third quarter | 2008

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EnCana generates third quarter cash flow of US$2.8 billion or $3.74 per share – up 28 percent

Operating earnings up 40 percent to $1.92 per share or $1.4 billion

Total natural gas and oil production increases 6 percent

Calgary, Alberta, (October 23, 2008) – EnCana Corporation (TSX & NYSE: ECA) generated strong increases in cash flow and operating earnings in the third quarter of 2008 as a result of solid production growth and higher commodity prices compared to the same period in 2007. Third quarter natural gas and oil production increased 6 percent, led by a 16 percent rise in production from key natural gas resource plays.

"These strong financial results in the third quarter are a reflection of the company's focus on operating excellence and capital discipline. EnCana's prudent financial approach and low-risk business model allow us to capture the upside during times of higher commodity prices as well as sustain us through a volatile natural gas and oil pricing environment," said Randy Eresman, EnCana's President & Chief Executive Officer.

"In this period of economic uncertainty, our resource play strategy maintains a steadfast focus on low-cost production. As part of our ongoing efforts to maintain financial resilience and flexibility, we will continue to take steps to reduce pricing risk through our natural gas price hedging program. The company also maintains financial strength with a conservative and prudent approach that mitigates risks associated with borrowing. About 78 percent of EnCana's outstanding debt is comprised of long-term, fixed-rate debt with an average remaining term of more than 14 years," Eresman said.

EnCana increases gas price hedges
Over the next year, EnCana has a substantial portion of expected future production hedged at strong prices. About 80 percent of EnCana's total current production is natural gas. For the 2009 gas year, which runs from November 2008 through October 2009, EnCana has about 2.5 billion cubic feet per day (Bcf/d) – about 60 percent of current production – hedged at an average price of $9.15 per thousand cubic feet (Mcf).

<u>Third Quarter 2008 Highlights</u>
(all year-over-year comparisons are to the third quarter of 2007)

Financial – US$
- Cash flow increased 28 percent per share to $3.74, or $2.8 billion
- Operating earnings increased 40 percent per share to $1.92, or $1.4 billion
- Net earnings increased to $3.55 billion, primarily due to after-tax unrealized mark-to-market gains on risk management activities of $2.0 billion in 2008 compared with losses of $69 million in 2007
- Operating cash flow from the Integrated Oil division was $139 million, down 70 percent
- Capital investment, excluding acquisitions and divestitures, was in line with guidance at $1.6 billion, up 1 percent over 2007
- Free cash flow increased $578 million to $1.2 billion (free cash flow is defined in Note 1 on page 8)
- Realized natural gas prices increased 18 percent to $7.94 per Mcf and realized oil and natural gas liquids (NGLS) prices were up 85 percent to $90.88 per barrel (bbl). These prices include the impact of financial hedges

- Net debt to capitalization ratio of 26 percent
- Net debt to adjusted EBITDA of 0.6 times.

Operating – Upstream

- Total natural gas, oil and NGLs production increased 6 percent to 4.7 Bcfe/d
- Production from key natural gas resource plays increased 16 percent
- Total natural gas production increased 8 percent to 3.9 Bcf/d
- Total oil and NGLs production was approximately 133,600 barrels per day (bbls/d), down about 2 percent
- Production from Foster Creek and Christina Lake increased 10 percent to approximately 63,000 bbls/d (31,500 bbls/d net to EnCana)
- Operating and administrative costs of 79 cents per thousand cubic feet equivalent (Mcfe) decreased 22 percent from $1.01 a year earlier, largely due to mark-to-market accounting in the valuation of the cost of long-term incentives.

Operating – Downstream

- Refined products averaged 438,000 bbls/d (219,000 bbls/d net to EnCana), down 10 percent
- Refinery crude utilization of 91 percent or 412,000 bbls/d crude throughput (206,000 bbls/d net to EnCana), down 10 percent from the third quarter of 2007 due primarily to unplanned refinery outages and maintenance activities at Wood River
- The Wood River Coker and Refinery Expansion (CORE) project received regulatory approvals and construction is expected to be completed over the next three years at a cost of $3.6 billion ($1.8 billion net to EnCana).

Majority of net earnings year-over-year increase related to unrealized mark-to-market accounting gains

EnCana's net earnings in the third quarter increased to $3.55 billion. Approximately $2.0 billion of this increase was an after-tax unrealized gain due to mark-to-market accounting for hedging contracts. This large gain in net earnings resulted from a large decrease in commodity prices during the third quarter. The gain essentially reversed unrealized mark-to-market losses that were included in net earnings earlier in the year when natural gas prices were rising. It is because of these dramatic mark-to-market accounting swings in net earnings that EnCana focuses on operating earnings as a better measure of quarter-over-quarter earnings performance. Operating earnings in the third quarter, which do not include mark-to-market accounting for unrealized gains and losses, were up about 40 percent, which reflects the stronger realized prices – up about 31 percent – in the third quarter of 2008 compared to 2007, plus EnCana's 6 percent increase in daily production.

Guidance for total cash flow narrowed to range of $10 billion to $10.4 billion

Based on the company's natural gas production and commodity price expectations for the remainder of the year, EnCana is narrowing its 2008 guidance for total cash flow to a range of $10 billion to $10.4 billion, or between $13.30 and $13.85 per share. Operating cash flow has been revised to between $11.9 billion and $12.7 billion. Capital investment, including acquisitions, was ahead of expectations at the end of the third quarter mostly due to additional unconventional natural gas land acquisitions in Haynesville in Louisiana and Montney in British Columbia. EnCana had expected to complete a number of divestitures in the fourth quarter to offset these acquisitions. However, as a result of the current economic climate, some of those transactions may not be completed prior to year end. Based on current expectations, net acquisition and divestiture capital investment guidance has increased $900 million. In total, capital expenditures for the year, including acquisitions and divestitures, are expected to be about $7.4 billion, compared to $6.5 billion provided in previous guidance. Total natural gas, oil and NGLs production is on track to meet full-year guidance of 4.64 MMcfe/d. Updated guidance is posted on the company's website at www.encana.com.

Production from key natural gas resource plays up 16 percent in third quarter

Natural gas production increased 8 percent or 287 MMcf/d in the third quarter of 2008 compared with the third quarter of 2007, largely due to a 16 percent increase in production from EnCana's key natural gas resource plays. The application of new technology helped reduce costs for many of the company's key resource plays, resulting in improved well performance and continued efficiency gains. Production increases were led by a rise of 135 percent at East Texas, where production averaged about 340 MMcf/d in the third quarter, mainly due to new wells coming on production and the doubling of EnCana's interest in Deep Bossier in late 2007. Drilling and operational success at Fort Worth, Piceance and Jonah also contributed to the third quarter natural gas production increase of 24 percent in key resource plays in the U.S. Gas production from the Canadian Foothills division key resource plays increased 19 percent in 2008 compared with 2007. Drilling success and new facilities in the key resource plays of Coalbed Methane (CBM), Cutbank Ridge and Bighorn increased production by 23 percent, which was partially offset by natural declines from conventional properties.

Integrated Oil division getting set for production increase

Integrated Oil generated $139 million in operating cash flow, down 70 percent from $468 million in the same quarter of 2007. Foster Creek and Christina Lake operations contributed $183 million, a 190 percent increase due to strong heavy oil prices. Operating cash flow includes a $96 million operating loss from the downstream business, a decrease of 128 percent due to weaker market crack spreads, unplanned refinery outages and hurricane-related crude oil supply disruptions. Downstream operating cash flow includes a decrease of $95 million due to higher purchased product costs as a result of processing higher-priced crude during the quarter. The Chicago 3-2-1 crack spread averaged $17.29 per bbl in the quarter, down 6 percent from $18.48 per bbl, in the same period last year.

"Expansion activity is progressing as scheduled at our integrated oil facilities. Foster Creek is currently producing about 56,000 bbls/d (28,000 bbls/d net to EnCana). Steaming of the reservoir is underway as we near completion of the next two expansion phases, which are expected to double production capacity at Foster Creek to about 120,000 bbls/d in 2009. Christina Lake is now producing 12,000 bbls/d (6,000 bbls/d net to EnCana) and the most recent expansion at the facility has increased production capacity to 18,000 bbls/d," Eresman said.

Wood River refinery expansion receives regulatory approvals

EnCana announced on September 24, 2008 that construction of the CORE project would begin at the Wood River refinery in Roxana, Illinois. The project, a 50-50 venture of EnCana and the refinery operator ConocoPhillips, is expected to increase total crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d, more than double current heavy crude refining capacity to 240,000 bbls/d as well as increase clean product yield by 10 percent to approximately 89 percent. The CORE project is estimated to cost about $3.6 billion ($1.8 billion net to EnCana) and is expected to be completed over the next three years.

Shale gas plays continue to show promise

"In the third quarter of 2008, we strengthened our position in the Haynesville gas resource play by acquiring 25,000 net acres, increasing our land position to about 400,000 net acres, plus 63,000 net acres of mineral rights. We continue to see great potential in this promising shale play," Eresman said. "EnCana, along with our partner, Shell Exploration & Production, has an industry-leading land position in this area of Louisiana. We currently have six rigs running with a focus on cost reduction and completion optimization. We will target drilling and completing the first well in the mid-Bossier shale in the fourth quarter. In northeast British Columbia and northwestern Alberta, our already strong land position in the Montney play has expanded to more than 700,000 acres. With that, EnCana has the largest disclosed land base in this emerging unconventional gas field. And, at Horn River in British Columbia, EnCana and partner Apache Corporation have completed seven wells this year, with one of our most recent wells delivering encouraging results, flowing for the first 30 days at an average of almost 8 MMcf/d."

EnCana increases ownership in Deep Panuke

In August 2008, EnCana acquired additional interests in one of the licenses making up the Deep Panuke natural gas field offshore Nova Scotia. EnCana now owns substantially all of the Deep Panuke field. The $700 million Deep Panuke project is on budget and on schedule to begin producing first gas in late 2010.

Weak U.S. Rockies gas prices prompt production shut-in at Jonah

Due to lower natural gas prices in the U.S. Rockies region, EnCana has shut in approximately 50 MMcf/d of production (net of royalties) at the company's Jonah key resource play in Wyoming. Although EnCana hedged 100 percent of expected production from the Rockies region, production levels have been higher than anticipated, creating a small exposure to Rockies spot prices. As a result, EnCana has decided to limit production at Jonah to 580 MMcf/d (net of royalties) for October. If prices improve, EnCana will re-evaluate a return to productive capacity. Also, during September, a testing outage of the Rockies Express Pipeline resulted in lower gas prices in the U.S. Rockies region, prompting EnCana to shut-in approximately 60 MMcf/d (5 MMcf/d annualized).

IMPORTANT NOTE: Effective January 2, 2007, EnCana established an integrated oil business with ConocoPhillips, which resulted in EnCana contributing its interests in Foster Creek and Christina Lake into an upstream partnership owned 50-50 by the two companies. Production and wells drilled from 2006 have been adjusted on a pro forma basis to reflect the integrated oil transaction. Per share amounts for cash flow and earnings are on a diluted basis. EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report production, sales and reserves on an after-royalties basis. The company's financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP).

