows associated with the completion and start-up of the Rockies Express, Midcontinent Express and Kinder Morgan Louisiana natural gas pipeline systems. As a result of this upward revision to our short-term rating, we currently have some access to the commercial paper market that was not available prior to this rating change. Therefore, we expect that our short-term liquidity needs will be met through borrowings made under our bank credit facility and our commercial paper program. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the energy and terminals industries and other financial and business factors, some of which are beyond our control.

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

Short-term Liquidity

Our principal sources of short-term liquidity are our (i) $2.0 billion senior unsecured revolving bank credit facility that matures June 23, 2013; and (ii) cash from operations (discussed below in "—Operating Activities"). Borrowings under our bank credit facility can be used for general partnership purposes and as a backup for our commercial paper program. The facility can be amended to allow for borrowings of up to $2.3 billion.

Our outstanding short-term debt as of June 30, 2010 was $1,571.1 million, primarily consisting of (i) $700.0 million in principal amount of 6.75% senior notes that mature March 15, 2011; (ii) $501.4 million of commercial paper borrowings; (iii) $250.0 million in principal amount of 7.50% senior notes that mature November 1, 2010; and (iv) $75.0 million in outstanding borrowings under our bank credit facility. We intend to refinance our current short-term debt and any additional short-term debt incurred during the remainder of the year through a combination of long-term debt, equity, and either the issuance of additional commercial paper or additional bank credit facility borrowings to replace maturing commercial paper and bank credit facility borrowings and current maturities of long-term debt.

We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our bank credit facility. After reduction for (i) our letters of credit; and (ii) combined borrowings under our credit facility and our commercial paper program, the remaining available borrowing capacity under our bank credit facility was $1,201.4 million as of June 30, 2010. This remaining borrowing capacity allows us to manage our day-to-day cash requirements and any anticipated obligations, and currently, we believe our liquidity to be adequate.

We had working capital deficits (current assets minus current liabilities) of $1,646.6 million as of June 30, 2010 and $772.9 million as of December 31, 2009. The unfavorable change from year-end 2009 was primarily due to our higher short-term debt obligations as of June 30, 2010 (discussed above). Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts and changes in cash and cash equivalent balances as a result of debt or equity issuances (discussed below in "—Long-term Financing"). As a result, our working capital balance could return to a surplus in future periods. A working capital deficit is not unusual for us or for other companies similar in size and scope to us, and we believe that our working capital deficit does not indicate a lack of liquidity as we continue to maintain adequate current assets to satisfy current liabilities and maturing obligations when they come due.

Long-term Financing

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements (other than distributions of cash from operations 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.

Our equity offerings consist of the issuance of additional common units or the issuance of additional i-units to KMR (which KMR purchases with the proceeds from the sale of additional KMR shares). As a publicly traded limited partnership, our common units are attractive primarily to individual investors, although such investors represent a small segment of the total equity capital market. We believe that some institutional investors prefer shares of KMR over our common units due to tax and other regulatory considerations, and we are able to access this segment of the capital market through KMR's purchases of i-units issued by us with the proceeds from the sale of KMR shares to institutional investors.

From time to time we issue long-term debt securities, often referred to as our senior notes. All of our senior notes issued to date, other than those issued by our subsidiaries and operating partnerships, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums.

We are subject, however, to conditions in the equity and debt markets for our limited partner units and long-term senior 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 senior notes in the future. If we were unable or unwilling to issue additional limited partner units, we would be required to either restrict expansion capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. See "—Credit Ratings and Capital Market Liquidity" above for a discussion of our credit ratings.

As of June 30, 2010 and December 31, 2009, the net carrying value of the various series of our senior notes was $11,125.4 million and $10,125.3 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $149.0 million and $167.1 million, respectively. To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives.

For more information on our 2010 debt related transactions, including our issuances of senior notes, see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report, and for additional information regarding our debt securities, see Note 8 "Debt" to our consolidated financial statements included in our 2009 Form 10-K. For information on our 2010 equity issuances, see Note 5 "Partners' Capital" to our consolidated financial statements included elsewhere in this report.

