PART II

Item 5. *Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our common units are listed and traded on the New York Stock Exchange ("NYSE") under the symbol "PAA." As of February 22, 2010, the closing market price for our common units was $54.90 per unit and there were approximately 120,000 record holders and beneficial owners (held in street name). As of February 22, 2010, there were 136,135,988 common units outstanding.

The following table sets forth high and low sales prices for our common units and the cash distributions declared per common unit for the periods indicated:

	Common Unit Price Range		Cash
	High	Low	Distributions [1]
2009			
4th Quarter	$ 53.37	$ 45.45	$ 0.9275
3rd Quarter	$ 50.33	$ 42.50	$ 0.9200
2nd Quarter	$ 45.52	$ 36.25	$ 0.9050
1st Quarter	$ 40.98	$ 34.00	$ 0.9050
2008			
4th Quarter	$ 42.39	$ 23.25	$ 0.8925
3rd Quarter	$ 48.36	$ 35.68	$ 0.8925
2nd Quarter	$ 50.96	$ 44.54	$ 0.8875
1st Quarter	$ 52.44	$ 43.93	$ 0.8650

[1] Cash distributions for a quarter are declared and paid in the following calendar quarter. See the "Cash Distribution Policy" below for a discussion of our policy regarding distribution payments.

Our common units are used as a form of compensation to our employees. Additional information regarding our equity compensation plans is included in Part III of this report under Item 13. "Certain Relationships and Related Transactions and Director Independence."

Cash Distribution Policy

We will distribute all of our available cash to our unitholders within 45 days following the end of each quarter in the manner described below. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

In addition to distributions on its 2% general partner interest, our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication and except for the agreed upon adjustment discussed below, to 15% of amounts we distribute in excess of $0.450 per unit, 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit.

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner may agree to reduce the amounts due to it as incentive distributions. Upon closing the acquisitions of Pacific Energy Partners LP ("Pacific") in November 2006 and Rainbow Pipeline Company ("Rainbow") in May 2008, our general partner agreed to reduce the amounts due to it as incentive distributions. Additionally, in connection with the PNGS acquisition in September 2009, our general partner agreed to further reduce its incentive distributions by an aggregate of $8 million over the next two years—$1.25 million per quarter for the first four quarters and $0.75 million per quarter for the next four quarters. This incentive distribution reduction became effective upon payment of our November 2009 quarterly distribution of $0.9200 per limited partner unit. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions is $83 million as displayed on an annual basis in the following table (in millions):

Acquisition	2007	2008	2009	2010	2011	Total
Pacific	$ 20	$ 15	$ 15	$ 10	$ 5	$ 65
Rainbow	—	3	6	1	—	10
PNGS	—	—	1	5	2	8
Total	$ 20	$ 18	$ 22	$ 16	$ 7	$ 83

Following the distribution in February 2010 (as discussed below), the aggregate remaining incentive distribution reductions will be approximately $18 million.

We paid $127 million to the general partner in incentive distributions in 2009. Additionally, on February 12, 2010, we paid a quarterly distribution of $0.9275 per unit applicable to the fourth quarter of 2009, of which approximately $40 million was paid to the general partner. See Item 13. "Certain Relationships and Related Transactions, and Director Independence—Our General Partner."

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. No such default has occurred. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities and Long-Term Debt."

See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" for information regarding securities authorized for issuance under equity compensation plans.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of fiscal 2009, and we do not have any announced or existing plans to repurchase any of our common units.

Item 6. *Selected Financial Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2009, 2008, 2007, 2006 and 2005 and for the years then ended. The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in millions, except for per unit data)				
Statement of operations data:					
Total revenues [1]	$ 18,520	$ 30,061	$ 20,394	$ 22,445	$ 31,177
Income before cumulative effect of change in accounting principle [2]	$ 580	$ 437	$ 365	$ 279	$ 218
Net income	$ 580	$ 437	$ 365	$ 285	$ 218
Net income attributable to Plains	$ 579	$ 437	$ 365	$ 285	$ 218
Per unit data:					
Basic net income before cumulative effect of change in accounting principle [2]	$ 3.34	$ 2.66	$ 2.47	$ 2.85	$ 2.83
Basic net income after cumulative effect of change in accounting principle	$ 3.34	$ 2.66	$ 2.47	$ 2.93	$ 2.83
Diluted net income before cumulative effect of change in accounting principle [2]	$ 3.32	$ 2.64	$ 2.45	$ 2.82	$ 2.78
Diluted net income after cumulative effect of change in accounting principle	$ 3.32	$ 2.64	$ 2.45	$ 2.90	$ 2.78
Declared distributions per limited partner unit [3]	$ 3.62	$ 3.50	$ 3.28	$ 2.87	$ 2.58

	2009	2008	2007	2006	2005
Balance sheet data (at end of period):					
Total assets	$ 12,358	$ 10,032	$ 9,906	$ 8,715	$ 4,120
Long-term debt	$ 4,142	$ 3,259	$ 2,624	$ 2,626	$ 952
Total debt	$ 5,216	$ 4,286	$ 3,584	$ 3,627	$ 1,330
Partners' capital	$ 4,159	$ 3,552	$ 3,424	$ 2,977	$ 1,331
Other data:					
Net cash provided by (used in) operating activities	$ 365	$ 857	$ 796	$ (276)	$ 24
Net cash used in investing activities	$ (660)	$ (1,339)	$ (663)	$ (1,651)	$ (297)
Net cash provided by (used in) financing activities	$ 312	$ 464	$ (124)	$ 1,927	$ 271
Capital expenditures:					
Acquisitions	$ 393	$ 735	$ 125	$ 3,021	$ 40
Internal growth projects	$ 364	$ 491	$ 525	$ 332	$ 149
Maintenance	$ 81	$ 81	$ 50	$ 28	$ 14
Investments in unconsolidated subsidiaries	$ 15	$ 37	$ 9	$ 44	$ 113

	Year Ended December 31,				
	2009	2008	2007	2006	2005
Volumes [4] [5] [6]					
Transportation segment (average daily volumes in thousands of barrels):					
Tariff activities	2,836	2,851	2,712	2,106	1,799
Trucking	85	97	105	101	84
Transportation segment total	2,921	2,948	2,817	2,207	1,883
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	56	53	46	25	22
Natural gas storage (average monthly capacity in billion cubic feet (“Bcf”))	26	14	13	13	4
LPG processing (average daily throughput in thousands of barrels)	15	17	18	12	—
Facilities segment total (average monthly capacity in millions of barrels)	61	56	48	27	22
Supply & Logistics segment (average daily volumes in thousands of barrels):					
Crude oil lease gathering purchases	612	658	685	650	610
Refined products sales	35	26	11	N/A	N/A
LPG sales	105	103	90	70	56
Waterborne foreign crude imported	55	80	71	63	59
Supply & Logistics segment total	807	867	857	783	725

(1) Includes gross presentation of buy/sell transactions for all periods prior to the second quarter of 2006. See Note 2 to our Consolidated Financial Statements for further discussion of buy/sell transactions.