Financial Summary – Total Consolidated

(for the period ended Sept 30) ($ millions, except per share amounts)	**Q3 2008**	Q3 2007	% Δ	**9 months 2008**	9 months 2007	% Δ
Cash flow[1]	**2,809**	2,218	+27	**8,087**	6,519	+24
Per share diluted	**3.74**	2.93	+28	**10.75**	8.49	+27
Operating earnings[1]	**1,442**	1,032	+40	**3,956**	3,251	+22
Per share diluted	**1.92**	1.37	+40	**5.26**	4.24	+24
Net earnings	**3,553**	934		**4,867**	2,877	
Per share diluted	**4.73**	1.24		**6.47**	3.75	
Capital investment	**1,588**	1,575	+1	**5,155**	4,230	+22

Earnings Reconciliation Summary – Total Consolidated

Net earnings (loss)	**3,553**	934		**4,867**	2,877	
(Add back losses & deduct gains)						
Unrealized mark-to-market hedging gain (loss), after-tax	**2,043**	(69)		**1,071**	(445)	
Non-operating foreign exchange gain (loss), after-tax	**(31)**	(54)		**(259)**	(50)	
Gain (loss) on discontinuance, after-tax	**99**	25		**99**	84	
Future tax recovery due to tax rate reductions	**-**	-		**-**	37	
Operating earnings[1]	**1,442**	1,032	+40	**3,956**	3,251	+22
Per share diluted	**1.92**	1.37	+40	**5.26**	4.24	+24

1 Cash flow and operating earnings are non-GAAP measures as defined in Note 1 on page 8.

Production & Drilling Summary

Total Consolidated

(for the period ended Sept 30) (After royalties)	**Q3 2008**	Q3 2007	% Δ	**9 months 2008**	9 months 2007	% Δ
Natural Gas (MMcf/d)	**3,917**	3,630	+8	**3,830**	3,513	+9
Natural gas production per 1,000 shares (Mcf)	**480**	445	+8	**1,399**	1,263	+11
Oil and NGLs (Mbbls/d)	**134**	136	-2	**133**	133	-
Oil and NGLs production per 1,000 shares (Mcfe)	**99**	100	-1	**291**	288	+1
Total Production (MMcfe/d)	**4,718**	4,448	+6	**4,627**	4,314	+7
Total per 1,000 shares (Mcfe)	**579**	545	+6	**1,690**	1,551	+9
Total net wells drilled	**730**	1,339	-45	**2,282**	3,171	-28

Growth from key North American resource plays

Resource Play	**Daily Production**									
	2008				2007					2006
(After royalties)	**YTD**	**Q3**	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas (MMcf/d)										
Jonah	**613**	**615**	630	595	557	612	588	523	504	464
Piceance	**387**	**407**	383	372	348	351	354	349	334	326
East Texas	**309**	**339**	316	273	143	187	144	139	103	99
Fort Worth	**142**	**148**	137	140	124	138	128	124	106	101
Greater Sierra	**217**	**228**	219	205	211	221	220	219	186	213
Cutbank Ridge[1]	**291**	**322**	280	271	258	283	269	248	232	189
Bighorn[1]	**167**	**185**	170	146	126	136	136	122	109	97
CBM	**303**	**309**	303	298	259	283	256	245	251	194
Shallow Gas	**706**	**691**	712	715	726	727	713	729	735	739
Total natural gas[1] (MMcf/d)	**3,135**	**3,244**	3,150	3,015	2,752	2,938	2,808	2,698	2,560	2,422
Oil (Mbbls/d)										
Foster Creek	**25**	**27**	21	27	24	25	26	25	20	18
Christina Lake	**4**	**5**	4	2	3	2	3	3	3	3
Pelican Lake	**22**	**22**	21	24	23	24	24	23	23	24
Weyburn[2]	**14**	**14**	13	14	15	14	15	14	15	15
Total oil (Mbbls/d) [2]	**65**	**68**	59	67	65	65	68	65	61	60
Total (MMcfe/d) [1, 2]	**3,523**	**3,648**	3,506	3,417	3,142	3,328	3,210	3,088	2,926	2,782
% change from prior period		**+4.1**	+2.6	+2.7	+12.9	+3.7	+4.0	+5.5	+9.2	

1 Key resource play production volumes in 2007 and 2006 for Cutbank Ridge and Bighorn were restated in the first quarter of 2008 to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.
2 Total key resource play production volumes in 2007 and 2006 were restated in the first quarter of 2008 to include the designation of Weyburn as a key oil resource play.

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled									
	2008				2007					2006
	YTD	**Q3**	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas										
Jonah	**135**	**43**	49	43	135	23	31	42	39	163
Piceance	**258**	**94**	81	83	286	77	72	72	65	220
East Texas	**55**	**22**	22	11	35	8	9	11	7	59
Fort Worth	**62**	**21**	20	21	75	15	17	29	14	97
Greater Sierra	**92**	**29**	27	36	109	27	27	32	23	115
Cutbank Ridge[1]	**65**	**17**	24	24	93	11	23	26	33	134
Bighorn[1]	**59**	**11**	18	30	62	6	18	10	28	58
CBM	**339**	**78**	10	251	1,079	330	323	18	408	729
Shallow Gas	**812**	**233**	83	496	1,914	649	608	241	416	1,310
Total gas wells[1]	**1,877**	**548**	334	995	3,788	1,146	1,128	481	1,033	2,885
Oil										
Foster Creek	**19**	**6**	1	12	23	6	8	1	8	3
Christina Lake	**-**	**-**	-	-	3	-	1	2	-	1
Pelican Lake	**-**	**-**	-	-	-	-	-	-	-	-
Weyburn[2]	**18**	**4**	5	9	37	10	9	9	9	35
Total oil wells[2]	**37**	**10**	6	21	63	16	18	12	17	39
Total[1,2]	**1,914**	**558**	340	1,016	3,851	1,162	1,146	493	1,050	2,924

1 Key resource play net wells drilled in 2007 and 2006 for Cutbank Ridge and Bighorn were restated in the first quarter of 2008 to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.
2 Total key resource play net wells drilled in 2007 and 2006 were restated in the first quarter of 2008 to include the designation of Weyburn as a key oil resource play.

Third Quarter 2008 natural gas and oil prices

	Q3 2008	Q3 2007	**% Δ**	**9 months 2008**	9 months 2007	**% Δ**
Natural gas ($Mcf)						
NYMEX	**10.24**	6.16	+66	**9.73**	6.83	+42
EnCana Realized Gas Price[1]	**7.94**	6.75	+18	**8.17**	7.19	+14
Oil and NGLs ($/bbl)						
WTI	**118.22**	75.15	+57	**113.52**	66.22	+71
Western Canadian Select (WCS)	**100.22**	52.71	+90	**93.16**	46.86	+99
Differential WTI/WCS	**18.00**	22.44	-20	**20.36**	19.36	+5
EnCana Realized Liquids Price[1]	**90.88**	49.01	+85	**83.49**	45.71	+83
3-2-1 Crack Spread ($/bbl)						
Chicago	**17.29**	18.48	-6	**12.86**	20.50	-37

1 Realized prices include the impact of financial hedging.

Price risk management
Risk management positions at September 30, 2008 are presented in Note 17 to the unaudited Interim Consolidated Financial Statements. In the third quarter of 2008, EnCana's commodity price risk management measures resulted in realized losses of approximately $271 million after tax, comprised of a $203 million after-tax loss on gas hedges, and a $68 million after-tax loss on oil and other hedges. EnCana has hedged about 2.4 Bcf/d of expected 2008 gas production for the balance of the year at an average NYMEX equivalent price of $8.82 per Mcf. EnCana has about 23,000 bbls/d of expected 2008 oil production hedged for the balance of the year under fixed price contracts at an average West Texas Intermediate (WTI) price of $70.13 per bbl. For the calendar year 2009, EnCana has 1.6 Bcf/d of its expected natural gas production under fixed price contracts at an average NYMEX equivalent price of $9.31 per Mcf and 0.5 Bcf/d under NYMEX put options at an average strike price of $9.10 per Mcf.

U.S. Rockies and Canadian basis differential hedges
North American natural gas prices are impacted by volatile pricing disconnects caused primarily by transportation constraints between producing regions and consuming regions. These price discounts are called basis differentials. EnCana has hedged 100 percent of its expected U.S. Rockies basis exposure through 2011 using a combination of downstream transportation and basis hedges, including some hedges that are based on a percentage of NYMEX prices and some hedges that move basis risk to alternative markets downstream. EnCana has also hedged about 6 percent of its expected 2008 Canadian gas production at an average AECO basis differential of 72 cents per Mcf.

Corporate developments

Quarterly dividend of 40 cents per share declared
EnCana's Board of Directors has declared a quarterly dividend of 40 cents per share payable on December 31, 2008 to common shareholders of record as of December 15, 2008. Based on the October 22, 2008 closing share price on the New York Stock Exchange of $41.10, this represents an annualized yield of about 3.9 percent.

EnCana revises schedule for creation of Cenovus Energy Inc.
On October 15, 2008, EnCana announced that it is revising the schedule for its proposed split into two independent energy companies – an integrated oil company to be named Cenovus Energy Inc. and a pure-play natural gas company, which will retain the name EnCana Corporation. The proposed corporate reorganization was expected to close in early January 2009. The transaction is to be implemented through a Plan of Arrangement and is subject to shareholder and court approvals.

"During this period of market uncertainty, we've decided it is in the best interests of shareholders to delay the timing of the reorganization," said Eresman. "We continue to work towards the creation of Cenovus and will be ready to move forward with the transaction at the appropriate time."

Work is underway on a Cenovus logo and brand as well as a new brand for EnCana. For further information on the reorganization, see the company's website www.encana.com.

Normal Course Issuer Bid
As a result of the proposed corporate split, EnCana suspended the purchase of common shares for cancellation. EnCana has no plans to resume purchases while the company continues to move forward with the reorganization.

Brazil sale closes
In September 2008, EnCana completed the sale of its interests in Brazil, which included non-operated interests in 10 offshore exploration blocks. EnCana received net proceeds of $164 million and recorded an after-tax gain of approximately $99 million on the sale.

Financial strength

EnCana maintains a strong balance sheet, targeting a net debt to capitalization ratio between 30 and 40 percent and a net debt to adjusted EBITDA multiple, on a trailing 12-month basis, of 1 to 2 times. At September 30, 2008, EnCana's net debt to capitalization ratio was 26 percent, including mark-to-market gains on risk management instruments, which decreased net debt. Excluding this mark-to-market impact to working capital, the net debt to capitalization ratio would have been 29 percent. EnCana's net debt to adjusted EBITDA multiple, on a trailing 12-month basis, was 0.6 times at the end of the third quarter. The company expects to continue to be in the lower end of its managed ranges through year-end. Upcoming debt maturities are modest as indicated below.

Long-Term Debt maturities through 2010

($ millions)

Issue	Currency	Total
4.6% due August 15, 2009	USD	$250.0
7.65% due September 15, 2010	USD	$200.0

In the third quarter, EnCana invested $1.6 billion in capital, excluding acquisitions and divestitures, on continued development of its key resource plays and expansion of the company's downstream heavy oil processing capacity through its venture with ConocoPhillips. Net acquisitions and divestitures for the first nine months of 2008 were $621 million, including approximately $600 million in divestitures and $1.1 billion in acquisitions in the U.S., largely due to investments in Haynesville properties.

NOTE 1: Non-GAAP measures

This interim report contains references to cash flow, operating earnings, free cash flow, net debt, capitalization and adjusted earnings before interest, tax, depreciation and amortization (EBITDA).

- Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations.
- Operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain/loss on discontinuance, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, the after-tax foreign exchange gain/loss on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only, and the effect of changes in statutory income tax rates. Management believes that these excluded items reduce the comparability of the company's underlying financial performance between periods. The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- Free cash flow is a non-GAAP measure that EnCana defines as cash flow in excess of capital investment, excluding net acquisitions and divestitures, and is used to determine the funds available for other investing and/or financing activities.
- Net debt is a non-GAAP measure defined as long-term debt plus current liabilities less current assets. Capitalization is a non-GAAP measure defined as net debt plus shareholders' equity. Net debt to capitalization and net debt to adjusted EBITDA are two ratios management uses to steward the company's overall debt position as measures of the company's overall financial strength.
- Adjusted EBITDA is a non-GAAP measure defined as net earnings from continuing operations before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

These measures have been described and presented in this interim report in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

EnCana Corporation
With an enterprise value of approximately $40 billion, EnCana is a leading North American unconventional natural gas and integrated oil company. By partnering with employees, community organizations and other businesses, EnCana contributes to the strength and sustainability of the communities where it operates. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

ADVISORY REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION – EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). EnCana's reserves quantities represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

In this interim report, certain crude oil and NGLs volumes have been converted to cubic feet equivalent (cfe) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the same basis. BOE and cfe may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this interim report are forward-looking statements or information within the meaning of applicable securities legislation, collectively referred to herein as "forward-looking statements." Forward-looking statements in this interim report include, but are not limited to: projections relating to future economic and operating performance (including per share growth, net debt to capitalization and net debt to adjusted EBITDA ratios, cash flow, operating cash flow, and cash flow per share); the anticipated ability to meet the company's guidance forecasts; the ability of the company to withstand a volatile pricing environment; anticipated growth and success of various resource plays and the expected characteristics of such resource plays; the future drilling and production potential for various regions, including East Texas and the Horn River and Haynesville natural gas shale plays; projections relating to the proposed corporate reorganization transaction, including the expected timing for proceeding with this transaction; projections of crude oil and natural gas prices, including basis differentials for various regions; anticipated expansion and production at Foster Creek and Christina Lake; the potential success, capacity, cost and timing of the CORE project at Wood River; anticipated continued suspension of purchases under EnCana's normal course issuer bid; the potential timing, cost and success of the Deep Panuke project; anticipated limiting of production at Jonah; projections for future crack spreads and refining margins; anticipated effects of EnCana's market risk mitigation strategy; projections for 2008 capital expenditures and investment; projections for oil, natural gas and NGLs production in 2008 and beyond; anticipated costs and inflationary pressures; and potential divestitures, proceeds which may be generated there from and the potential use of such proceeds.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: risks associated with the timing and the ability to obtain any necessary approvals, waivers, consents, court orders and other requirements necessary or desirable to permit or facilitate the proposed transaction (including, regulatory and shareholder approvals); the risk that any applicable conditions of the proposed transaction may not be satisfied; volatility of and assumptions regarding oil and gas prices; assumptions based upon the company's current guidance; fluctuations in currency and interest rates; product supply and demand; North American and global market conditions including financial markets; market competition; risks inherent in the company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves; the ability of the company and ConocoPhillips to successfully manage and operate the integrated North American oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology; the company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the company operates; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.