Capital Structure

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

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

Capital Expenditures

Including both sustaining and discretionary spending, our capital expenditures were $451.1 million in the first six months of 2010, versus $796.6 million in the same year-ago period. Our sustaining capital expenditures—defined as capital expenditures which do not increase the capacity of an asset—totaled $80.4 million in the first six months of 2010, compared to $70.7 million for the first six months of 2009. These sustaining expenditure amounts include our proportionate share of both Rockies Express Pipeline LLC's, Midcontinent Express Pipeline LLC's, and KinderHawk Field Services LLC's sustaining capital expenditures—approximately $0.1 million in the first six months of both 2010 and 2009. Additionally, our forecasted expenditures for the remaining six months of 2010 for sustaining capital expenditures are approximately $116.1 million, including approximately $0.1 million for our proportionate shares of Rockies Express, Midcontinent Express, and KinderHawk Field Services.

Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from their own operations, Rockies Express Pipeline LLC and Midcontinent Express Pipeline LLC can each fund their own cash requirements for expansion capital expenditures through borrowings under their own credit facilities, issuing their own long-term notes, or with proceeds from contributions received from their equity owners. KinderHawk Field Services LLC can fund its own cash requirements for expansion capital expenditures with cash generated from its own operations, through borrowings under its own credit facility (it has a $200 million three-year, nonrecourse (to its owners) revolving bank credit facility), or with proceeds from contributions received from its equity owners.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. The discretionary capital expenditures reflected in our consolidated statement of cash flows for the first six months of 2010 and 2009 were $370.8 million and $726.0 million, respectively. The period-to-period decrease in discretionary capital expenditures was mainly due to higher capital expenditures made during the first half of 2009 on both our major natural gas pipeline projects and on expansions and improvements within our Terminals and CO_2 business segments. Generally, we fund our discretionary capital expenditures and our investment contributions through borrowings under our bank credit facility or our commercial paper program. To the extent this source of funding is not sufficient, we generally fund additional amounts through the issuance of long-term notes or common units for cash.

Capital Requirements for Recent Transactions

In the first six months of 2010, our cash outlays for the acquisitions of assets and equity investments totaled $1,147.8 million. With the exception of our acquisition of terminal assets from US Development Group LLC, which was partially acquired by the issuance of additional common units, we utilized our commercial paper program to fund these acquisitions and then reduced our short-term borrowings with the proceeds from our May and June 2010 issuances of common units, and our May 2010 issuance of long-term senior notes. In addition, in July 2010, we received net proceeds of $75.0 million from the offering of 1,167,315 of our common units in a privately negotiated transaction.

Operating Activities

Net cash provided by operating activities was $932.2 million for the six months ended June 30, 2010, essentially flat when compared with the $936.8 million in cash provided by operating activities in the comparable period of 2009. The period-to-period decrease of $4.6 million in cash provided by operating activities primarily consisted of:

- a $190.8 million decrease in cash attributable to higher payments made in 2010 for transportation rate settlements, refunds and reparations made pursuant to certain legal settlements reached with various shippers on our Pacific operations' refined products pipelines. In May 2010, we paid $206.3 million to eleven of twelve shippers regarding the settlement of various transportation rate challenges filed with the Federal Energy Regulatory Commission (FERC) dating back as early as 1992. In May 2009, we made refund and settlement payments totaling $15.5 million to various shippers in connection with certain East Line rate settlement agreements;

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

- a $187.2 million increase in cash from overall higher partnership income—after adjusting for the following five non-cash items: (i) depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments); (ii) undistributed earnings from equity investees; (iii) income from the allowance for equity funds used during construction; (iv) income from the sale or casualty of property, plant and equipment and other net assets; and (v) a $158.0 million expense related to rate case liability adjustments recorded in the first quarter of 2010. The period-to-period increase in partnership income from our five reportable business segments in the first six months of 2010 versus the first six months of 2009 is discussed above in "—Results of Operations" (including all of the certain items disclosed in the associated table footnotes); and

- a $137.8 million increase in cash inflows relative to net changes in working capital items, primarily driven by (i) a $101.6 million increase in net cash inflows from the collection and payment of trade and related party receivables and payables (including collections and payments on natural gas transportation and exchange imbalance receivables and payables); and (ii) a $42.8 million increase in cash from higher payments in the first half of 2009 for natural gas storage on our Kinder Morgan Texas Pipeline system.