(2) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2006 change in our method of accounting for unit-based payment transactions would have been $224 million for 2005. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $2.81 ($2.76 diluted) for 2005.

(3) Our general partner is entitled, directly or indirectly, to receive 2% proportional distributions, and also incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 5 to our Consolidated Financial Statements.

(4) Volumes associated with acquisitions represent total volumes for the number of days or months we actually owned the assets divided by the number of days or months in the year.

(5) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for September 2005 through August 2009 are netted to our 50% interest in PNGS. September through December 2009 volumes represent our 100% interest in PNGS. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.

(6) Facilities total is calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes.

Our discussion and analysis includes the following:

- Executive Summary
    - Company Overview
    - Overview of Operating Results, Capital Spending and Significant Activities
- Acquisitions and Internal Growth Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

Executive Summary

Company Overview

We provide transportation, storage, terminalling, supply and logistics services with respect to crude oil, refined products and LPG. We are also engaged in the development and operation of natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. We previously referred to the Supply and Logistics segment as the Marketing segment. We revised the segment name to better describe the business activities conducted within that segment.

See "—Results of Operations—Analysis of Operating Segments" for further discussion.

Overview of Operating Results, Capital Spending and Significant Activities

During 2009, our operations provided favorable growth over 2008 and 2007 levels. All three of our segments provided favorable operating results, particularly our supply and logistics segment. The supply and logistics segment benefited from the favorable steep contango crude oil market structure early in the period. Our LPG margins also benefited from strong demand for propane. Our transportation and facilities operating results benefited from expansions in our asset base through acquisitions and our ongoing internal growth projects. Additional key items impacting 2009 include:

- The issuance of 5,750,000 common units at $36.90 per unit for net proceeds of approximately $210 million in March 2009, and the issuance of 5,290,000 common units at $46.70 per unit for net proceeds of approximately $246 million in September 2009.

- The issuance and repayment of the following senior notes:

  - Issuance of $350 million of 8.75% senior notes for net proceeds of approximately $347 million in April 2009.
  - Issuance of $500 million of 4.25% senior notes for net proceeds of approximately $497 million in July 2009.
  - Repayment of $175 million of 4.75% senior notes in August 2009.
  - Issuance of $500 million of 5.75% senior notes for net proceeds of approximately $494 million in September 2009.
  - Repayment of $250 million of 7.13% senior notes in October 2009. We also recognized a loss of approximately $4 million in conjunction with the early redemption of these notes.

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2009, 2008 and 2007 that have impacted our results of operations. The following table summarizes our capital expenditures for acquisitions, internal growth projects, maintenance capital and investments in unconsolidated entities for the periods indicated (in millions):

	For the Year Ended December 31,		
	2009	2008	2007
Acquisition capital	$ 393	$ 735	$ 125
Internal growth projects	364	491	525
Maintenance capital	81	81	50
Investment in unconsolidated entities	15	37	9
	$ 853	$ 1,344	$ 709

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our credit facilities and the issuance of senior notes. Businesses acquired impact our results of operations commencing on the effective date of each acquisition. Our acquisition and capital expansion activities are discussed further in "—Liquidity and Capital Resources" and in Note 3 to our Consolidated Financial Statements. Information regarding acquisitions completed in 2009, 2008 and 2007 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
PNGS	09/03/2009	$ 215	Facilities
Other [(1)]	Various	178	Transportation & Facilities
2009 Total		$ 393	
Rainbow	05/01/2008	$ 687	Transportation
San Pedro and other	11/13/2008	48	Facilities
2008 Total		$ 735	
Bumstead LPG Storage Facility	07/24/2007	$ 52	Facilities

Tirzah LPG Storage Facility	10/2/2007	54	Facilities
Other	Various	19	Transportation and Supply & Logistics
2007 Total		$ 125	

(1) Consists of six small acquisitions.

Internal Growth Projects

Our 2009 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2009, 2008 and 2007 projects (in millions):

Projects	2009	2008	2007
St. James - Phase III (1)	$ 71	$ 27	$ 14
Nipisi storage and truck terminal (1)	35	—	—
Kerrobert pumping project	34	9	—
Rangeland tankage	31	12	—
Cushing - Phase VII (1)	25	—	—
Patoka tankage - Phase I	6	55	30
Patoka tankage - Phase II (1)	14	1	—
Paulsboro tankage	11	30	2
Salt Lake City expansion	8	154	73
Fort Laramie tank expansion	2	20	12
St. James, Louisiana storage facility	2	17	68
Other projects (2)	125	166	326
Total	$ 364	$ 491	$ 525

(1) These projects will continue into 2010. See "—Liquidity and Capital Resources—Capital Expenditures and Distributions Paid to Our Unitholders and General Partner—2010 Capital Expansion Projects."

(2) Primarily consists of gas storage construction projects, pipeline connections, upgrades and truck stations, and new tank construction and refurbishing.

Critical Accounting Policies and Estimates

Critical Accounting Policies

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with generally accepted accounting principles in the United States. These critical accounting policies are discussed in Note 2 to our Consolidated Financial Statements.

Critical Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. The critical accounting estimates that we have identified are discussed below.

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. For the year ended December 31, 2009, we estimate that approximately 3%, 3%, 8% and 11% of annual revenues, cost of sales, operating income and net income attributable to Plains, respectively, were recorded using purchase and sales estimates. Accordingly, a 10% variance from this estimate would impact the respective line items by approximately 1% or less on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with FASB guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recognized. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. We also expense the transaction costs as incurred in connection with each acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

Impairment testing entails estimating future net cash flows relating to the asset, based on management's estimate of market conditions including pricing, demand, competition, operating costs and other factors. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable.

We also compare our market capitalization to our book equity on a quarterly basis, to determine if there may be an indicator of impairment. As of December 31, 2009, our market capitalization exceeded the book value of our equity; therefore, since there were no events or changes in circumstances indicating impairment issues, we determined that it was not necessary to perform our goodwill impairment test as of December 31, 2009 (as performed during the prior year due to economic conditions). We will continue to monitor the market and any changes in circumstances to determine if a triggering event occurs and will perform a goodwill impairment analysis if deemed necessary. We did not have any goodwill impairments in 2009, 2008 or 2007. See Note 2 to our Consolidated Financial Statements for a further discussion of goodwill.

Mark-to-Market Accrual. In situations where we are required to mark-to-market derivatives, the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total annual revenues are based on estimates derived from internal valuation models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, insurance claims, asset retirement obligations, taxes and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, costs of medical care associated with worker's compensation and employee health insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $13 million. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Equity Compensation Plan Accruals. We accrue compensation expense for outstanding equity awards granted under our various Long Term Incentive Plans as well as outstanding Class B units of Plains AAP, L.P. (collectively, our "equity compensation plans"). Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the service period. For equity awards that contain a performance condition, the fair value of the equity award is recognized as compensation expense only if the attainment of the performance condition is considered probable.

Our equity awards granted under our various Long Term Incentive Plans are accounted for as equity awards and thus, the total compensation expense recognized over the service period is determined by our unit price on the vesting date (or, in some cases, the average unit price for a range of dates preceding the vesting date) multiplied by the number of equity awards that are vesting, plus our share of associated employment taxes. Uncertainties involved in this estimate include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity awards.