Forward-looking information respecting anticipated 2008 cash flow, operating cash flow and pre-tax cash flow for EnCana, EnCana post-arrangement (prior working name GasCo) and Cenovus pro-forma the proposed reorganization transaction, is based upon achieving average production of oil and gas for 2008 as set out in the company's guidance, average commodity prices for 2008 based on actual results for the first three quarters of 2008, and for the balance of 2008, a WTI price of $85/bbl for oil, a NYMEX price of $7.50/Mcf for natural gas, an average U.S./Canadian dollar foreign exchange rate of $0.90, an average Chicago crack spread for 2008 of $9.00/bbl for refining margins, and an average number of outstanding shares for EnCana of approximately 750 million. Forward-looking information respecting the rescheduling of the proposed reorganization transaction is based upon the assumption that financial markets will stabilize. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

Furthermore, the forward-looking statements contained in this interim report are made as of the date of this interim report, and, except as required by law, EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this interim report are expressly qualified by this cautionary statement.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read with the unaudited Interim Consolidated Financial Statements ("Interim Consolidated Financial Statements") for the period ended September 30, 2008, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2007. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document.

The Interim Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This document is dated effective October 22, 2008.

Readers can find the definition of certain terms used in this document in the disclosure regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana contained in the Advisories section located at the end of this document. Except as otherwise noted, all 2008 comparative figures are for the period ended September 30 and are compared to the equivalent prior year period.

EnCana's Business

EnCana is a leading North American unconventional natural gas and integrated oil company.

On May 11, 2008, EnCana announced its plans to split into two independent energy companies - one a North American natural gas company and the other a fully integrated oil company with in-situ oil properties and refineries supplemented by reliable production from various gas and oil resource plays. The proposed corporate reorganization (the "Arrangement"), was expected to close in early January 2009.

Subsequent to September 30, 2008, EnCana announced the proposed Arrangement will be delayed until the global debt and equity markets regain stability. The proposed Arrangement is expected to be implemented through a court approved Plan of Arrangement and is subject to shareholder approval. The reorganization would result in two publicly traded entities with the names of Cenovus Energy Inc. ("Cenovus") (prior working name "IOCo") and EnCana Corporation (prior working name "GasCo"). Each EnCana shareholder would receive one share of each entity in exchange for each EnCana Common Share held. Additional details on the Arrangement are available in the 2008 news releases dated May 11, October 15 and October 23 on our website at www.encana.com.

As a result of the proposed Arrangement, EnCana has changed its reportable segments to reflect the realigned reporting hierarchies. The most significant change results in EnCana now presenting Canadian Plains and Canadian Foothills as separate operating segments. These were previously aggregated and presented in the Canada segment. Prior periods have been restated to reflect the new presentation.

EnCana's operating segments, post-Arrangement, will include Canadian Foothills, United States and Offshore and International. Cenovus' operating segments, post-Arrangement, will include Canadian Plains and Integrated Oil.

EnCana has defined its continuing operations into the following segments:

- **Canadian Plains, Canadian Foothills, United States and Offshore and International** segments include the Company's exploration for, and development and production of natural gas, crude oil and NGLs and other related activities. The majority of the Company's operations are located in Canada and the U.S. The Offshore and International segment is mainly focused on opportunities in Atlantic Canada and Europe.
- **Integrated Oil** is focused on two lines of business: the exploration for, and development and production of bitumen in Canada using in-situ recovery methods; and the refining of crude oil into petroleum and chemical products located in the United States. This segment includes EnCana's 50 percent interest in the joint venture with ConocoPhillips.
- **Market Optimization** is conducted by the Midstream & Marketing division. The Marketing groups' primary responsibility is the sale of the Company's proprietary production. The results are included in the Canadian Plains, Canadian Foothills, United States and Integrated Oil segments. Correspondingly, the Marketing groups also undertake market optimization activities which comprise third-party purchases and sales of product that provide operational flexibility for transportation

commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.

- **Corporate** includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

2008 versus 2007 Results Review

In the third quarter of 2008 compared to the third quarter of 2007, EnCana:

- Increased Cash Flow by 27 percent to $2,809 million;
- Increased Operating Earnings by 40 percent to $1,442 million;
- Reported a 280 percent increase in Net Earnings to $3,553 million primarily due to after-tax unrealized mark-to-market hedging gains of $2,043 million in 2008 compared with losses of $69 million in 2007;
- Increased Free Cash Flow by $578 million to $1,221 million;
- Grew total production 6 percent to 4,718 million cubic feet equivalent ("MMcfe") per day ("MMcfe/d"). On a per share basis, production increased 6 percent;
- Increased production from natural gas key resource plays 16 percent and reported relatively unchanged production from oil key resource plays;
- Reported a $440 million decrease in operating cash flows from Downstream operations;
- Reported a 71 percent increase in natural gas prices, excluding financial hedges, to $8.74 per thousand cubic feet ("Mcf") and a 85 percent increase in liquids prices, excluding financial hedges, to $98.85 per barrel ("bbl"). Realized hedging losses were $271 million after-tax in 2008 compared with gains of $323 million after-tax in 2007; and
- Recorded a decrease in long-term compensation costs as a result of the change in the EnCana share price that reduced reported capital investment by $149 million, operating expense by $111 million and administrative expense by $108 million.

In the nine months of 2008 compared to the nine months of 2007, EnCana:

- Increased Cash Flow by 24 percent to $8,087 million;
- Increased Operating Earnings by 22 percent to $3,956 million;
- Reported a 69 percent increase in Net Earnings to $4,867 million primarily due to after-tax unrealized mark-to-market hedging gains of $1,071 million in 2008 compared with losses of $445 million in 2007;
- Increased Free Cash Flow by $643 million to $2,932 million;
- Grew total production 7 percent to 4,627 MMcfe/d. On a per share basis, production increased 9 percent;
- Increased production from natural gas key resource plays 17 percent and reported relatively unchanged production from oil key resource plays;
- Reported a 49 percent increase in natural gas prices, excluding financial hedges, to $8.78 per Mcf and a 96 percent increase in liquids prices, excluding financial hedges, to $91.72 per bbl. Realized hedging losses were $658 million after-tax in 2008 compared with gains of $777 million after-tax in 2007;
- Reported a $555 million decrease in operating cash flows from Downstream operations;
- Purchased approximately 4.8 million of its Common Shares at an average price of $67.13 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of $326 million in the nine months of 2008;
- Was impacted by a 9 percent increase in the average U.S./Canadian dollar exchange rate that increased reported capital investment by $222 million, operating expense by $73 million, administrative expense by $21 million and Depreciation, Depletion and Amortization ("DD&A") expense by $143 million;
- Increased its quarterly dividends to 40 cents per share for the nine months of 2008 compared to 20 cents per share for the same period in 2007; and
- Reported a Net Debt to Adjusted EBITDA of 0.6x and a Net Debt to Capitalization ratio of 26 percent at September 30, 2008. Excluding, the impact from unrealized mark-to-market gains on risk management instruments, the Net Debt to Capitalization ratio would have been 29 percent.

Business Environment

EnCana's financial results are significantly influenced by fluctuations in commodity prices, which include price differentials, crack spreads and the U.S./Canadian dollar exchange rate. The following table shows select market benchmark prices and foreign exchange rates to assist in understanding EnCana's financial results:

(Average for the period)	Three Months Ended September 30 2008	2008 vs 2007	2007	Nine Months Ended September 30 2008	2008 vs 2007	2007
Natural Gas Price Benchmarks						
AECO *(C$/Mcf)*	**$ 9.24**	**65%**	$ 5.61	**$ 8.58**	**26%**	$ 6.81
NYMEX *($/MMBtu)*	**10.24**	**66%**	6.16	**9.73**	**42%**	6.83
Rockies (Opal) *($/MMBtu)*	**5.88**	**100%**	2.94	**7.15**	**74%**	4.11
Texas (HSC) *($/MMBtu)*	**9.98**	**69%**	5.89	**9.43**	**44%**	6.56
Basis Differential *($/MMBtu)*						
AECO/NYMEX	**1.28**	**52%**	0.84	**1.28**	**80%**	0.71
Rockies/NYMEX	**4.36**	**35%**	3.22	**2.58**	**-5%**	2.71
Texas/NYMEX	**0.26**	**-4%**	0.27	**0.30**	**11%**	0.27
Crude Oil Price Benchmarks						
West Texas Intermediate (WTI) *($/bbl)*	**118.22**	**57%**	75.15	**113.52**	**71%**	66.22
Western Canadian Select (WCS) *($/bbl)*	**100.22**	**90%**	52.71	**93.16**	**99%**	46.86
Differential - WTI/WCS *($/bbl)*	**18.00**	**-20%**	22.44	**20.36**	**5%**	19.36
Refining Margin Benchmark						
Chicago 3-2-1 Crack Spread *($/bbl)* (1)	**17.29**	**-6%**	18.48	**12.86**	**-37%**	20.50
Foreign Exchange						
U.S./Canadian Dollar Exchange Rate	**0.961**	**-**	0.957	**0.982**	**9%**	0.905

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of diesel. 2007 and 2008 values are calculated using Ultra Low Sulphur Diesel.

Consolidated Financial Results

($ millions, except per share amounts)	Nine Months Ended September 2008	2007	2008 Q3	2008 Q2	2008 Q1	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Q4
Total Consolidated										
Cash Flow (1)	**$ 8,087**	$ 6,519	**$ 2,809**	$ 2,889	$ 2,389	$ 1,934	$ 2,218	$ 2,549	$ 1,752	$ 1,761
- per share – diluted	**10.75**	8.49	**3.74**	3.85	3.17	2.56	2.93	3.33	2.25	2.18
Net Earnings	**4,867**	2,877	**3,553**	1,221	93	1,082	934	1,446	497	663
- per share – basic	**6.49**	3.79	**4.74**	1.63	0.12	1.44	1.24	1.91	0.65	0.84
- per share – diluted	**6.47**	3.75	**4.73**	1.63	0.12	1.43	1.24	1.89	0.64	0.82
Operating Earnings (2)	**3,956**	3,251	**1,442**	1,469	1,045	849	1,032	1,369	850	675
- per share – diluted	**5.26**	4.24	**1.92**	1.96	1.39	1.12	1.37	1.79	1.09	0.84
Continuing Operations										
Cash Flow from Continuing Operations (1)	**8,087**	6,519	**2,809**	2,889	2,389	1,934	2,218	2,549	1,752	1,742
Net Earnings from Continuing Operations	**4,867**	2,877	**3,553**	1,221	93	1,007	934	1,446	497	643
- per share – basic	**6.49**	3.79	**4.74**	1.63	0.12	1.34	1.24	1.91	0.65	0.81
- per share – diluted	**6.47**	3.75	**4.73**	1.63	0.12	1.33	1.24	1.89	0.64	0.80
Operating Earnings from Continuing Operations (2)	**3,956**	3,251	**1,442**	1,469	1,045	849	1,032	1,369	850	672
Revenues, Net of Royalties	**23,429**	15,645	**10,766**	7,321	5,342	5,801	5,596	5,613	4,436	3,676

(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are defined under the Cash Flow section of this MD&A.

(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are defined under the Operating Earnings section of this MD&A.

CASH FLOW

Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations. Cash Flow from Continuing Operations is a non-GAAP measure defined as cash flow excluding cash flow from discontinued operations. While cash flow measures are considered non-GAAP, they are commonly used in the oil and gas industry and by EnCana to assist Management and investors in measuring the Company's ability to finance capital programs and meet financial obligations.

Summary of Cash Flow

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2008**	2007	**2008**	2007
Cash From Operating Activities	**$ 3,058**	$ 2,180	**$ 6,812**	$ 6,236
(Add back) deduct:				
Net change in other assets and liabilities	**(19)**	1	**(283)**	5
Net change in non-cash working capital	**268**	(39)	**(992)**	(288)
Cash Flow	**$ 2,809**	$ 2,218	**$ 8,087**	$ 6,519

Three Months Ended September 30, 2008 versus 2007

Cash Flow in the third quarter of 2008 increased $591 million or 27 percent compared to the third quarter of 2007 as a result of:

- Average total liquids prices, excluding financial hedges, increased 85 percent to $98.85 per bbl in 2008 compared to $53.37 per bbl in 2007;
- Average total natural gas prices, excluding financial hedges, increased 71 percent to $8.74 per Mcf in 2008 compared to $5.10 per Mcf in 2007; and
- Natural gas production volumes in 2008 increased 8 percent to 3,917 million cubic feet ("MMcf") of gas per day ("MMcf/d") from 3,630 MMcf/d in 2007.

Cash Flow was reduced by:

- Realized financial natural gas, crude oil and other commodity hedging losses of $271 million after-tax in 2008 compared with gains of $323 million after-tax in 2007;
- Operating cash flows from downstream operations decreased $440 million primarily due to weaker refining margins; and
- Increases in transportation and selling, operating, production and mineral taxes, administrative and interest expenses, net of long-term compensation costs in 2008 compared with 2007.