Investing Activities

Net cash used in investing activities was $1,667.9 million for the six-month period ended June 30, 2010, compared to $1,537.9 million in the comparable 2009 period. The overall $130.0 million (8%) period-to-period decrease in cash from our investing activities in the first six months of 2010 compared to the first six months of 2009 was attributable to:

- a combined $1,129.3 million decrease in cash due to higher acquisitions of assets and investments. In the first six months of 2010, our cash outlays for strategic business acquisitions totaled $1,147.8 million, primarily consisting of the following (i) $921.4 million for a 50% equity ownership interest in Petrohawk Energy Corporation's natural gas gathering and treating business; (ii) $115.7 million for three unit train ethanol handling terminals acquired from US Development Group LLC in January 2010; and (iii) $97.0 million for terminal assets and investments acquired from Slay Industries in March 2010. Each of these 2010 acquisitions is discussed further in Note 2 "Acquisitions, Joint Ventures, and Divestitures" to our consolidated financial statements included elsewhere in this report. In the first half of 2009, our cash payments for acquired assets totaled $18.5 million, including $18.0 million for the acquisition of certain marine vessels from Megafleet Towing Co., Inc.;

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

- a $621.9 million increase in cash due to lower contributions to equity investees in the first half of 2010. The increase in cash was driven by a $628.2 million decrease in combined contributions made to Rockies Express Pipeline LLC, Midcontinent Express Pipeline LLC, and Fayetteville Express Pipeline LLC in the first half of 2010, largely due to incremental contributions made in the first half of 2009 to partially fund our respective share of Rockies Express, Midcontinent Express, and Fayetteville Express pipeline system construction and/or pre-construction costs;

- a $345.5 million increase in cash due to lower capital expenditures in the first six months of 2010—largely due to the higher investment undertaken in the first half of 2009 to construct our Kinder Morgan Louisiana Pipeline and to expand and improve our Terminals business segment;

- a $93.3 million increase in cash due to higher capital distributions (distributions in excess of cumulative earnings) received in the first half of 2010, primarily related to distributions received from our equity investments in Rockies Express Pipeline LLC, Midcontinent Express Pipeline LLC, and Fayetteville Express Pipeline LLC. Current accounting practice requires us to classify and report cumulative cash distributions in excess of cumulative equity earnings as a return of capital; however, this change in classification does not impact our cash available for distribution; and

- a $27.2 million increase in cash due to higher net proceeds received in the first half of 2010 from property sales and casualty insurance settlements, mainly related to insurance indemnifications received for (i) assets damaged during the 2008 hurricane season; (ii) property damaged at our Pasadena, Texas liquids terminal facility from a fire in September 2008; and (iii) a marine vessel dock damaged at our International Marine Terminals facility in March 2008.

Financing Activities

Net cash provided by financing activities totaled $733.0 million for the first six months of 2010. For the first six months a year ago, our financing activities provided net cash of $638.6 million. The $94.4 million (15%) overall increase in cash from the comparable 2009 period was mainly due to:

- a $404.3 million increase in cash 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 overall financing activities in the first half of 2010 was primarily due to (i) a $501.4 million increase in cash due to net commercial paper borrowings in the first half of 2010 (we had no commercial paper borrowings during the first six months of 2009); (ii) a $250.0 million increase in cash due to the February 1, 2009 retirement of the principal amount of our 6.30% senior notes that matured on that date; and (iii) a $325.0 million decrease in cash from lower net borrowings under our bank credit facility in the first half of 2010.