For the Class B units of Plains AAP, L.P., the total compensation expense recognized over the service period is equal to the grant date fair value of the Class B units that become earned. The Class B units become earned in various increments upon us achieving annualized distribution levels of $3.50, $3.75, $4.00 and $4.50. When earned, the Class B units will be entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million (as adjusted for debt service costs and excluding special distributions funded by debt) per quarter. Uncertainties involved in this estimate include the estimated date that we will achieve the annualized distribution levels required and the continued employment of personnel who have been awarded Class B units.

We recognized total compensation expense of approximately $68 million, $24 million and $49 million in 2009, 2008 and 2007, respectively, related to equity awards granted under our various equity compensation plans. We cannot provide assurance that the actual fair value of our equity compensation awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.

Property, Plant and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. We periodically evaluate property, plant and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property, plant and equipment a critical accounting estimate. In determining the existence of an impairment of carrying value, we make a number of subjective assumptions as to:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of "holding" versus "selling" an asset;
- the forecast of undiscounted expected future cash flow over the asset's estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

During 2009, we recognized impairments of less than $1 million for assets taken out of service. Impairments of approximately $5 million and $1 million were recognized during 2008 and 2007, respectively.

Allowance for Doubtful Accounts. We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for additional discussion.

Recent Accounting Pronouncements

Recent Accounting Pronouncements

See Note 2 to our Consolidated Financial Statements for a discussion of recent accounting pronouncements that will impact us.

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics.

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 15 to our Consolidated Financial Statements for a definition of segment profit (including an explanation of why this is a performance measure) and a reconciliation of segment profit to net income attributable to Plains.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the supply and logistics segment secures transportation and facilities services from the Partnership's other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. Facilities segment services are also obtained at rates generally consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our supply and logistics segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties. Intersegment activities are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expense and general and administrative overhead expenses between segments based on management's assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

	For the Twelve Months Ended December 31,			Favorable (Unfavorable)			
				2009-2008		2008-2007	
	2009	2008	2007	$	%	$	%
	(In millions, except per unit data)						
Transportation segment profit	$ 477	$ 445	$ 334	$ 32	7%	$ 111	33%
Facilities segment profit	208	153	110	55	36%	43	39%
Supply & Logistics segment profit	345	221	269	124	56%	(48)	(18)%
Total segment profit	1,030	819	713	211	26%	106	15%
Depreciation and amortization	(236)	(211)	(180)	(25)	(12)%	(31)	(17)%
Interest expense	(224)	(196)	(162)	(28)	(14)%	(34)	(21)%
Other income, net	16	33	10	(17)	(52)%	23	230%
Income tax expense	(6)	(8)	(16)	2	25%	8	50%
Net income	580	437	365	143	33%	72	20%
Less: Net income attributable to noncontrolling interest	(1)	—	—	(1)	N/A	—	—
Net income attributable to Plains	$ 579	$ 437	$ 365	$ 142	32%	$ 72	20%
Earnings per basic limited partner unit	$ 3.34	$ 2.66	$ 2.47	$ 0.68	26%	$ 0.19	8%
Earnings per diluted limited partner unit	$ 3.32	$ 2.64	$ 2.45	$ 0.68	26%	$ 0.19	8%
Basic weighted average units outstanding	130	120	113	10	8%	7	6%
Diluted weighted average units outstanding	131	121	114	10	8%	7	6%

Transportation Segment

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. The transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees.

The following table sets forth our operating results from our transportation segment for the periods indicated:

Operating Results [1] (in millions, except per barrel amounts)	Year Ended December 31, 2009	2008	2007	Favorable (Unfavorable) 2009-2008 $	%	2008-2007 $	%
Revenues [1]							
Tariff activities	$ 867	$ 800	$ 654	$ 67	8%	$ 146	22%
Trucking	94	127	117	(33)	(26)%	10	9%
Total transportation revenues	961	927	771	34	4%	156	20%
Cost and Expenses [1]							
Trucking costs	(63)	(88)	(80)	25	28%	(8)	(10)%
Field operating costs (excluding equity compensation expense)	(333)	(331)	(288)	(2)	(1)%	(43)	(15)%
Equity compensation expense - operations [2]	(9)	(1)	(5)	(8)	(800)%	4	80%
Segment G&A expenses (excluding equity compensation expense)	(61)	(56)	(50)	(5)	(9)%	(6)	(12)%
Equity compensation expense - general and administrative [2]	(25)	(11)	(19)	(14)	(127)%	8	42%
Equity earnings in unconsolidated entities	7	5	5	2	40%	—	—
Segment profit	$ 477	$ 445	$ 334	$ 32	7%	$ 111	33%
Maintenance capital	$ 57	$ 54	$ 34	$ 3	6%	$ 20	59%
Segment profit per barrel	$ 0.45	$ 0.41	$ 0.34	$ 0.04	10%	$ 0.07	21%

Average Daily Volumes (in thousands of barrels per day) [3]	Year Ended December 31, 2009	2008	2007	Favorable (Unfavorable) 2009-2008 Volumes	%	2008-2007 Volumes	%
Tariff activities							
All American	40	45	47	(5)	(11)%	(2)	(4)%
Basin	394	377	378	17	5%	(1)	—
Capline	193	219	235	(26)	(12)%	(16)	(7)%
Line 63/Line 2000	131	147	175	(16)	(11)%	(28)	(16)%
Salt Lake City Area Systems	131	93	101	38	41%	(8)	(8)%
West Texas/New Mexico Area Systems	368	372	369	(4)	(1)%	3	1%
Manito	63	70	73	(7)	(10)%	(3)	(4)%
Rainbow	183	129	—	54	42%	129	N/A
Rangeland	53	58	63	(5)	(9)%	(5)	(8)%
Refined products	100	109	109	(9)	(8)%	—	—
Other	1,180	1,232	1,162	(52)	(4)%	70	6%
Tariff activities total	2,836	2,851	2,712	(15)	(1)%	139	5%
Trucking	85	97	105	(12)	(12)%	(8)	(8)%
Transporation segment total	2,921	2,948	2,817	(27)	(1)%	131	5%

(1) Revenues and costs and expenses include intersegment amounts.

(2) Equity compensation expense related to our equity compensation plans.

(3) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Segment profit from our pipeline capacity leases generally reflects a negotiated amount.

Transportation segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues increased in each year and our volumes remained relatively consistent for 2009 compared to 2008 and increased approximately 5% for 2008 compared to 2007. Volumes were positively impacted by (i) the Rainbow acquisition completed in May 2008, which added approximately 129,000 barrels per day to average 2008 volumes and approximately 183,000 barrels per day to average 2009 volumes and (ii) the completion in the fourth quarter of 2008 of a 94-mile expansion of our Salt Lake Area system. The increases from these acquisition and expansion activities were generally offset in 2009 and partially offset in 2008 by volume fluctuations on various other pipeline segments as well as decreased trucking volumes over the three year period. The decreased trucking volumes were primarily due to decreased demand as well as an effort to eliminate lower margin activities.