Nine Months Ended September 30, 2008 versus 2007

Cash Flow in the nine months of 2008 increased $1,568 million or 24 percent compared to the nine months of 2007 as a result of:

- Average total liquids prices, excluding financial hedges, increased 96 percent to $91.72 per bbl in 2008 compared to $46.84 per bbl in 2007;
- Average total natural gas prices, excluding financial hedges, increased 49 percent to $8.78 per Mcf in 2008 compared to $5.91 per Mcf in 2007; and
- Natural gas production volumes in 2008 increased 9 percent to 3,830 MMcf/d from 3,513 MMcf/d in 2007.

Cash Flow was reduced by:

- Realized financial natural gas, crude oil and other commodity hedging losses of $658 million after-tax in 2008 compared with gains of $777 million after-tax in 2007;
- Increases in operating, transportation and selling, production and mineral taxes, administrative and interest expenses, net of long-term compensation costs in 2008 compared with 2007;
- Operating cash flows from downstream operations decreased $555 million primarily due to weaker refining margins; and
- Current tax decreased primarily as a result of the estimated current tax recovery associated with realized commodity hedging mentioned above partially offset by increased operating cash flows from higher price and production levels and a one time tax recovery of $174 million in 2007 for a tax legislative change with no comparable amount in 2008.

NET EARNINGS

Three Months Ended September 30, 2008 versus 2007

EnCana's third quarter 2008 Net Earnings were $2,619 million higher compared to 2007. In addition to the items affecting Cash Flow as detailed previously, significant items affecting Net Earnings were:

- Unrealized mark-to-market hedging gains of $2,043 million after-tax in 2008 compared with losses of $69 million after-tax in 2007;
- A reduction in long-term compensation costs due to the change in the EnCana share price of $227 million in 2008 compared with a reduction of $8 million in 2007;
- A gain of $99 million after-tax from the sale of interests in Brazil in 2008 compared to a gain of $25 million after-tax from the sale of assets in Australia in 2007; and
- DD&A increased $107 million in 2008 compared to 2007 primarily due to the increase in production volumes.

Nine Months Ended September 30, 2008 versus 2007

EnCana's nine months of 2008 Net Earnings were $1,990 million higher compared to 2007. In addition to the items affecting Cash Flow as detailed previously, significant items affecting Net Earnings were:

- Unrealized mark-to-market hedging gains of $1,071 million after-tax in 2008 compared with losses of $445 million after-tax in 2007;
- DD&A increased $497 million in 2008 compared to 2007 primarily due to the increase in production volumes and the higher U.S./Canadian dollar exchange rate; and
- In addition to the impact on the unrealized mark-to-market hedging gains mentioned above, future income taxes increased in 2008 compared to 2007. The increase in future tax includes future tax on unrealized foreign exchange gains in 2008 of $132 million with no comparable amount in 2007 and a one time tax recovery of $57 million in 2007 for tax legislative changes with no comparable amount in 2008.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that adjust Net Earnings and Net Earnings from Continuing Operations by non-operating items that Management believes reduce the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings has been prepared to provide investors with information that is more comparable between periods. Operating Earnings are equal to Operating Earnings from Continuing Operations in the nine months of 2008 and also in the comparative period in 2007.

Summary of Operating Earnings

	Three Months Ended September 30				Nine Months Ended September 30			
	2008		2007		**2008**		2007	
($ millions, except per share amounts)		**Per share (5)**		Per share (5)		**Per share (5)**		Per share (5)
Net Earnings, as reported	**$ 3,553**	**$ 4.73**	$ 934	$ 1.24	**$ 4,867**	**$ 6.47**	$ 2,877	$ 3.75
Add back (losses) and deduct gains:								
Unrealized mark-to-market accounting gain (loss), after-tax	**2,043**	**2.72**	(69)	(0.09)	**1,071**	**1.42**	(445)	(0.58)
Non-operating foreign exchange gain (loss), after-tax (1)	**(31)**	**(0.04)**	(54)	(0.07)	**(259)**	**(0.34)**	(50)	(0.07)
Gain (loss) on discontinuance, after-tax (2)	**99**	**0.13**	25	0.03	**99**	**0.13**	84	0.11
Future tax recovery due to tax rate reductions	**-**	**-**	-	-	**-**	**-**	37	0.05
Operating Earnings (3) (4)	**$ 1,442**	**$ 1.92**	$ 1,032	$ 1.37	**$ 3,956**	**$ 5.26**	$ 3,251	$ 4.24

(1) Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, the partnership contribution receivable, realized foreign exchange gain (loss) on settlement of intercompany transactions, after-tax and future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only. The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.

(2) For third quarter and nine months of 2008, gain on sale of interests in Brazil. For third quarter 2007, gain on sale of Australia assets; for nine months of 2007, gain on sale of Australia assets and interests in Chad.

(3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates. In 2007, EnCana changed its calculation of Operating Earnings to exclude the foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.

(4) Unrealized gains or losses and realized foreign exchange gains or losses on settlement of intercompany transactions have no impact on Cash Flow.

(5) Per Common Share - diluted.

FOREIGN EXCHANGE

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate was relatively unchanged at $0.961 in the third quarter of 2008 compared to $0.957 in the third quarter of 2007 and increased 9 percent to $0.982 in the nine months of 2008 compared to $0.905 in the nine months of 2007. The table below summarizes the impacts of these increases on EnCana's operations when compared to the same periods in 2007.

	Three Months Ended September 30, 2008		Nine Months Ended September 30, 2008	
Average U.S./Canadian Dollar Exchange Rate	**$ 0.961**		**$ 0.982**	
Change from comparative period in 2007	**0.004**		**0.077**	
	$ millions	**$/Mcfe**	**$ millions**	**$/Mcfe**
Increase (decrease) in:				
Capital Investment	**$ 2**		**$ 222**	
Operating Expense	**1**	**-**	**73**	**0.06**
Administrative Expense	**1**	**-**	**21**	**0.02**
DD&A Expense	**2**		**143**	

Additional detail regarding the impact of foreign exchange on EnCana's 2008 results is available in the Corporate Guidance on our website at www.encana.com.

RESULTS OF OPERATIONS

Production Volumes

	Nine Months Ended September 30		2008			2007				2006
	2008	2007	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Produced Gas *(MMcf/d)*										
Canadian Plains	**849**	874	**831**	856	860	876	858	874	891	901
Canadian Foothills	**1,299**	1,236	**1,351**	1,289	1,256	1,313	1,280	1,231	1,196	1,207
United States	**1,618**	1,305	**1,674**	1,629	1,552	1,464	1,387	1,303	1,222	1,201
Integrated Oil - Other[1]	**64**	98	**61**	67	65	69	105	98	91	97
	3,830	3,513	**3,917**	3,841	3,733	3,722	3,630	3,506	3,400	3,406
Crude Oil *(bbls/d)*										
Canadian Plains	**66,549**	71,159	**64,789**	65,097	69,781	70,287	70,711	70,148	72,639	69,567
Canadian Foothills	**8,486**	8,140	**8,217**	8,376	8,867	8,441	7,978	7,959	8,489	8,643
Foster Creek/Christina Lake	**28,542**	26,688	**31,547**	24,671	29,376	27,190	28,740	27,994	23,269	46,678
Integrated Oil - Other[1]	**2,930**	2,568	**2,273**	3,009	3,514	3,040	2,235	2,489	2,990	5,341
	106,507	108,555	**106,826**	101,153	111,538	108,958	109,664	108,590	107,387	130,229
NGLs *(bbls/d)*										
Canadian Plains	**1,199**	1,206	**1,147**	1,189	1,262	1,422	1,209	1,206	1,203	1,397
Canadian Foothills	**11,588**	9,748	**11,730**	11,779	11,256	10,966	9,932	9,811	9,497	10,459
United States	**13,524**	13,976	**13,853**	13,482	13,232	14,791	15,578	13,809	12,503	12,584
	26,311	24,930	**26,730**	26,450	25,750	27,179	26,719	24,826	23,203	24,440
Total *(MMcfe/d)* [2]	**4,627**	4,314	**4,718**	4,607	4,557	4,539	4,448	4,306	4,184	4,334

(1) Volumes related to operating areas outside of Foster Creek and Christina Lake including Athabasca (gas) and Senlac (crude oil).
(2) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

Key Resource Plays

	Three Months Ended September 30					Nine Months Ended September 30				
	Daily Production			Drilling Activity (net wells drilled)		Daily Production			Drilling Activity (net wells drilled)	
	2008	**2008 vs 2007**	2007	**2008**	2007	**2008**	**2008 vs 2007**	2007	**2008**	2007
Natural Gas *(MMcf/d)*										
Jonah	**615**	**5%**	588	**43**	31	**613**	**14%**	539	**135**	112
Piceance	**407**	**15%**	354	**94**	72	**387**	**12%**	346	**258**	209
East Texas	**339**	**135%**	144	**22**	9	**309**	**140%**	129	**55**	27
Fort Worth	**148**	**16%**	128	**21**	17	**142**	**19%**	119	**62**	60
Greater Sierra	**228**	**4%**	220	**29**	27	**217**	**4%**	208	**92**	82
Cutbank Ridge[1]	**322**	**20%**	269	**17**	23	**291**	**16%**	250	**65**	82
Bighorn[1]	**185**	**36%**	136	**11**	18	**167**	**37%**	122	**59**	56
CBM	**309**	**21%**	256	**78**	323	**303**	**21%**	251	**339**	749
Shallow Gas	**691**	**-3%**	713	**233**	608	**706**	**-3%**	725	**812**	1,265
	3,244	**16%**	2,808	**548**	1,128	**3,135**	**17%**	2,689	**1,877**	2,642
Oil *(bbls/d)*										
Foster Creek	**26,979**	**3%**	26,243	**6**	8	**24,936**	**4%**	24,059	**19**	17
Christina Lake	**4,568**	**83%**	2,497	**-**	1	**3,606**	**37%**	2,629	**-**	3
	31,547	**10%**	28,740	**6**	9	**28,542**	**7%**	26,688	**19**	20
Pelican Lake	**22,196**	**-6%**	23,617	**-**	-	**22,510**	**-2%**	23,086	**-**	-
Weyburn	**13,590**	**-10%**	15,032	**4**	9	**13,583**	**-9%**	15,009	**18**	27
	67,333	**-**	67,389	**10**	18	**64,635**	**-**	64,783	**37**	47
Total *(MMcfe/d)* [2]	**3,648**	**14%**	3,210	**558**	1,146	**3,523**	**15%**	3,076	**1,914**	2,689

(1) Key resource play production and wells drilled information in 2007 for Cutbank Ridge and Bighorn were restated in the first quarter of 2008 to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.
(2) Total key resource play production and wells drilled information in 2007 was restated in the first quarter of 2008 to include the designation of Weyburn as an oil key resource play.

Production volumes increased 6 percent or 270 MMcfe/d in the third quarter of 2008 compared to the third quarter of 2007 and 7 percent or 313 MMcfe/d in the nine months of 2008 compared to the nine months of 2007 due to increased production from EnCana's natural gas key resource plays of 16 percent and 17 percent, respectively, offset partially by natural declines in conventional properties.

ENCANA POST-ARRANGEMENT OPERATING SEGMENTS

As discussed in the EnCana's Business section of this MD&A, the Company announced its plans to split into two highly focused energy companies. EnCana's operating segments, post-Arrangement, will include Canadian Foothills and United States.

CANADIAN FOOTHILLS AND UNITED STATES

Produced Gas

Three Months Ended September 30, 2008 versus 2007

Financial Results

($ millions, except per unit amounts in $ per thousand cubic feet)

2008	**Canadian Foothills**	**$/Mcf**	**United States**	**$/Mcf**
Revenues, Net of Royalties / Price	**$ 1,123**	**$ 9.03**	**$ 1,315**	**$ 8.54**
Realized Financial Hedging Gain (Loss)	**(141)**		**(52)**	
Expenses				
Production and mineral taxes	**12**	**0.09**	**86**	**0.56**
Transportation and selling	**54**	**0.43**	**132**	**0.86**
Operating	**108**	**0.87**	**59**	**0.38**
Operating Cash Flow / Netback [(1)]	**$ 808**	**$ 7.64**	**$ 986**	**$ 6.74**
Netback including Realized Financial Hedging		**$ 6.51**		**$ 6.40**
Gas Production Volumes *(MMcf/d)*		**1,351**		**1,674**

2007	Canadian Foothills	$/Mcf	United States	$/Mcf
Revenues, Net of Royalties / Price	$ 643	$ 5.46	$ 598	$ 4.68
Realized Financial Hedging Gain (Loss)	122		336	
Expenses				
Production and mineral taxes	9	0.08	49	0.38
Transportation and selling	48	0.41	77	0.60
Operating	114	0.96	68	0.52
Operating Cash Flow / Netback [(1)]	$ 594	$ 4.01	$ 740	$ 3.18
Netback including Realized Financial Hedging		$ 5.04		$ 5.82
Gas Production Volumes *(MMcf/d)*		1,280		1,387

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price[(1)]	Volume	**2008 Revenues Net of Royalties**
Canadian Foothills	$ 765	$ 165	$ 52	**$ 982**
United States	934	112	217	**1,263**
Total Produced Gas	$ 1,699	$ 277	$ 269	**$ 2,245**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, for Canadian Foothills and the U.S. increased in the third quarter of 2008 compared with the same period in 2007 due to:

- A 82 percent increase in U.S. natural gas prices and a 65 percent increase in Canadian Foothills natural gas prices, excluding the impact of financial hedging; and
- A 21 percent increase in U.S. natural gas production volumes and a 6 percent increase in Canadian Foothills natural gas production volumes;

offset by:

- Canadian Foothills realized financial hedging losses of $141 million or $1.13 per Mcf in 2008 compared to gains of $122 million or $1.03 per Mcf in 2007 and U.S. realized financial hedging losses of $52 million or $0.34 per Mcf in 2008 compared to gains of $336 million or $2.64 per Mcf in 2007.