  The incremental cash inflows of $993.1 million from our issuances of additional senior notes in the first half of 2010 (discussed in Note 4 "Debt—Senior Notes" to our consolidated financial statements included elsewhere in this report) were offset by the $993.3 million decrease in cash for proceeds we received, after underwriting discounts and commissions, from the issuance of an aggregate $1 billion in principal amount of senior notes in two separate series in May 2009;

- a $29.7 million increase in cash from net changes in cash book overdrafts—resulting from timing differences on checks issued but not yet presented for payment;

- a $236.3 million decrease in cash from lower partnership equity issuances. The decrease relates to the $433.2 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first half of 2010 (discussed in Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report), versus the $669.5 million we received from the sales of additional common units in the first half of 2009.

  The $669.5 million in proceeds received in 2009 included $124.6 million from the issuance of 2,556,747 common units pursuant to our equity distribution agreement with UBS Securities LLC, and a combined $544.9 million from two separate underwritten public offerings of our common units in March and June of 2009. We used the proceeds from our 2009 equity issuances to reduce the borrowings under our bank credit facility, and we used the proceeds from our 2010 public offering to reduce the borrowings under both our commercial paper program and our bank credit facility; and

- a $102.1 million decrease in cash due to higher partnership distributions in the first six months of 2010, when compared to the same period last year. Further information regarding our distributions is included below in "—Partnership Distributions."

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 2009 Form 10-K contains additional information concerning our partnership distributions, including the definition of "Available Cash," the manner in which our total distributions are divided between our general partner and our limited partners, and the form of distributions to all of our partners, including our noncontrolling interests.

On May 14, 2010, we paid a quarterly distribution of $1.07 per unit for the first quarter of 2010. This distribution was 2% greater than the $1.05 distribution per unit we paid in May 2009 for the first quarter of 2009. We paid this distribution in cash to our general partner and to our common and Class B unitholders. KMR, our sole i-unitholder, received additional i-units based on the $1.07 cash distribution per common unit. On July 21, 2010, we declared a cash distribution of $1.09 per unit for the second quarter of 2010 (an annualized rate of $4.36 per unit). This distribution was 4% higher than the $1.05 per unit distribution we made for the second quarter of 2009.

The incentive distribution that we paid on May 14, 2010 to our general partner (for the first quarter of 2010) was $249.4 million. Our general partner's incentive distribution that we paid in May 2009 (for the first quarter of 2009) was $223.2 million. The period-to-period increase 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.

Our general partner's incentive distribution for the distribution that we declared for the second quarter of 2010 is $89.8 million, and our general partner's incentive distribution for the distribution that we paid for the second quarter of 2009 was $231.8 million. The decrease in our general partner incentive distributions resulted from an agreement by our general partner to reduce its incentive distribution for the second quarter of 2010 by a combined $173.6 million, including (i) a waived incentive amount equal to $5.3 million related to equity issued to finance our acquisition of a 50% interest in Petrohawk Energy Corporation's natural gas gathering and treating business; and (ii) a reduced incentive amount of $168.3 million (including its 2% general partner's interest, total cash distributions were reduced $170.0 million), due to a portion of our cash distributions for the second quarter of 2010 being a distribution of cash from interim capital transactions (ICT Distribution), rather than a distribution of cash from operations. As provided in our partnership agreement, our general partner receives no incentive distribution on ICT Distributions. Furthermore, pursuant to the provisions of our partnership agreement, in the event of an ICT Distribution, our incentive distribution target levels should be adjusted proportionately lower (in order for our general partner to receive increased future incentive distributions); however, our general partner waived this right of adjustment.

In November 2009, we announced that we expected to declare cash distributions of $4.40 per unit for 2010, a 4.8% increase over our cash distributions of $4.20 per unit for 2009. Due to our general partner's support (described above), we do not expect the $4.40 per unit distribution to our limited partners for 2010 to be impacted by any settlement payment we made or may be required to make for reparations sought by shippers on our West Coast Products Pipelines.

Our expected growth in distributions in 2010 assumes an average West Texas Intermediate (WTI) crude oil price of approximately $84 per barrel (with some minor adjustments for timing, quality and location differences) in 2010, and based on the actual prices we have received through the date of this report and the forward price curve for WTI (adjusted for the same factors used in our 2010 budget), we currently expect to realize an average WTI crude oil price of approximately $79 per barrel in 2010. Although the majority of the cash generated by our assets is fee based and is not sensitive to commodity prices, our CO_2 business segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids, and while we hedge the majority of our crude oil production, we do have exposure on our unhedged volumes, the majority of which are natural gas liquids volumes.