Revenues for the years ended December 31, 2009 and 2008 were positively impacted by the net effect of a number of factors including:

- The Rainbow acquisition contributed approximately $16 million and $50 million of incremental revenue to 2009 and 2008, respectively.

- Incremental revenues from completion of the Salt Lake City Area expansion added approximately $7 million to revenues in 2009 relative to 2008 associated with volume increases.

- Loss allowance revenues increased by approximately $22 million for 2009 compared to 2008 primarily related to a higher average realized price per barrel during 2009 (including the impact of gains from derivative activities). Loss allowance revenues increased by approximately $31 million for 2008 compared to 2007 due to slightly higher volumes and an increase in the average realized price per barrel during most of 2008 relative to 2007.

- Tariff rates increased on certain of our pipeline systems after the second quarter of each year as a result of indexing by the Federal Energy Regulation Commission (“FERC”). In addition, we had similar type rate increases on non-FERC regulated pipelines.

- Revenues for the year ended December 31, 2008 were impacted by a gain of approximately $17 million related to a linefill hedge entered into in conjunction with the Rainbow acquisition.

- Trucking revenues decreased for 2009 compared to 2008 by approximately $33 million, primarily related to the volume decrease discussed within our operating revenues and volumes lead in. Trucking revenues increased for 2008 compared to 2007 by approximately $10 million due to the acquisition of trucking businesses in prior years.

- Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at average exchange rates prevailing for each month. During 2009, revenues from some of our Canadian pipeline systems were unfavorably impacted by the appreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar (“CAD”) to U.S. dollar (“USD”) exchange rate for 2009 was $1.14 CAD: $1.00 USD compared to an average of $1.07 CAD: $1.00 USD in 2008 and in 2007.

- Miscellaneous revenue and volume variances on various other systems, including the impacts of Hurricanes Gustav and Ike, both of which affected the Gulf Coast area during the third quarter of 2008.

Costs and Expenses. In general, our overall transportation costs and expenses have trended up primarily due to our continued growth through acquisitions and expansion activities. However, overall costs were favorably impacted in 2009 by the appreciation of the U.S. dollar relative to the Canadian dollar. Various factors impacting components of our cost structure include:

Trucking Costs. Trucking costs decreased in 2009 as compared to 2008 primarily as a result of decreased trucking volumes, as discussed above, and as a result of lower rates resulting from lower fuel costs. Trucking cost increased in 2008 as compared to 2007 primarily as a result of increased rates resulting from higher fuel costs. This increase was partially offset by lower costs resulting from lower trucking volumes.

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) increased $2 million in 2009 over 2008 and $43 million in 2008 over 2007. The primary driver of this increase was the Rainbow acquisition that was completed in May 2008, which added $17 million for the year ended December 31, 2008, and an additional $2 million for the year ended December 31, 2009. In addition, during the year ended December 31, 2009 we had increased payroll, benefit and maintenance costs that were offset by lower API 653, in-line inspection, utility and fuel costs. Costs related to API 653 and in-line inspections had increased in 2008 in an effort to meet the 2009 compliance deadline. In addition, utility and fuel costs had increased in 2008 as a result of higher rates, and decreased again in 2009 as fuel and power rates decreased. Our overall operating expenses also increased during 2008 as compared to 2007 due to general inflationary pressures experienced in the industry and from our expanded asset base including assets from the Pacific merger in late 2006.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation charges as discussed below) have increased in 2009 compared to 2008 and in 2008 compared to 2007 related to our acquisitions and expansion activities as well as upward cost pressures from payroll and benefits and other personnel related costs.

Equity Compensation Charges. Equity compensation charges increased approximately $22 million in 2009 compared to 2008 and decreased by $12 million in 2008 as compared to 2007. Such variations are primarily the result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. At the end of 2009, our unit price was $52.85 per common unit as compared to $34.69 per common unit at the end of 2008 and $52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

Maintenance Capital. The increase in maintenance capital in 2008 compared to 2007 is primarily due to increased investment applicable to in-line inspections and API 653 repairs in an effort to meet our May 2009 compliance deadline, general inflationary pressures experienced in the industry, our expanded asset base including assets from the Pacific merger in late 2006, and the Rainbow acquisition.

Facilities Segment

Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, natural gas and LPG, as well as LPG fractionation and isomerization services. The facilities segment generates revenue through a combination of month-to-month and multi-year leases and processing arrangements.

The following table sets forth our operating results from our facilities segment for the periods indicated:

Operating Results [1] (in millions, except per barrel amounts)	For the Year Ended December 31, 2009	2008	2007	Favorable (Unfavorable) 2009-2008 $	2009-2008 %	2008-2007 $	2008-2007 %
Storage and terminalling revenues [1]	$ 362	$ 270	$ 210	$ 92	34%	$ 60	29%
Storage related costs	(5)	—	—	(5)	N/A	—	—
Field operating costs (excluding equity compensation charge)	(120)	(104)	(84)	(16)	(15)%	(20)	(24)%
Equity compensation charge - operations [2]	(1)	—	—	(1)	N/A	—	—
Segment G&A expenses (excluding equity compensation expense)	(26)	(18)	(18)	(8)	(44)%	—	—
Equity compensation expense - general and administrative [2]	(10)	(4)	(8)	(6)	(150)%	4	50%
Equity earnings in unconsolidated entities	8	9	10	(1)	(11)%	(1)	(10)%
Segment profit	$ 208	$ 153	$ 110	$ 55	36%	$ 43	39%
Maintenance capital	$ 16	$ 23	$ 10	$ (7)	(30)%	$ 13	130%
Segment profit per barrel	$ 0.29	$ 0.23	$ 0.19	$ 0.06	26%	$ 0.04	21%

Volumes [3] [4] [5]	For the Year Ended December 31, 2009	2008	2007	Favorable (Unfavorable) 2009-2008 Volumes	%	2008-2007 Volumes	%
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	56	53	46	3	6%	7	15%
Natural gas storage (average monthly capacity in bcf)	26	14	13	12	86%	1	8%
LPG processing (average throughput in thousands of barrels per day)	15	17	18	(2)	(12)%	(1)	(6)%
Facilities segment total (average monthly capacity in millions of barrels)	61	56	48	5	9%	8	17%

(1) Revenues include intersegment amounts.

(2) Equity compensation expense related to our equity compensation plans.

(3) Volumes associated with acquisitions represent total volumes for the number of months we actually owned the assets divided by the number of months in the period.

(4) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for 2008 and January through August 2009 are netted to our 50% interest in PNGS. September through December 2009 volumes represent our 100% interest in PNGS.

(5) Facilities total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

Facilities segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues and volumes increased for 2009 compared to 2008 and for 2008 compared to 2007. The significant variances in volumes and revenues between 2009, 2008 and 2007 are discussed below:

- Acquisitions — Revenues and volumes for 2009 compared to 2008 were impacted by the PNGS acquisition, which closed during the third quarter of 2009 and the acquisition of a natural gas processing business, which closed during the second quarter of 2009. Revenues and volumes for 2009 compared to 2008 were also impacted by the San Pedro acquisition, which closed during the fourth quarter of 2008. Such acquisitions contributed approximately $36 million in additional revenue for the year ended December 31, 2009.