Produced gas volumes in the U.S. increased in 2008 as a result of drilling and operational success at East Texas, Piceance, Jonah and Fort Worth as well as incremental volumes from the Deep Bossier acquisition and upgrades to the compression and gathering facilities at Jonah. Produced gas volumes in the Canadian Foothills increased in 2008 as a result of drilling success and new facilities in the key resource plays of Coalbed Methane ("CBM"), Cutbank Ridge and Bighorn offset partially by natural declines for conventional properties.

The increase in U.S. and Canadian Foothills natural gas prices in 2008, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit production and mineral taxes in the U.S. increased 47 percent or $0.18 per Mcf in 2008 compared to 2007 primarily as a result of higher natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased 43 percent or $0.26 per Mcf in 2008 compared to 2007 as a result of higher unutilized transportation commitments, higher gathering costs and transporting gas greater distances on the Rockies Express Pipeline to improve price realizations.

Natural gas per unit operating expenses in the U.S. in 2008 were 27 percent or $0.14 per Mcf lower than in 2007 primarily due to lower long-term compensation costs due to the change in the EnCana share price and a high proportion of fixed costs spread over increased production volumes offset by higher salaries and benefits and repairs and maintenance expenses. Natural gas per unit operating expenses for the Canadian Foothills in 2008 were 9 percent or $0.09 per Mcf lower than in 2007 primarily as a result of lower long-term compensation costs offset by increased gas gathering and processing, repairs and maintenance, salaries and benefits expenses and property tax and lease costs.

Nine Months Ended September 30, 2008 versus 2007

Financial Results

($ millions, except per unit amounts in $ per thousand cubic feet)

2008

	Canadian Foothills				United States			
				$/Mcf				$/Mcf
Revenues, Net of Royalties / Price	$	3,159	$	8.88	$	3,945	$	8.89
Realized Financial Hedging Gain (Loss)		(268)				(191)		
Expenses								
Production and mineral taxes		26		0.07		280		0.63
Transportation and selling		158		0.44		367		0.83
Operating		432		1.21		266		0.60
Operating Cash Flow / Netback (1)	$	2,275	$	7.16	$	2,841	$	6.83
Netback including Realized Financial Hedging			$	6.41			$	6.40
Gas Production Volumes *(MMcf/d)*				1,299				1,618

2007

	Canadian Foothills				United States			
				$/Mcf				$/Mcf
Revenues, Net of Royalties / Price	$	2,107	$	6.24	$	1,964	$	5.51
Realized Financial Hedging Gain (Loss)		245				790		
Expenses								
Production and mineral taxes		32		0.10		127		0.36
Transportation and selling		142		0.42		220		0.62
Operating		345		1.02		228		0.63
Operating Cash Flow / Netback (1)	$	1,833	$	4.70	$	2,179	$	3.90
Netback including Realized Financial Hedging			$	5.43			$	6.12
Gas Production Volumes *(MMcf/d)*				1,236				1,305

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

($ millions)	2007 Revenues Net of Royalties		Revenue Variances in: Price(1)		Volume		**2008 Revenues Net of Royalties**	
Canadian Foothills	$	2,352	$	389	$	150	**$**	**2,891**
United States		2,754		263		737		**3,754**
Total Produced Gas	$	5,106	$	652	$	887	**$**	**6,645**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, for Canadian Foothills and the U.S. increased in the nine months of 2008 compared with the same period in 2007 due to:

- A 61 percent increase in U.S. natural gas prices and a 42 percent increase in Canadian Foothills natural gas prices, excluding the impact of financial hedging; and
- A 24 percent increase in U.S. natural gas production volumes and a 5 percent increase in Canadian Foothills natural gas production volumes;

offset by:

- Canadian Foothills realized financial hedging losses of $268 million or $0.75 per Mcf in 2008 compared to gains of $245 million or $0.73 per Mcf in 2007 and U.S. realized financial hedging losses of $191 million or $0.43 per Mcf in 2008 compared to gains of $790 million or $2.22 per Mcf in 2007.

Produced gas volumes in the U.S. increased in 2008 as a result of drilling and operational success at East Texas, Jonah, Piceance and Fort Worth as well as incremental volumes from the Deep Bossier acquisition and upgrades to the compression and gathering facilities at Jonah. Produced gas volumes in the Canadian Foothills increased in 2008 as a result of drilling success and new facilities in the key resource plays of CBM, Bighorn and Cutbank Ridge offset partially by natural declines for conventional properties.

The increase in U.S. and Canadian Foothills natural gas prices in 2008, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit production and mineral taxes in the U.S. increased 75 percent or $0.27 per Mcf in 2008 compared to 2007 primarily as a result of higher natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased 34 percent or $0.21 per Mcf in 2008 compared to 2007 as a result of transporting gas greater distances on the Rockies Express Pipeline to improve price realizations and higher unutilized transportation commitments.

Natural gas per unit operating expenses for the Canadian Foothills in 2008 were 19 percent or $0.19 per Mcf higher than in 2007 primarily as a result of the higher U.S./Canadian dollar exchange rate, higher repairs and maintenance due to planned plant turnarounds, increased gathering and processing and salaries and benefits expenses offset by lower long-term compensation costs due to the change in the EnCana share price. Natural gas per unit operating expenses for the U.S. were impacted by a high proportion of fixed costs spread over increased production volumes and lower long-term compensation costs offset by increased salaries and benefits, repairs and maintenance and workovers costs.

Crude Oil and NGLs

Three Months Ended September 30, 2008 versus 2007

Financial Results

($ millions)	**2008**		2007	
	Canadian Foothills	**United States**	Canadian Foothills	United States
Revenues, Net of Royalties	**$ 172**	**$ 124**	$ 100	$ 86
Expenses				
Production and mineral taxes	**2**	**11**	1	3
Transportation and selling	**3**	**-**	3	-
Operating	**7**	**-**	9	-
Operating Cash Flow	**$ 160**	**$ 113**	$ 87	$ 83

Crude Oil and NGLs Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
Canadian Foothills	$ 100	$ 56	$ 16	**$ 172**
United States	86	53	(15)	**124**
Total Crude Oil and NGLs	$ 186	$ 109	$ 1	**$ 296**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, for Canadian Foothills and the U.S. increased in the third quarter of 2008 compared with the same period in 2007 due to:

- A 68 percent increase in Canadian Foothills crude oil prices and 58 percent increase in North American NGLs prices, excluding financial hedges;

offset by:

- Canadian Foothills realized financial hedging losses on liquids of $17 million or $9.20 per bbl in 2008 compared to losses of $8 million or $4.73 per bbl in 2007.

Per Unit Results – Crude Oil

($ per barrel)	Canadian Foothills	
	2008	2007
Price (1)	**$ 112.73**	$ 67.07
Expenses		
Production and mineral taxes	**1.65**	0.76
Transportation and selling	**2.12**	2.16
Operating	**10.02**	11.21
Netback	**$ 98.94**	$ 52.94
Crude Oil Production Volumes *(bbls/d)*	**8,217**	7,978

(1) Excludes the impact of realized financial hedging.

Canadian Foothills crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were approximately $7 million or $9.53 per bbl in 2008 compared to losses of approximately $4 million or $4.68 per bbl in 2007.

Canadian Foothills crude oil per unit production and mineral taxes increased 117 percent or $0.89 per bbl in 2008 compared to 2007 primarily due to higher crude oil prices.

Canadian Foothills crude oil per unit operating costs in 2008 decreased 11 percent or $1.19 per bbl compared to 2007 mainly due to decreased workovers, repairs and maintenance and salaries and benefits expenses offset by higher electricity costs.

Per Unit Results – NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas. NGLs production volumes from the U.S. were 13,853 bbls/d in 2008 compared to 15,578 bbls/d in 2007 and from Canadian Foothills were 11,730 bbls/d in 2008 compared to 9,932 bbls/d in 2007. Average U.S. NGLs realized prices increased 62 percent to $97.63 per bbl in 2008 from $60.17 per bbl in 2007 and average Canadian Foothills NGLs realized prices increased 51 percent to $95.49 per bbl in 2008 from $63.06 per bbl in 2007, which are consistent with the higher WTI benchmark price.

Nine Months Ended September 30, 2008 versus 2007

Financial Results

($ millions)	2008		2007	
	Canadian Foothills	**United States**	Canadian Foothills	United States
Revenues, Net of Royalties	**$ 494**	**$ 353**	$ 268	$ 210
Expenses				
Production and mineral taxes	**4**	**31**	2	15
Transportation and selling	**9**	**-**	7	-
Operating	**30**	**-**	23	-
Operating Cash Flow	**$ 451**	**$ 322**	$ 236	$ 195

Crude Oil and NGLs Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
Canadian Foothills	$ 268	$ 172	$ 54	**$ 494**
United States	210	153	(10)	**353**
Total Crude Oil and NGLs	$ 478	$ 325	$ 44	**$ 847**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, for Canadian Foothills and the U.S. increased in the nine months of 2008 compared with the same period in 2007 due to:

- A 81 percent increase in Canadian Foothills crude oil prices and 73 percent increase in North American NGLs prices, excluding financial hedges;

offset by:

- Canadian Foothills realized financial hedging losses on liquids of $48 million or $8.70 per bbl in 2008 compared to losses of $7 million or $1.35 per bbl in 2007.

Per Unit Results – Crude Oil

($ per barrel)	Canadian Foothills **2008**	2007
Price (1)	**$ 106.53**	$ 58.79
Expenses		
Production and mineral taxes	**1.61**	0.86
Transportation and selling	**2.24**	1.81
Operating	**13.10**	10.19
Netback	**$ 89.58**	$ 45.93
Crude Oil Production Volumes *(bbls/d)*	**8,486**	8,140

(1) Excludes the impact of realized financial hedging.

Canadian Foothills crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices offset by higher average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were approximately $20 million or $8.61 per bbl in 2008 compared to losses of approximately $3 million or $1.32 per bbl in 2007.

Canadian Foothills crude oil per unit production and mineral taxes increased 87 percent or $0.75 per bbl in 2008 compared to 2007 primarily due to higher crude oil prices and the higher U.S./Canadian dollar exchange rate.

Canadian Foothills crude oil per unit transportation and selling costs increased 24 percent or $0.43 per bbl in 2008 compared to 2007 due to increased pipeline tariff rates and the higher U.S./Canadian dollar exchange rate.

Canadian Foothills crude oil per unit operating costs in 2008 increased 29 percent or $2.91 per bbl compared to 2007 mainly due to the higher U.S./Canadian dollar exchange rate, increased electricity costs and gathering and processing costs.

Per Unit Results – NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas. NGLs production volumes from the U.S. were 13,524 bbls/d in 2008 compared to 13,976 bbls/d in 2007 and from Canadian Foothills were 11,588 bbls/d in 2008 compared to 9,748 bbls/d in 2007. Average U.S. NGLs realized prices increased 73 percent to $95.35 per bbl in 2008 from $54.96 per bbl in 2007 and average Canadian Foothills NGLs realized prices increased 72 percent to $92.69 per bbl in 2008 from $53.89 per bbl in 2007, which are consistent with the higher WTI benchmark price.

CENOVUS POST-ARRANGEMENT OPERATING SEGMENTS

As discussed in the EnCana's Business section of this MD&A, the Company announced its plans to split into two highly focused energy companies. Cenovus' operating segments, post-Arrangement, will include Integrated Oil and Canadian Plains.

INTEGRATED OIL

Foster Creek/Christina Lake Operations

On January 2, 2007, EnCana became a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes contributed assets from EnCana, primarily the Foster Creek and Christina Lake oil properties while the downstream entity includes ConocoPhillips' Wood River and Borger refineries located in Illinois and Texas, respectively.