Furthermore, for 2010, we expect that every $1 change in the average WTI crude oil price per barrel will impact our CO_2 segment's cash flows by approximately $6 million (or less than 0.2% of our combined business segments' anticipated earnings before depreciation, depletion and amortization expenses). This sensitivity to the average WTI price is very similar to what we experienced in 2009.

Off Balance Sheet Arrangements

Except as set forth under "—Contingent Debt—Rockies Express Pipeline LLC Debt" in Note 4 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, 2009 in our 2009 Form 10-K.

Recent Accounting Pronouncements

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

Information Regarding Forward-Looking Statements

This report 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, steel and other bulk materials and chemicals in North America;

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

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

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

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

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

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

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

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

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

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

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

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

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

- acts of nature, sabotage, terrorism or other similar acts causing damage greater than our insurance coverage limits;

- capital and credit markets conditions, inflation and interest rates;

- the political and economic stability of the oil producing nations of the world;

- national, international, regional and local economic, competitive and regulatory conditions and developments;

- our ability to achieve cost savings and revenue growth;

- foreign exchange fluctuations;

- the timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;

- the extent of our success in discovering, developing and producing oil and gas reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;

- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and workovers, and in drilling new wells;

- the uncertainty inherent in estimating future oil and natural gas production or reserves;

- the ability to complete expansion projects on time and on budget;

- the timing and success of our business development efforts; and

- unfavorable results of litigation and the fruition of contingencies referred to in Note 10 to our consolidated financial statements included elsewhere in this report.

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

See Item 1A “Risk Factors” of our 2009 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 our 2009 Form 10-K. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2009, in Item 7A of our 2009 Form 10-K. For more information on our risk management activities, see Note 6 “Risk Management” to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of June 30, 2010, 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, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

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 2009 Form 10-K.

An extended drilling moratorium in the Gulf of Mexico, or any additional regulations that cause delays or deter new drilling, could adversely affect our business.

On July 12, 2010, in response to the April 20, 2010 fire and explosion that occurred onboard the drilling rig Deepwater Horizon, leading to the oil spill currently affecting the Gulf of Mexico, the Bureau of Ocean Energy Management, Regulation and Enforcement, referred to as the BOE, issued a moratorium on drilling activities that applies to deep-water drilling operations that use subsea blowout preventers or surface blowout preventers on floating facilities. The moratorium will last until November 30, 2010, or until such earlier time that the BOE determines that deep-water drilling operations can proceed safely. The BOE is also expected to issue new safety and environmental guidelines or regulations for drilling in the U.S. Gulf of Mexico, and potentially in other geographic regions, and may take other steps that could increase the costs of exploration and production, reduce the area of operations and result in permitting delays. These actions could cause delays or deter new drilling in the U.S. Gulf of Mexico or other areas that supply volumes to our pipelines and facilities. As a result, future natural gas and crude oil volumes to our pipelines and facilities may decline or be lower than previously anticipated, which may adversely affect our financial position, results of operations and cash flows.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. (Removed and Reserved)

Item 5. Other Information.

None.

Item 6. Exhibits.

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

4.2 — Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy

Partners, L.P., establishing the terms of the 5.30% Senior Notes due September 15, 2020, and the 6.55% Senior Notes due September 15, 2040.

*10.1 — Credit Agreement dated as of June 23, 2010 among Kinder Morgan Energy Partners, L.P., Kinder Morgan Operating L.P. (“B”), the lenders party thereto, Wells Fargo Bank, National Association as Administrative Agent, Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A., and DnB NOR Bank ASA (filed as exhibit 10.1 to Kinder Morgan Energy Partners, L.P. Current Report on Form 8-K filed June 24, 2010).

11 — Statement re: computation of per share earnings.

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

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

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

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

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

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* Asterisk indicates exhibit 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.
Registrant (A Delaware limited partnership)

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

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

Date: July 30, 2010

By: /s/ Kimberly A. Dang
Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)