  Revenues and volumes for 2008 compared to 2007 were impacted by the Bumstead and Tirzah acquisitions in 2007 in addition to the San Pedro acquisition that we closed during the fourth quarter of 2008. The Bumstead acquisition was completed in the third quarter of 2007 and the Tirzah acquisition was completed in the fourth quarter of 2007. Such acquisitions contributed approximately $13 million in additional revenue for the year ended December 31, 2008.

- Expansion Projects — Expansion projects also resulted in an increase in revenues and volumes in 2009 compared to 2008, which included expansion projects at the Paulsboro, Patoka, St. James and Ft. Laramie facilities. Revenues for these facilities increased by a combined $31 million for 2009. Aggregate volumes increased by approximately 5 million barrels for 2009 at these facilities.

  Expansion projects also resulted in an increase in revenues and volumes in 2008 compared to 2007, which included expansion projects at the Cushing, Martinez and St. James facilities. Revenues for these facilities increased by a combined $37 million for 2008. Aggregate volumes increased by approximately 6 million barrels for 2008 at these facilities.

- Leased Tankage — Revenues for the year ended December 31, 2009 also increased as a result of general escalations on existing leases.

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) increased in most categories during the years ended December 31, 2009 and 2008 primarily due to our continued growth through (i) additional tankage placed into service over the last few years at various terminals, including Cushing, Martinez, Paulsboro and St. James and (ii) acquisitions such as the PNGS and natural gas processing acquisitions completed in 2009 and the Tirzah and Bumstead acquisitions completed during 2007.

General and Administrative Expenses. Our general and administrative expenses (excluding equity compensation charges as discussed below) increased during the year ended December 31, 2009 primarily due to our continued growth through acquisitions, such as the PNGS and natural gas processing acquisitions completed in 2009.

Equity Compensation Charges. Equity compensation charges increased approximately $7 million in 2009 compared to 2008 and decreased approximately $4 million in 2008 as compared to 2007. Such variations are primarily as a result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. At the end of 2009, our unit price was $52.85 per common unit as compared to $34.69 per common unit at the end of 2008 and $52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

Maintenance Capital. The decrease in maintenance capital for the year ended December 31, 2009 compared to the year ended December 31, 2008 is primarily due to a decrease in API 653 repairs required to meet our May 2009 compliance deadline. The increase in maintenance capital for 2008 compared to 2007 was primarily due to maintenance capital incurred at various terminals, including the Martinez, Richmond, LA Basin and Cushing terminals to meet the 2009 deadline for API 653, general inflationary pressures experienced in the industry, and our expanded asset base including assets from the Pacific merger in late 2006.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in our supply and logistics segment volumes (which consist of (i) lease gathered crude oil purchase volumes, (ii) refined products volumes, (iii) LPG sales volumes and (iv) waterborne foreign crude oil imported) as well as the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business and our risk management activities provides a counter-cyclical balance that provides general stability in our margins, these margins are not fixed and will vary from period to period.

The following table sets forth our operating results from our supply and logistics segment for the periods indicated:

Operating Results (1) (in millions, except per barrel amounts)	For the Year Ended December 31, 2009	2008	2007	Favorable (Unfavorable) 2009-2008 $	%	2008-2007 $	%
Revenues	$ 17,759	$ 29,350	$ 19,858	$ (11,591)	(39)%	$ 9,492	48%
Purchases and related costs (2)	(17,141)	(28,873)	(19,366)	11,732	41%	(9,507)	(49)%
Field operating costs (excluding equity compensation charge)	(183)	(185)	(154)	2	1%	(31)	(20)%
Equity compensation charge - operations (3)	(1)	—	—	(1)	N/A	—	—
Segment G&A expenses (excluding equity compensation charge)	(67)	(63)	(52)	(4)	(6)%	(11)	(21)%
Equity compensation charge - general and administrative (3)	(22)	(8)	(17)	(14)	(175)%	9	53%
Segment profit	$ 345	$ 221	$ 269	$ 124	56%	$ (48)	(18)%
Maintenance capital	$ 8	$ 4	$ 6	4	100%	(2)	(33)%
Segment profit per barrel (4)	$ 1.17	$ 0.70	$ 0.86	$ 0.47	67%	$ (0.16)	(19)%

Average Daily Volumes (5) (in thousands of barrels per day)	For the Year Ended December 31, 2009	2008	2007	Favorable (Unfavorable) 2009-2008 Volumes	%	2008-2007 Volumes	%
Crude oil lease gathering purchases	612	658	685	(46)	(7)%	(27)	(4)%
Refined products sales	35	26	11	9	35%	15	136%
LPG sales	105	103	90	2	2%	13	14%
Waterborne foreign crude oil imported	55	80	71	(25)	(31)%	9	13%
Supply & Logistics segment total	807	867	857	(60)	(7)%	10	1%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately $11 million, $21 million and $44 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(3) Equity compensation expense related to our equity compensation plans.

(4) Calculated based on crude oil lease gathered volumes, refined products volumes, LPG sales volumes and waterborne foreign crude imported.

(5) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Generally, we expect a base level of earnings from our supply and logistics segment that may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. A contango market is favorable to our commercial strategies that are associated with storage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. However, in this environment, there is little incentive to store crude oil as current prices are above future delivery prices. In addition, certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average rates. Our revenues from the supply and logistics segment were unfavorably impacted in 2009 compared to 2008 as a result of the appreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar to U.S. dollar exchange rate for 2009 was $1.14 CAD: $1.00 USD compared to an average of $1.07 CAD: $1.00 USD in 2008 and in 2007.

Operating Revenues and Volume. Revenues net of purchases and related costs increased by approximately 30%, or approximately $141 million, in 2009 as compared to 2008. The primary reasons for the stronger performance in 2009 were (i) strong crude oil contango margins in the first four months of the year (during this period the contango market was as wide as $8.49 per barrel); (ii) strong LPG margins in the fourth quarter of the year due to strong crop drying demand in the quarter and colder than normal weather the latter half of the quarter; (iii) 2008 was negatively impacted by Hurricanes Gustav and Ike (we estimate the negative impact to be approximately $15 million); and (iv) derivative activities, net of inventory valuation adjustments, were a net gain of $62 million in 2009 compared to a net loss of $7 million in 2008. The derivative gains in 2009 are generally offset by future physical positions that are not included in the mark-to-market calculation for various reasons including that they qualify for the normal purchase and normal sale scope exception under FASB guidance. These items more than offset a lower net margin from our lease gathering activities, which was primarily due to lower volumes as we eliminated some of our less profitable purchases.

Revenues net of purchases and related costs decreased by approximately 3% in 2008 as compared to 2007. The primary reason for the decrease was that 2008 was negatively impacted by Hurricanes Gustav and Ike. We estimate the negative impact to be approximately $15 million. Lease gathering margins were also stronger in 2008 as compared to 2007; however, this was largely offset by a decline in crude oil contango market opportunities in 2008.