The goal of the upstream business is to increase production capacity at Foster Creek/Christina Lake to approximately 400,000 bbls/d of bitumen (on a 100 percent basis before royalties) by 2016.

Three Months Ended September 30, 2008 versus 2007

Financial Results

($ millions)	Foster Creek/Christina Lake	
	2008	2007
Revenues, Net of Royalties	**$ 362**	$ 160
Expenses		
Transportation and selling	**137**	62
Operating	**42**	35
Operating Cash Flow	**$ 183**	$ 63

Crude Oil Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	Other(2)	**2008 Revenues Net of Royalties**
Foster Creek/ Christina Lake	$ 160	$ 127	$ -	$ 75	**$ 362**

(1) Includes the impact of realized financial hedging.
(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and selling expense.

Revenues, net of royalties, increased in the third quarter of 2008 compared with the same period in 2007 due to:

- A 113 percent increase in crude oil prices, excluding financial hedges; and
- Relatively unchanged crude oil sales volumes attributable to a 10 percent increase in production volumes offset by changes in inventory;

offset by:

- Realized financial hedging losses of $21 million or $7.66 per bbl in 2008 compared to losses of $16 million or $5.81 per bbl in 2007.

Per Unit Results – Crude Oil

($ per barrel)	Foster Creek/Christina Lake	
	2008	2007
Price [1][2]	**$ 91.21**	$ 42.86
Expenses		
Transportation and selling	**2.10**	2.10
Operating	**15.53**	12.55
Netback	**$ 73.58**	$ 28.21
Crude Oil Production Volumes *(bbls/d)*	**31,547**	28,740

(1) Excludes the impact of realized financial hedging.
(2) Represents blended sales price net of purchased condensate costs.

Foster Creek/Christina Lake crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices compared to 2007 as well as lower price differentials. WCS as a percentage of WTI was 85 percent in 2008 compared to 70 percent in 2007.

Foster Creek/Christina Lake crude oil per unit operating costs increased 24 percent or $2.98 per bbl in 2008 compared to 2007. The increase is mainly due to increased purchased fuel costs, staff levels and workovers offset by lower long-term compensation costs due to the change in the EnCana share price.

Nine Months Ended September 30, 2008 versus 2007

Financial Results

($ millions)	Foster Creek/Christina Lake	
	2008	2007
Revenues, Net of Royalties	**$ 898**	$ 552
Expenses		
Transportation and selling	**380**	258
Operating	**133**	123
Operating Cash Flow	**$ 385**	$ 171

Crude Oil Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price[1]	Volume	Other[2]	**2008 Revenues Net of Royalties**
Foster Creek/ Christina Lake	$ 552	$ 281	$ (62)	$ 127	**$ 898**

(1) Includes the impact of realized financial hedging.
(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and selling expense.

Revenues, net of royalties, increased in the nine months of 2008 compared with the same period in 2007 due to:

- A 112 percent increase in crude oil prices, excluding financial hedges;

offset by:

- Realized financial hedging losses of $79 million or $10.47 per bbl in 2008 compared to losses of $10 million or $1.15 per bbl in 2007; and
- Lower crude oil sales volumes attributable to the planned turnaround at Foster Creek in the second quarter of 2008 and changes in inventory.

Per Unit Results – Crude Oil

($ per barrel)	Foster Creek/Christina Lake	
	2008	2007
Price (1)(2)	**$ 81.64**	$ 38.45
Expenses		
Transportation and selling	**2.51**	2.92
Operating	**17.69**	14.59
Netback	**$ 61.44**	$ 20.94
Crude Oil Production Volumes *(bbls/d)*	**28,542**	26,688

(1) Excludes the impact of realized financial hedging.

(2) Represents blended sales price net of purchased condensate costs.

Foster Creek/Christina Lake crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices compared to 2007 as well as price differentials not increasing as much as benchmark prices. WCS as a percentage of WTI was 82 percent in 2008 compared to 71 percent in 2007.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2008 decreased 14 percent or $0.41 per bbl compared to 2007 due to variability in sales destinations and pipelines utilized to transport the bitumen volumes, offset partially by the higher U.S./Canadian dollar exchange rate.

Foster Creek/Christina Lake crude oil per unit operating costs increased 21 percent or $3.10 per bbl in 2008 compared to 2007. The increase is mainly due to increased purchased fuel costs, staff levels and workovers. In addition, operating costs for 2008 compared to 2007 were impacted by the higher U.S./Canadian dollar exchange rate.

Downstream Operations

Financial Results

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2008**	2007	**2008**	2007
Revenues	**$ 2,699**	$ 2,049	**$ 7,514**	$ 5,109
Expenses				
Operating	**116**	98	**375**	317
Purchased product	**2,679**	1,607	**6,800**	3,898
Operating Cash Flow	**$ (96)**	$ 344	**$ 339**	$ 894

The downstream business commenced on January 2, 2007 when EnCana became a 50 percent partner in the entity that owns the Wood River and Borger refineries operated by ConocoPhillips.

The Wood River refinery, located in Roxana, Illinois, has a current capacity of approximately 306,000 bbls/d of crude oil (on a 100 percent basis). In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the Coker and Refinery Expansion ("CORE") project. EnCana's 50 percent share of the CORE project is expected to cost approximately $1.8 billion and is anticipated to be completed and in full operation in 2011. The expansion will increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and will more than double heavy crude oil refining capacity to 240,000 bbls/d.

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 bbls/d of crude oil and approximately 45,000 bbls/d of NGLs (on a 100 percent basis). The coker installed in 2007 is enabling the refinery to upgrade approximately 35,000 bbls/d of Western Canadian Select heavy crude.

The goal of the downstream business is to refine in the aggregate at the Wood River and Borger refineries approximately 240,000 bbls/d of bitumen (on a 100 percent basis) by 2016 to primarily transportation fuels. Currently, the refineries have processing capability to refine up to approximately 70,000 bbls/d of bitumen (on a 100 percent basis).

Revenues reflect EnCana's 50 percent share of the sale of refined petroleum products in the U.S. Operating Cash Flow during 2008 was impacted by weaker refining margins as evidenced by the Chicago 3-2-1 Crack Spread, which is disclosed in the Business Environment section of this MD&A. The Chicago 3-2-1 Crack Spread decreased 6 percent to $17.29 per bbl in the third quarter of 2008 compared to $18.48 per bbl in 2007 and decreased 37 percent to $12.86 per bbl in the nine months of 2008 compared to $20.50

per bbl in 2007. On a 100 percent basis, the two refineries have a combined crude oil refining capacity of 452,000 bbls/d and operated at an average 91 percent of that capacity during the third quarter of 2008 compared to 102 percent in 2007 and 93 percent during the nine months of 2008 compared to 95 percent in 2007. Refinery crude utilization was lower in the third quarter of 2008 primarily due to unplanned refinery outages and maintenance activities at Wood River as well as crude oil supply disruptions resulting from hurricane activity in the Gulf Coast. Refined products averaged 438,000 bbls/d (219,000 bbls/d net to EnCana) in the third quarter of 2008 compared to 484,000 bbls/d (242,000 bbls/d net to EnCana) in 2007 and 446,000 bbls/d (223,000 bbls/d net to EnCana) in the nine months of 2008 compared to 454,000 bbls/d (227,000 bbls/d net to EnCana) in 2007.

During the third quarter of 2008 EnCana operated in an environment of falling input costs resulting in lower inventory values at the end of the period and higher purchased product costs for the period as the higher priced product inventory was processed and sold. From January 2007 through to July 2008 we experienced an environment of rising input costs which resulted in lower costs for purchased product during the period and higher ending inventory values translating into higher operating cash flow for each reporting period up to June 30, 2008. The effect on Operating Cash Flow during the third quarter of 2008 is a decrease of $95 million (2007 – increase of $72 million) and for year-to-date is an increase of $143 million (2007 – increase of $127 million).

Purchased products, consisting mainly of crude oil, represented 96 percent of total expenses in the third quarter of 2008 compared to 94 percent in 2007 and 95 percent of total expenses in the nine months of 2008 compared to 92 percent in 2007. Operating costs for labour, utilities and supplies comprised the balance of expenses. Revenues and purchased product have increased 32 percent and 67 percent in the quarter, respectively, in line with the significant increase in crude oil prices and reduced refining margins.

Other Integrated Oil Operations

In addition to the 50 percent owned Foster Creek/Christina Lake operations, Integrated Oil also manages the 100 percent owned natural gas operations in Athabasca and crude oil operations in Senlac. Production volumes from Athabasca were 61 MMcf/d in the third quarter of 2008 compared to 105 MMcf/d in the third quarter of 2007 and 64 MMcf/d in the nine months of 2008 compared to 98 MMcf/d in the nine months of 2007. These decreases are due to expected natural declines. Production volumes from Senlac were 2,273 bbls/d in the third quarter of 2008 compared to 2,235 bbls/d in the third quarter of 2007 and 2,930 bbls/d in the nine months of 2008 compared to 2,568 bbls/d in the nine months of 2007.

CANADIAN PLAINS

Produced Gas

Three Months Ended September 30, 2008 versus 2007

Financial Results

($ millions, except per unit amounts in $ per thousand cubic feet) **Canadian Plains**

	2008	**2008 $/Mcf**	2007	2007 $/Mcf
Revenues, Net of Royalties / Price	**$ 663**	**$ 8.67**	$ 416	$ 5.26
Realized Financial Hedging Gain (Loss)	**(87)**		82	
Expenses				
Production and mineral taxes	**14**	**0.17**	11	0.13
Transportation and selling	**18**	**0.24**	18	0.25
Operating	**44**	**0.59**	49	0.62
Operating Cash Flow / Netback (1)	**$ 500**	**$ 7.67**	$ 420	$ 4.26
Netback including Realized Financial Hedging		**$ 6.53**		$ 5.30
Gas Production Volumes *(MMcf/d)*		**831**		858

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price[1]	Revenue Variances in: Volume	**2008 Revenues Net of Royalties**
Canadian Plains	$ 498	$ 97	$ (19)	**$ 576**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, increased in the third quarter of 2008 compared with the same period in 2007 due to:

- A 65 percent increase in natural gas prices, excluding the impact of financial hedging;

offset by:

- Realized financial hedging losses of $87 million or $1.14 per Mcf in 2008 compared to gains of $82 million or $1.04 per Mcf in 2007; and
- A 3 percent decrease in natural gas production volumes. Production added as a result of infill drilling programs was offset by expected natural declines for the Shallow Gas key resource play and conventional properties.

The increase in EnCana's natural gas price in 2008, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit production and mineral taxes for the Canadian Plains in 2008 were 31 percent or $0.04 per Mcf higher than in 2007 primarily due to higher natural gas prices.

Natural gas per unit operating expenses for the Canadian Plains in 2008 were 5 percent or $0.03 per Mcf lower than in 2007 primarily as a result of lower long-term compensation costs due to the change in the EnCana share price offset by higher costs for property tax and lease rentals, electricity and salaries and benefits.

Nine Months Ended September 30, 2008 versus 2007

Financial Results

($ millions, except per unit amounts in $ per thousand cubic feet) **Canadian Plains**

	2008	**2008 $/Mcf**	2007	2007 $/Mcf
Revenues, Net of Royalties / Price	**$ 1,966**	**$ 8.45**	$ 1,446	$ 6.06
Realized Financial Hedging Gain (Loss)	**(171)**		173	
Expenses				
Production and mineral taxes	**32**	**0.14**	31	0.13
Transportation and selling	**55**	**0.24**	61	0.26
Operating	**191**	**0.82**	156	0.65
Operating Cash Flow / Netback [1]	**$ 1,517**	**$ 7.25**	$ 1,371	$ 5.02
Netback including Realized Financial Hedging		**$ 6.52**		$ 5.74
Gas Production Volumes *(MMcf/d)*		**849**		874

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
Canadian Plains	$ 1,619	$ 222	$ (46)	**$ 1,795**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, increased in the nine months of 2008 compared with the same period in 2007 due to:

- A 39 percent increase in natural gas prices, excluding the impact of financial hedging;

offset by:

- Realized financial hedging losses of $171 million or $0.73 per Mcf in 2008 compared to gains of $173 million or $0.72 per Mcf in 2007; and
- A 3 percent decrease in natural gas production volumes. Production added as a result of infill drilling programs was offset by expected natural declines for the Shallow Gas key resource play and conventional properties.

The increase in EnCana's natural gas price in 2008, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit operating expenses for the Canadian Plains in 2008 were 26 percent or $0.17 per Mcf higher than in 2007 primarily as a result of the higher U.S./Canadian dollar exchange rate, higher repairs and maintenance, property tax and lease costs and salaries and benefits expenses.