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) in 2009 were in line with 2008 costs. Field operating costs were approximately $31 million higher in 2008 than in 2007. Such costs relate primarily to our lease gathering activities where our net revenues (revenues less purchases and related costs) increases more than offset the cost increases in 2008.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation charges as discussed below) increased approximately 6% in 2009 compared to 2008, primarily due to increased payroll and benefit costs. Similarly, such costs increased in 2008 as compared to 2007 due to (i) increased payroll and benefit costs and (ii) a change in allocation methodology between the facilities and supply and logistics segments.

Equity Compensation Charges. Equity compensation charges increased approximately $15 million in 2009 compared to 2008 and decreased approximately $9 million in 2008 as compared to 2007. Such variations are primarily as a result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. At the end of 2009, our unit price was $52.85 per common unit as compared to $34.69 per common unit at the end of 2008 and $52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital for the year ended December 31, 2009 compared to the year ended December 31, 2008 is primarily due to truck and trailer fleet replacements and rebuilds.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $236 million for the year ended December 31, 2009 compared to $211 million and $180 million for the years ended December 31, 2008 and 2007, respectively. The increases in 2009, 2008 and 2007 related primarily to an increased amount of depreciable assets stemming from our acquisition activities and internal growth projects. Amortization of debt issue costs was $6 million, $4 million and $3 million in 2009, 2008 and 2007, respectively.

Included in depreciation expense for the years ended December 31, 2009, 2008 and 2007 is a net loss of $1 million, a net gain of $6 million and a net loss of approximately $7 million, respectively, recognized upon disposition of certain inactive assets. Also included within depreciation expense for the year ended December 31, 2009 and 2008 is an impairment of less than $1 million and $5 million, respectively, for assets taken out of service.

Interest Expense

Interest expense was $224 million for the year ended December 31, 2009, compared to $196 million and $162 million for the years ended December 31, 2008 and 2007, respectively. Interest expense is primarily impacted by:

- our weighted average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith;
- market interest rates and our interest rate hedging activities on floating rate debt; and
- interest capitalized on capital projects.

The following table summarizes selected components of our weighted average debt balances (in millions):

	For the year ended December 31,					
	2009		2008		2007	
	Total	% of Total	Total	% of Total	Total	% of Total
Fixed rate senior notes [1]	$ 3,722	95%	$ 3,028	87%	$ 2,625	95%
Borrowings under our revolving credit facilities [2]	207	5%	456	13%	150	5%
Total	$ 3,929		$ 3,484		$ 2,775	

(1) Weighted average face amount of senior notes, exclusive of discounts and premiums.

(2) Excludes borrowings under our senior secured hedged inventory facility and the short-term portion of our senior unsecured revolving credit facility, as the associated interest expense is recorded in "Purchases and related costs" on our consolidated income statement.

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2009 and 2008 (in millions, except for percentages):

	$	Average LIBOR Rate	Weighted Average Interest Rate [1]
Interest expense for the year ended December 31, 2007	$ 162	5.2%	6.3%
Impact of issuance of senior notes [2]	27		
Impact of increased borrowings under credit facilities [3]	5		
Impact of increased capitalized interest	(3)		
Other	5		
Interest expense for the year ended December 31, 2008	$ 196	2.7%	5.9%
Impact of retirement of senior notes [4]	(7)		
Impact of issuance of senior notes [5]	53		
Impact of decreased borrowings under credit facilities [3]	(15)		
Impact of decreased capitalized interest	2		
Other	(5)		
Interest expense for the year ended December 31, 2009	$ 224	0.3%	6.0%

(1) Excludes commitment and other fees.

(2) The $600 million senior notes were issued in April 2008 in connection with the Rainbow acquisition.

(3) The change primarily reflects varying borrowing requirements for inventory-related borrowings and other working capital items and changes in LIBOR rates. As further discussed below, during 2009 we utilized a portion of our $500 million 4.25% senior notes due 2012 to fund our hedged inventory requirements. Therefore, we were able to reduce our short-term debt borrowing since such activities were not solely funded on our credit facilities.

(4) In August 2009, our outstanding $175 million 4.75% senior notes due 2009 matured and were paid. In October 2009, we redeemed our outstanding $250 million 7.13% senior notes due 2014.

(5) In April, July and September 2009 we completed the issuances of $350 million of 8.75% senior notes due 2019, $500 million of 4.25% senior notes due 2012 and $500 million of 5.75% senior notes due 2020, respectively. A fluctuating portion of the 4.25% senior notes due 2012 is utilized to fund hedged inventory and would be classified as short-term debt if such activities were funded through our credit facilities. Interest costs attributable to borrowings for inventory stored in a contango market are included in "Purchases and related costs" in our supply and logistics segment profits as we consider interest on these borrowings a direct cost to storing the inventory. The costs applicable to the portion of the $500 million of 4.25% senior notes that was recognized within purchases and related costs was approximately $1 million for the year ended December 31, 2009.

In April 2008, we completed the issuance of our $600 million 6.5% senior notes due 2018. Therefore, these senior notes were outstanding for approximately eight months of the year compared to twelve months during 2009.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our supply and logistics segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately $11 million, $21 million and $44 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Other Income, Net

Other income, net for the year ended December 31, 2009, primarily included (i) a net gain of approximately $9 million recognized in connection with the PNGS acquisition (see Note 3 to our Consolidated Financial Statements for further discussion), (ii) a net gain of approximately $11 million related to the foreign currency revaluation of a CAD-denominated interest receivable associated with an intercompany note and the impact of related foreign currency hedges, and (iii) a loss of approximately $4 million recognized in conjunction with the early redemption of our $250 million 7.13% senior notes.

Other income, net for the year ended December 31, 2008, primarily included (i) a gain of $14 million resulting from the sale of our NYMEX seats and shares in NYMEX Holdings, Inc., which merged with CME Group Inc. and (ii) a gain of $11 million on the foreign currency hedge and commodity price risk hedge that we entered into in connection with the Rainbow acquisition.

Income Tax Expense

Our income tax expense decreased by $2 million from $8 million in 2008 to $6 million in 2009 as a result of a decrease of Canadian taxable income.

Excluding the $10 million impact of the initial adoption of the revised Canadian tax laws in 2007, our income tax expense increased by $2 million in 2008 compared to 2007 primarily due to the Rainbow acquisition. Income tax expense was $16 million for the year ended December 31, 2007 primarily due to revised rules on Canadian taxation on certain flow-through entities and the introduction of the Texas margin tax. See Note 7 to our Consolidated Financial Statements for further discussion.

Outlook

During 2008 and 2009, worldwide financial markets were extremely volatile and the global economy substantially weakened. The U.S. government and governments around the world took significant actions in response, including an attempt to provide liquidity and stability to the financial markets by providing government assistance to some of the largest financial institutions in the world. Although it appears that these collective actions have been successful in stabilizing the financial markets, we continue to maintain a cautious outlook for the overall economic environment. Certain recent data signal improvements in the health of the economy have started to occur, while other data indicate that we have yet to begin a sustainable recovery. For example, one indicator of the strength and velocity of the economy that also has an influence on our business is energy consumption. Based on data available through early 2010, U.S. demand for petroleum has declined by approximately 10% from levels experienced during the 2005 to 2007 time period and natural gas demand has declined approximately 2% to 3% relative to 2008.

Although we expect that the U.S. economy will ultimately rebound and energy demand will return to a growth profile, these conflicting signals lead us to believe that significant uncertainty remains regarding the timing of the recovery, which translates into potential near-term risks for the energy sector. We will not be unaffected by challenging economic and capital markets conditions, however, our business strategy is designed to manage a volatile environment, and we believe that our asset base strategically positions us to benefit from certain of these developments. However, there can be no assurance that we will not be negatively affected by this volatility or the challenging capital markets conditions, or that our acquisition and expansion efforts will be successful. See Item 1A. "Risk Factors - Risks Related to Our Business."

Liquidity and Capital Resources

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At December 31, 2009, we had approximately $1.0 billion of liquidity available to meet our ongoing operational, investing and finance needs as noted below (in millions):

		As of December 31, 2009
Availability under our senior unsecured revolving credit facility	$	751
Availability under our senior secured hedged inventory facility		200
Cash and cash equivalents		25
Total	$	976

At December 31, 2009, we had a working capital deficit of approximately $124 million. We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a material adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. "Risk Factors" for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

Cash Flow from Operations

The primary drivers of cash flow from our operations are (i) the collection of amounts related to the sale of crude oil and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services, and (ii) the payment of amounts related to the purchase of crude oil and other products and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except (i) in the months that we store the purchased crude oil and hedge it by selling it forward for delivery in a subsequent month because of contango market conditions or (ii) in months in which we increase our share of linefill in third party pipelines. In addition, our cash flow from operations may be impacted by the timing of settlement of our derivative activities. Gains and losses from settled instruments that qualify as effective cash flow hedges are deferred in AOCI, but may impact operating cash flow in the period settled.

The storage of crude oil in periods of a contango market, when the price of crude oil for future deliveries is higher than current prices, can have a material impact on our cash flows from operating activities. In the month we pay for the stored crude oil, we borrow under our credit facilities (or pay from cash on hand) to pay for the crude oil, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, but to a lesser extent, the level of LPG and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it and we do not rely on borrowings under our credit facilities to pay for the crude oil. During such market conditions, our accounts payable and accounts receivable generally move in tandem as we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. In periods during which we build inventory or linefill, regardless of market structure, we may rely on our credit facilities to pay for the inventory or linefill.

Our cash flow from operations was positively impacted by cash generated by our recurring operations. Our cash flow from operations can be significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During 2009, we increased the amount of our inventory. The increase in inventory was due to both increased volumes and an increase in prices and was primarily related to our crude oil contango market storage activities. The net increased levels of inventory were financed through borrowings under our credit facilities and senior note issuances resulting in a negative impact to our operating cash flow for the period.

During 2008, we also increased the amount of our inventory; however, these volumetric increases were offset by lower prices for our inventory stored at the end of the year compared to prior year amounts. The net proceeds received during the year were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities. The settlement of gains on derivatives that have been deferred in AOCI also had a significant positive impact in 2008 on our operating cash flows. During 2007 we reduced our overall inventory levels as we liquidated inventory that had been stored in the contango market. The proceeds from liquidating the inventory were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities.

Credit Facilities and Long-Term Debt

At December 31, 2009, we had approximately $751 million of available borrowing capacity under our $1.6 billion committed revolving credit facility. Of the capacity we utilized at December 31, 2009, approximately $76 million was associated with outstanding letters of credit and the remainder was borrowed. The majority of these borrowings relate to funding short term inventory purchases of LPG and crude oil. This credit facility, among other things, has a maturity date of July 2012, contains no Material Adverse Change language and can be expanded to $2.0 billion, subject to additional lender commitments. See Note 4 to our Consolidated Financial Statements.

At December 31, 2009, we had approximately $200 million of availability under our $500 million committed hedged inventory facility. The facility's committed amount may be increased to $1.2 billion, subject to obtaining additional commitments from lenders. This facility is a committed working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. The facility matures on an annual basis beginning in October 2010.

We also have several issues of senior debt outstanding that total approximately $4.2 billion, excluding premium or discount, and range in size from $150 million to $600 million and mature at various dates through 2037.

Our credit agreements and the indentures governing our senior notes contain cross-default provisions. A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures. See Note 4 to our Consolidated Financial Statements.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding acquisitions and internal capital projects, and short-term working capital and hedged inventory borrowings related to our LPG business and contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

We periodically access the capital markets for both equity and debt financing. As of December 31, 2009, approximately $2.0 billion of unsold securities remained available under our shelf registration statement declared effective on December 16, 2009. We also have access to a universal shelf registration statement, which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs.

Equity Offerings. During the last three years we completed several equity offerings as summarized in the table below (net proceeds in millions). Certain of these offerings involved related parties. See Note 9 to our Consolidated Financial Statements.

2009		2008		2007	
Units	Net Proceeds [1]	Units	Net Proceeds [1]	Units	Net Proceeds [1]
11,040,000......	$ 456	6,900,000	$ 315	6,296,172	$ 383

(1) Includes our general partner's proportionate capital contribution and is net of costs associated with the offering.

Senior Notes. During the last three years we completed the sale of senior unsecured notes as summarized in the table below (in millions).

Year	Description	Maturity	Face Value	Net Proceeds[1]
2009	5.75% Senior Notes issued at 99.523% of face value [2]	January 2020	$ 500	$ 494
	4.25% Senior Notes issued at 99.802% of face value	September 2012	$ 500	$ 497
	8.75% Senior Notes issued at 99.994% of face value	May 2019	$ 350	$ 347
2008	6.5% Senior Notes issued at 99.424% of face value	May 2018	$ 600	$ 597

(1) Face value of notes less the applicable premium or discount (before deducting for initial purchaser discounts, commissions and offering expenses).

(2) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, a portion of which was used to fund the cash requirements of the PNGS acquisition (which included repayment of all of PNGS's debt). In addition, we used a portion of the proceeds to redeem all of our outstanding $250 million 7.13% senior notes due 2014 (in conjunction with the early redemption of these notes, we recognized a loss of approximately $4 million).

On August 15, 2009, our $175 million senior notes matured. We utilized cash on hand and available capacity under our credit facilities to retire these senior notes.

Credit Facilities. During the year ended December 31, 2009, we had net borrowings on our revolving credit facility and our hedged inventory facility of approximately $1 million. During the year ended December 31, 2008, we had net working capital and hedged inventory borrowings of approximately $90 million. These net borrowings were used primarily for purchases of LPG inventory that was stored. During the year ended December 31, 2007, we had net working capital and hedged inventory repayments of approximately $54 million. These repayments resulted primarily from sales of crude oil inventory that was stored and subsequently liquidated as we transitioned to backwardated market conditions, partially offset by higher levels of stored LPG inventory. See "—Cash Flow from Operations" above.

Capital Expenditures and Distributions Paid to Our Unitholders and General Partner

We use cash primarily for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. See "—Acquisitions and Internal Growth Projects" for further discussion for such capital expenditures.