Crude Oil and NGLs

Three Months Ended September 30, 2008 versus 2007

Financial Results

($ millions)	Canadian Plains **2008**	Canadian Plains 2007
Revenues, Net of Royalties	**$ 559**	$ 323
Expenses		
Production and mineral taxes	**13**	6
Transportation and selling	**14**	8
Operating	**51**	53
Operating Cash Flow	**$ 481**	$ 256

Crude Oil and NGLs Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
Canadian Plains	$ 323	$ 289	$ (53)	**$ 559**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, increased in the third quarter of 2008 compared with the same period in 2007 due to:

- A 89 percent increase in crude oil prices and 60 percent increase in NGLs prices, excluding financial hedges;

offset by:

- Realized financial hedging losses on liquids of $56 million or $9.28 per bbl in 2008 compared to losses of $31 million or $4.73 per bbl in 2007.

Production from the Pelican Lake key resource play in the third quarter of 2008 was 22,196 bbls/d, down 6 percent compared to 2007 mainly due to facility down time during the quarter. Production from the Weyburn key resource play of 13,590 bbls/d was down 10 percent mainly due to expected natural declines offset by production adds from the infill drilling program. At Suffield, production of 12,468 bbls/d was down 17 percent mainly due to natural declines and the impact of delayed well tie-ins. Canadian Plains crude oil production was also impacted by higher royalties in 2008. Overall, Canadian Plains crude oil production decreased 8 percent.

Per Unit Results – Crude Oil

($ per barrel)	Canadian Plains	
	2008	2007
Price [1]	**$ 101.33**	$ 53.50
Expenses		
Production and mineral taxes	**2.23**	1.03
Transportation and selling	**1.95**	1.37
Operating	**8.45**	8.00
Netback	**$ 88.70**	$ 43.10
Crude Oil Production Volumes *(bbls/d)*	**64,789**	70,711

(1) Excludes the impact of realized financial hedging.

Canadian Plains crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices. Total realized financial hedging losses on crude oil for Canadian Plains were approximately $55 million or $9.27 per bbl in 2008 compared to losses of approximately $31 million or $4.74 per bbl in 2007.

Canadian Plains crude oil per unit production and mineral taxes increased 117 percent or $1.20 per bbl in 2008 compared to 2007 primarily due to higher crude oil prices.

Canadian Plains crude oil per unit transportation and selling costs increased 42 percent or $0.58 per bbl in 2008 compared to 2007 due to additional clean oil trucking costs at Pelican Lake combined with lower overall crude oil volumes offset by lower clean oil trucking costs at Weyburn.

Canadian Plains crude oil per unit operating costs in 2008 increased 6 percent or $0.45 per bbl compared to 2007 mainly due to increased chemical costs and property tax and lease costs combined with lower overall crude oil volumes offset by lower long-term compensation costs due to the change in the EnCana share price.

Per Unit Results – NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas. NGLs production volumes were 1,147 bbls/d in 2008 compared to 1,209 bbls/d in 2007. NGLs realized prices increased 60 percent to $98.35 per bbl in 2008 from $61.29 per bbl in 2007, which is consistent with the higher WTI benchmark price.

Nine Months Ended September 30, 2008 versus 2007

Financial Results

($ millions)	Canadian Plains	
	2008	2007
Revenues, Net of Royalties	**$ 1,580**	$ 896
Expenses		
Production and mineral taxes	**32**	21
Transportation and selling	**29**	23
Operating	**191**	153
Operating Cash Flow	**$ 1,328**	$ 699

Crude Oil and NGLs Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price (1)	Volume	**2008 Revenues Net of Royalties**
Canadian Plains	$ 896	$ 772	$ (88)	**$ 1,580**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, increased in the nine months of 2008 compared with the same period in 2007 due to:

- A 100 percent increase in crude oil prices and 64 percent increase in NGLs prices, excluding financial hedges;

offset by:

- Realized financial hedging losses on liquids of $163 million or $8.71 per bbl in 2008 compared to losses of $26 million or $1.33 per bbl in 2007.

Production from the Pelican Lake key resource play in the nine months of 2008 was 22,510 bbls/d, down 2 percent compared to 2007. Production from the Weyburn key resource play of 13,583 bbls/d was down 9 percent mainly due to expected natural declines offset by production adds from the infill drilling program. At Suffield, production of 13,270 bbls/d was down 16 percent mainly due to natural declines and the delay in well tie-ins. Overall, Canadian Plains crude oil production decreased 6 percent.

Per Unit Results – Crude Oil

($ per barrel)	**Canadian Plains 2008**	Canadian Plains 2007
Price (1)	**$ 93.39**	$ 46.76
Expenses		
Production and mineral taxes	**1.75**	1.11
Transportation and selling	**1.54**	1.27
Operating	**10.43**	7.89
Netback	**$ 79.67**	$ 36.49
Crude Oil Production Volumes *(bbls/d)*	**66,549**	71,159

(1) Excludes the impact of realized financial hedging.

Canadian Plains crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices. Total realized financial hedging losses on crude oil for Canadian Plains were approximately $160 million or $8.72 per bbl in 2008 compared to losses of approximately $26 million or $1.33 per bbl in 2007.

Canadian Plains crude oil per unit production and mineral taxes increased 58 percent or $0.64 per bbl in 2008 compared to 2007 primarily due to higher crude oil prices and the higher U.S./Canadian dollar exchange rate.

Canadian Plains crude oil per unit transportation and selling costs increased 21 percent or $0.27 per bbl in 2008 compared to 2007 due to the higher U.S./Canadian dollar exchange rate and additional clean oil trucking costs at Pelican Lake combined with lower overall crude oil volumes offset by lower clean oil trucking costs at Weyburn.

Canadian Plains crude oil per unit operating costs in 2008 increased 32 percent or $2.54 per bbl compared to 2007 mainly due to the higher U.S./Canadian dollar exchange rate, increased chemical costs, property tax and lease costs, workovers, electricity and salaries and benefits expenses combined with lower overall crude oil volumes.

Per Unit Results – NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas. NGLs production volumes were 1,199 bbls/d in 2008 compared to 1,206 bbls/d in 2007. NGLs realized prices increased 64 percent to $89.56 per bbl in 2008 from $54.76 per bbl in 2007, which is consistent with the higher WTI benchmark price.

DEPRECIATION, DEPLETION AND AMORTIZATION

Upstream DD&A

EnCana uses full cost accounting and calculates DD&A on a country-by-country cost centre basis.

Three Months Ended September 30, 2008 versus 2007

Upstream DD&A expenses of $1,018 million in the third quarter of 2008 increased $100 million or 11 percent compared to 2007 due to:

- Production volumes increased 6 percent;
- DD&A rates in 2008 for the U.S. were higher than 2007 primarily due to higher capitalized costs, mainly attributable to the Deep Bossier acquisition. DD&A rates in Canada for 2008 were lower than 2007 primarily as a result of the higher proved reserves; and
- DD&A in 2008 includes an impairment of $5 million related to exploration prospects in France and 2007 includes an impairment of $24 million related to exploration prospects in Oman.

Nine Months Ended September 30, 2008 versus 2007

Upstream DD&A expenses of $3,010 million in the nine months of 2008 increased $470 million or 19 percent compared to 2007 due to:

- Production volumes increased 7 percent;
- DD&A rates in 2008 for the U.S. were higher than 2007 primarily due to higher capitalized costs, mainly attributable to the Deep Bossier acquisition. DD&A rates in Canada for 2008 were lower than 2007 primarily as a result of the higher proved reserves offset in part by the impact of the higher U.S./Canadian dollar exchange rate; and
- DD&A in 2008 includes impairments of $40 million related to exploration prospects in Qatar and France and 2007 includes an impairment of $24 million related to exploration prospects in Oman.

Downstream DD&A

Downstream refining DD&A was $50 million in the third quarter of 2008 compared to $41 million in 2007 and $138 million in the nine months of 2008 compared to $115 million in 2007.

MARKET OPTIMIZATION

Financial Results

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2008**	2007	**2008**	2007
Revenues	**$ 840**	$ 629	**$ 2,112**	$ 2,107
Expenses				
Transportation and selling	**-**	-	**-**	10
Operating	**8**	11	**27**	28
Purchased product	**811**	608	**2,046**	2,042
Operating Cash Flow	**21**	10	**39**	27
Depreciation, depletion and amortization	**4**	4	**12**	11
Segment Income	**$ 17**	$ 6	**$ 27**	$ 16

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification that enhance the sale of EnCana's production.

On January 1, 2006, EnCana adopted Emerging Issues Task Force ("EITF") Abstract No. 04-13 – Accounting for Purchases and Sales of Inventory with the Same Counterparty. The effect is to record purchases and sales of inventory that are entered into in contemplation of each other with the same counterparty on a net basis in the Consolidated Statement of Earnings. These purchases and sales are used to optimize transportation or fulfill marketing arrangements. As a result of applying this policy, reported revenues and purchased product costs included offsets of $4,211 million for the nine months of 2008 compared to $3,108 million in 2007.

Revenues and Purchased product expenses increased in 2008 compared with 2007 mainly due to increased pricing offset by overall volume decreases required for Market Optimization.

CORPORATE

Financial Results

($ millions)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Revenues	$ 3,057	$ (107)	$ 1,633	$ (673)
Expenses				
Operating	3	-	(6)	(8)
Depreciation, depletion and amortization	23	25	67	64
Segment Income (Loss)	$ 3,031	$ (132)	$ 1,572	$ (729)

Revenues and operating expenses represent unrealized mark-to-market gains or losses related to financial natural gas and crude oil hedge contracts.

DD&A includes provisions for corporate assets, such as computer equipment, office furniture and leasehold improvements.

Consolidated Expenses

($ millions)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Administrative	$ 18	$ 73	$ 399	$ 263
Interest, net	147	102	428	297
Accretion of asset retirement obligation	20	17	61	46
Foreign exchange (gain) loss, net	110	74	170	69
(Gain) loss on divestitures	(124)	(29)	(141)	(87)

Administrative expenses decreased $55 million in the third quarter of 2008 compared to 2007 primarily due to lower long-term compensation expenses of $108 million as a result of the change in the EnCana share price. Administrative expenses increased $136 million in the nine months of 2008 compared to 2007 primarily due to higher staff levels and other related costs due to growth, one time charges for settlement of a lawsuit and an arbitration ruling offset by lower long-term compensation expenses. On a year-to-date basis, costs increased due to the higher U.S./Canadian dollar exchange rate, which added an additional $21 million, as well as $43 million related to the proposed corporate reorganization.

Net interest expense in the nine months of 2008 increased $131 million from 2007 primarily as a result of higher average outstanding debt. EnCana's total long-term debt, including current portion, increased $2,411 million to $9,657 million at September 30, 2008 compared with $7,246 million at September 30, 2007 primarily due to the Deep Bossier and Haynesville acquisitions. EnCana's year-to-date weighted average interest rate on outstanding debt was 5.4 percent in 2008 compared to 5.6 percent in 2007.

The foreign exchange loss of $170 million in nine months of 2008 is primarily due to the effects of the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada offset by revaluation of the partnership contribution receivable.

The gain on divestitures in 2008 relates to the divestiture of interests in Brazil. The gain on divestitures in 2007 relates to the divestiture of interests in Chad and Australia.

Summary of Unrealized Mark-to-Market Gains (Losses)

($ millions)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Revenues				
Natural Gas	$ 2,807	$ (74)	$ 1,486	$ (558)
Crude Oil	250	(33)	147	(115)
	3,057	(107)	1,633	(673)
Expenses	7	-	(6)	(7)
	3,050	(107)	1,639	(666)
Income Tax Expense (Recovery)	1,007	(38)	568	(221)
Unrealized Mark-to-Market Gains (Losses), after-tax	$ 2,043	$ (69)	$ 1,071	$ (445)

Commodity price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gains or losses reflected in corporate revenues are the result of volatility between periods in the forward curve commodity price market and changes in the balance of unsettled contracts. Further information regarding financial instrument agreements can be found in Note 17 to the Interim Consolidated Financial Statements.

Income Tax

The effective tax rate for the nine months ended September 30, 2008 was 32.7 percent compared to 25.1 percent in 2007. The majority of the difference is due to permanent differences (increase of 2.4 percent) and legislative changes having no comparative in 2008 (increase of 6 percent).

Further information regarding EnCana's effective tax rate can be found in Note 9 to the Interim Consolidated Financial Statements. EnCana's effective rate in any year is a function of the relationship between total tax (current and future) and the amount of net earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration "permanent differences", adjustment for changes to tax rates and other tax legislation, variation in the estimation of reserves and the estimate to actual differences. Permanent differences are a variety of items, including:

- The non-taxable portion of Canadian capital gains or losses;
- Non-taxable downstream partnership income;
- International financing; and
- Foreign exchange (gains) losses not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

If the proposed reorganization mentioned in the Business section of this MD&A occurs, it may result in an acceleration of future taxes for Canadian operations. However, as mentioned previously in this MD&A, the proposed reorganization has been delayed until the global debt and equity markets regain stability. Subsequently, the timing and determination of any potential impacts on Canadian future tax will be dependent upon the successful completion of the proposed reorganization.