Acquisitions. The price of the acquisitions includes cash paid, assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year.

2010 Capital Expansion Projects. The majority of funding for our 2010 capital program will be provided by revolver borrowings and cash flow in excess of partnership distributions. This will allow us to fund these capital projects without need to access the capital markets for equity or debt. Our 2010 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects	**2010**
Patoka - Phase III	$ 24
West Texas gathering lines	18
Bumstead facility upgrade	17
Cushing - Phase VII	17
Cushing - Phase VIII	15
St. James - Phase III	15
Wichita Falls tanks	11
Martinez tanks	9
Other projects, including acquisition related expansion projects (1)	234
	$ 360

(1) Primarily consists of gas storage construction projects, pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2009.

Distributions to unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On February 12, 2010, we paid a quarterly distribution of $0.9275 per limited partner unit. This distribution represented a year-over-year distribution increase of approximately 3.9%. See Note 5 to our Consolidated

Financial Statements for details of distributions paid. Also, see Item 5. "Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy" for additional discussion on distribution thresholds.

Upon closing of the Pacific, Rainbow and PNGS acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. See Note 5 to our Consolidated Financial Statements for details related to the general partner's incentive distribution reductions.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are subject to business and operational risks, however, that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

See Note 11 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to creditworthy entities.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2009 (in millions):

	Total	2010	2011	2012	2013	2014	2015 and Thereafter
Long-term debt and interest payments[1]	$ 7,150	$ 66	$ 260	$ 260	$ 950	$ 472	$ 5,142
Leases [2]	491	79	62	54	33	23	240
Other long-term liabilities[3]	234	118	25	22	23	3	43
Subtotal	7,875	263	347	336	1,006	498	5,425
Crude oil, LPG and other purchases[4]	5,429	4,201	820	379	16	2	11
Total	$ 13,304	$ 4,464	$ 1,167	$ 715	$ 1,022	$ 500	$ 5,436

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at December 31, 2009, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for (i) storage, (ii) rights-of-way, (iii) office rent and (iv) trucks used in our gathering activities.

(3) Excludes a non-current liability of approximately $35 million related to derivative activity included in crude oil and LPG purchases.

(4) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2009 and 2008, we had outstanding letters of credit of approximately $76 million and $51 million, respectively. The change in the value of outstanding letters of credit is impacted primarily by the fluctuation of market prices and the timing of foreign cargo purchases.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 307 of Regulation S-K.

Investments in Unconsolidated Entities

We have invested in entities that are not consolidated in our financial statements. Certain of these entities are borrowers under credit facilities. We are neither a co-borrower nor a guarantor under any such facilities. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2009 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Settoon Towing........	Barge Transportation Services	50%	$ 92	$ —	$ 53
Frontier....................	Crude Oil Pipeline	22%	$ 27	$ 3	$ —
Butte.........................	Crude Oil Pipeline	22%	$ 19	$ 5	$ —

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

We are exposed to various market risks, including volatility in (i) commodity prices for crude oil, refined products, natural gas and LPG, (ii) interest rates and (iii) currency exchange rates. We utilize various derivative instruments to manage such exposure and, in certain circumstances, to realize incremental margin during volatile market conditions. In analyzing our risk management activities, we draw a distinction between enterprise level risks and trading related risks. Enterprise level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the our business; rather, those risks arise as a result of engaging in the trading activity. Our policy is to manage the enterprise level risks inherent in our core businesses, rather than trying to profit from trading activity. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX, ICE and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure our hedging activities address our market risks. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. Our approved strategies are intended to mitigate and manage enterprise level risks that are inherent in our core businesses. To hedge the risks discussed above, we engage in risk management activities that we categorize by the risks we are hedging. The following discussion addresses each category of risk.

Commodity Price Risk

We use derivative instruments and physical delivery contracts to hedge our exposure to price fluctuations with respect to crude oil, refined products, natural gas and LPG in storage, and anticipated purchases and sales of these commodities. The derivative instruments utilized consist primarily of futures, options and swaps traded on the NYMEX and ICE and in over-the-counter transactions, including swaps and options contracts. Our policy is to purchase only commodity products for which we have a market, and to structure our sales contracts so that price fluctuations for those products do not materially affect the segment profit we earn. We do not acquire and hold futures contracts or physical commodities for the purpose of speculating on price changes, as these activities could expose us to significant losses.

Although we seek to maintain a position that is substantially balanced within our various commodity purchase and sales activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives are recognized in earnings, and result in greater potential for earnings volatility. This accounting treatment is discussed further in Note 2 to our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2009 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10% price decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ 39	$ 82
Swaps and options contracts	(14)	$ 27
LPG and other:		
Futures contracts	(13)	—
Swaps and options contracts [(1)]	(16)	$ (13)
Total Fair Value	$ (4)	

(1) Amount includes a liability of approximately $7 million associated with LPG physical contracts not eligible for the normal purchase and normal sale scope exception under FASB guidance.

The fair value of our exchange-traded contracts is based on quoted market prices obtained from the NYMEX or ICE. The fair value of our over-the-counter swaps and options contracts is estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. These quotes are compared to the contract price of the swap, which approximates the gain or loss that would have been realized if the contracts had been closed out at year end. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. The assumptions used in these estimates as well as the source for the estimates are maintained by the independent risk control function. See Note 6 to our Consolidated Financial Statements for further discussion. Price-risk sensitivities were calculated by assuming an across-the-board 10% decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

Interest Rate Risk

We use both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities. Therefore, from time to time we use interest rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. All of our senior notes are fixed rate notes and thus not subject to market risk. Substantially all of our variable rate debt at December 31, 2009, approximately $1.4 billion (including $300 million of interest rate derivatives that swap fixed rate debt for floating), is short-term debt and is subject to interest rate re-sets, which range from a week to three months. The average interest rate of 1.3% is based upon rates in effect at December 31, 2009. The fair value of our interest rate derivatives is an unrealized gain of approximately $2 million as of December 31, 2009. A 10% decrease in the forward LIBOR curve as of December 31, 2009 would result in an increase of approximately $1 million to the fair value of our interest rate derivatives. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates. See Note 6 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Risk

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks associated with our exposure to fluctuations in the U.S Dollar-to-Canadian Dollar exchange rate. These instruments primarily include forward exchange contracts, foreign currency forwards and options. The fair value of these instruments is an unrealized gain of approximately $1 million as of December 31, 2009. A 10% decrease in the exchange rate (Canadian dollars to U.S. dollars) would result in an increase of approximately $8 million to the fair value of our foreign currency derivatives. See Note 6 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Item 8. ***Financial Statements and Supplementary Data***

See “Index to the Consolidated Financial Statements” on page F-1.

Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

We maintain written “disclosure controls and procedures,” which we refer to as our “DCP.” The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in a manner that allows for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report. Based on this review, our Chief Executive Officer and Chief Financial Officer have found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. “Internal control over financial reporting” is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2009. See Management’s Report on Internal Control Over Financial Reporting on page F-2.

Item 9B. ***Other Information***

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2009 that has not previously been reported.