NET CAPITAL INVESTMENT

Capital Summary

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2008**	2007	**2008**	2007
Canadian Plains	**$ 173**	$ 218	**$ 593**	$ 558
Canadian Foothills	**458**	727	**1,795**	1,779
United States	**621**	452	**1,800**	1,313
Integrated Oil	**275**	154	**804**	424
Offshore & International	**12**	13	**65**	75
Market Optimization	**4**	2	**11**	5
Corporate	**45**	9	**87**	76
Capital Investment	**1,588**	1,575	**5,155**	4,230
Acquisitions	**878**	75	**1,214**	99
Divestitures	**(442)**	(59)	**(593)**	(505)
Net Capital Investment	**$ 2,024**	$ 1,591	**$ 5,776**	$ 3,824

EnCana's Capital Investment for the nine months ended September 30, 2008 was funded by Cash Flow and debt.

Capital investment during the nine months of 2008 was primarily focused on continued development of EnCana's North American key resource plays and expansion of the Company's downstream heavy oil processing capacity through its joint venture with ConocoPhillips. Capital expenditures were also influenced by the rise in the average U.S./Canadian dollar exchange rate and change in the EnCana share price. The net impact of these factors on Capital Investment was an increase of $201 million in the nine months of 2008.

EnCana Post-Arrangement Operating Segments
Canadian Foothills and United States Capital Investment

The $503 million increase in Canadian Foothills and U.S. capital investment in the nine months of 2008 compared to the same period in 2007 was primarily due to:

- Canadian Foothills capital investment of $1,795 million in the nine months of 2008 increased $16 million primarily due to:
  - The rise in the average U.S./Canadian dollar exchange rate that increased capital by $144 million; offset by
  - Lower drilling costs due to increased focus on well tie-ins, revised completion techniques and lower capitalized costs for long-term compensation expenses. Canadian Foothills drilled 641 net wells in the nine months of 2008 compared to 1,132 net wells in 2007.
- U.S. capital investment of $1,800 million in the nine months of 2008 increased $487 million primarily due to increased drilling and completion activity in the Piceance and East Texas key resource plays, including incremental costs from the Deep Bossier acquisition offset slightly by lower capitalized costs for long-term compensation expenses. The number of net wells drilled in the U.S. increased to 571 from 497 in 2007.

Cenovus Post-Arrangement Operating Segments
Integrated Oil and Canadian Plains Capital Investment

The $415 million increase in Integrated Oil and Canadian Plains capital investment in the nine months of 2008 compared to the same period in 2007 was primarily due to:

- Integrated Oil capital investment of $804 million during the nine months of 2008 was primarily focused on continued development of the Foster Creek and Christina Lake resource plays and on capacity maintenance and bitumen expansion projects primarily at the Wood River refinery. The $380 million increase in capital investment in the nine months of 2008 compared to the same period in 2007 was primarily due to:
  - Higher facility costs at Foster Creek and Christina Lake and spending related to the Wood River CORE project. Facility expenditures at Foster Creek are expected to increase plant capacity to 120,000 bbls/d to accommodate Phases D and E expansions. Christina Lake facility costs are expected to increase plant capacity to 58,000 bbls/d to accommodate Phases B and C expansion. In addition, drilling costs were higher mainly due to drilling of 142 additional stratigraphic test wells (54 net to EnCana) at Foster Creek, Christina Lake and Borealis related to the next phases of development compared to the same period in 2007. The Wood River CORE project received regulatory approvals in the third quarter of 2008 and is expected to cost about $1.8 billion, net to EnCana, over the next three years. At the end of the expansion, crude oil refining capacity will increase from 306,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and heavy crude oil refining capacity will more than double to 240,000 bbls/day.
  - The rise in the average U.S./Canadian dollar exchange rate that increased capital by $20 million offset by lower capitalized costs for long-term compensation expenses.
- Canadian Plains capital investment of $593 million in the nine months of 2008 increased $35 million primarily due to the rise in the average U.S./Canadian dollar exchange rate that increased capital by $45 million, as well as increased land purchases and facility work offset by lower drilling and completion costs. Canadian Plains drilled 1,034 net wells in the nine months of 2008 compared to 1,510 net wells in 2007, focusing more on deeper integrated wells in 2008.

Corporate Capital Investment

Corporate capital investment in 2008 and 2007 included land purchases and costs related to the development of a Calgary office complex. On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and entered into a 25 year lease agreement with a third party developer. In addition, capital investment has been directed to business information systems and leasehold improvements.

Acquisitions and Divestitures

Acquisitions included land purchases of approximately $1,089 million in the Haynesville Shale play in Louisiana during the nine months of 2008 and minor property acquisitions in 2007.

In September 2008, EnCana completed the sale of its interests in Brazil for net proceeds of $164 million resulting in a gain on sale of $124 million before-tax ($99 million after-tax). EnCana also completed other minor divestitures during the nine months of 2008.

EnCana completed the following divestitures in the nine months of 2007:

- The sale of assets in Australia for $31 million resulting in a gain on sale of $30 million before-tax ($25 million after-tax);
- The sale of certain assets in the Mackenzie Delta and Beaufort Sea for proceeds of $159 million;
- The sale of its interests in Chad for $208 million resulting in a gain on sale of $59 million;

- The sale of The Bow office project assets for approximately $57 million, largely representing its investment at the date of sale; and
- Other minor divestitures for combined proceeds of $50 million.

Proceeds from these 2007 divestitures were directed primarily to the purchase of shares under EnCana's NCIB.

Liquidity and Capital Resources

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	2007	**2008**	2007
Net cash from (used in)				
Operating activities	**$ 3,058**	$ 2,180	**$ 6,812**	$ 6,236
Investing activities	**(2,326)**	(1,490)	**(5,896)**	(3,832)
Financing activities	**(881)**	(739)	**(837)**	(2,306)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**(7)**	9	**(10)**	15
Increase (decrease) in cash and cash equivalents	**$ (156)**	$ (40)	**$ 69**	$ 113

Operating Activities

Cash Flow was $2,809 million during the third quarter of 2008 compared to $2,218 million for the same period in 2007. On a year-to-date basis, Cash Flow was $8,087 million compared to $6,519 million for the same period in 2007. Reasons for this change are discussed under the Cash Flow section of this MD&A. Year-to-date net cash provided by operating activities was also impacted by net changes in non-cash working capital, including increases in risk management assets and inventories and a decrease in income tax payable.

Investing Activities

Net cash used for investing activities in the nine months of 2008 increased $2,064 million compared to the same period in 2007. Capital expenditures, including property acquisitions, in the nine months of 2008 increased $2,040 million compared to 2007. Reasons for this change are discussed under the Net Capital Investment section of this MD&A.

Financing Activities

Net issuance of long-term debt in the nine months of 2008 was $310 million compared to net issuance of $15 million for the same period in 2007. EnCana's debt adjusted for working capital ("net debt") was $8,366 million as at September 30, 2008 compared with $10,726 million as at December 31, 2007.

EnCana maintains numerous committed bank credit facilities and shelf prospectuses.

On January 18, 2008, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C$750 million. The notes have a coupon rate of 5.80 percent and mature on January 18, 2018. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

On March 11, 2008, EnCana filed a shelf prospectus whereby it may issue from time to time up to $4.0 billion, or the equivalent in foreign currencies, of debt securities in the U.S. The shelf prospectus replaces EnCana's $2.0 billion shelf prospectus which was fully utilized and EnCana Holdings Finance Corp.'s $2.0 billion shelf prospectus which expired on July 9, 2008.

As at September 30, 2008, EnCana had available unused committed bank credit facilities in the amount of $2.7 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.2 billion.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the Company's announcement to split into two focused energy companies, Standard & Poor's Ratings Service assigned a rating of A- and placed the Company on "CreditWatch with Negative Implications", DBRS Limited assigned a rating of A(low) and placed the Company "Under Review with Developing Implications" and Moody's Investors Services assigned a rating of Baa2 and changed the outlook to "Stable" from "Positive".

In light of the current market situation, EnCana continues to employ a conservative capital structure in which approximately 78 percent of outstanding debt is fixed-rate debt with maturities between 2009 and 2038. Debt maturities of $250 million in August 2009 and $200 million in September 2010 are modest relative to EnCana's financial capacity and cash flow.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under a NCIB. During the third quarter of 2008, EnCana did not purchase any of its Common Shares compared with 3.5 million Common Shares purchased for total consideration of $218 million for the same period in 2007. During the nine months of 2008, EnCana purchased 4.8 million of its Common Shares for total consideration of $326 million compared with 38.9 million Common Shares for total consideration of $2,025 million for the same period in 2007.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. EnCana doubled its quarterly dividend to 40 cents per share in 2008 and payments for the nine months ended September 30, 2008 totaled $899 million compared with $453 million for the same period in 2007. These dividends were funded by Cash Flow.

Financial Metrics

	September 30 2008	December 31 2007
Net Debt to Capitalization (1)	**26%**	34%
Net Debt to Adjusted EBITDA (2)	**0.6x**	1.2x

(1) Net Debt is a non-GAAP measure defined as Long-Term Debt plus Current Liabilities less Current Assets. Capitalization is a non-GAAP measure defined as Net Debt plus Shareholders' Equity.

(2) Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Net Earnings from Continuing Operations before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Net Debt to Capitalization and Net Debt to Adjusted EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength. EnCana's Net Debt to Capitalization ratio decreased to 26 percent from 34 percent at December 31, 2007 primarily due to unrealized mark-to-market gains on risk management instruments which decreased Net Debt. Excluding this impact to working capital, the Net Debt to Capitalization ratio would have been 29 percent at September 30, 2008 and would have remained unchanged at 34 percent at December 31, 2007.

Free Cash Flow

EnCana's third quarter 2008 Free Cash Flow increased $578 million and nine months of 2008 Free Cash Flow increased $643 million compared to the same periods in 2007. Reasons for the increase in total Cash Flow and capital investment are discussed under the Cash Flow and Net Capital Investment sections of this MD&A.

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	2008	2007	2008	2007
Cash Flow (1)	**$ 2,809**	$ 2,218	**$ 8,087**	$ 6,519
Capital Investment	**1,588**	1,575	**5,155**	4,230
Free Cash Flow (2)	**$ 1,221**	$ 643	**$ 2,932**	$ 2,289

(1) Cash Flow is a non-GAAP measure and is defined under the "Cash Flow" section of this MD&A.

(2) Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of Capital Investment, excluding net acquisitions and divestitures, and is used by Management to determine the funds available for other investing and/or financing activities.

Outstanding Share Data

(millions)	September 30 2008	December 31 2007
Common Shares outstanding, beginning of year	**750.2**	777.9
Common Shares issued under option plans	**2.9**	8.3
Common Shares purchased	**(2.8)**	(36.0)
Common Shares outstanding, end of period	**750.3**	750.2
Weighted average Common Shares outstanding – diluted	**752.0**	764.6

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. There were no Preferred Shares outstanding as at September 30, 2008 and 2007.

Employees have been granted options to purchase Common Shares under various plans. At September 30, 2008, approximately 0.6 million options without Tandem Share Appreciation Rights ("TSARs") attached were outstanding, all of which are exercisable.

Long-term incentives may be granted to EnCana employees in the form of stock options and Performance Share Units ("PSUs"). Stock options granted after December 31, 2003 have an associated TSAR attached which gives employees the right to elect to receive a cash payment equal to the excess of the market price of EnCana's common shares over the exercise price of their stock option in exchange for surrendering their stock option. The exercise of a TSAR, for a cash payment, does not result in the issuance of any additional EnCana common shares, so has no dilutive effect. Historically, virtually all employees holding options with TSARs attached wishing to realize the value of their options have exercised their TSARs to receive a cash payment. At September 30, 2008, approximately 32.7 million options with TSARs attached were outstanding, of which 9.9 million are exercisable. During the first quarter of 2008, vesting provisions for the PSUs granted in 2005 were met and 2.0 million shares were distributed from the EnCana Employee Benefit Plan Trust. Additional information on these incentives is contained in Note 17 of the Company's audited Consolidated Financial Statements for the year ended December 31, 2007.

In 2008, EnCana granted Share Appreciation Rights ("SARs") and Performance SARs to certain employees which entitles the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the grant price. SARs are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the grant date. Performance SARs vest and expire under the same terms and service conditions as SARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance SARs that do not vest when eligible are forfeited. At September 30, 2008, approximately 2.9 million SARs and Performance SARs were outstanding, of which none are exercisable.

Contractual Obligations and Contingencies

EnCana has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

Included in EnCana's total long-term debt obligations of $9,679 million at September 30, 2008 are $2,150 million in obligations related to Bankers' Acceptances, Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 – 5 years as described in Note 17 to the Interim Consolidated Financial Statements. Further details regarding EnCana's long-term debt are described in Note 11 to the Interim Consolidated Financial Statements.

As at September 30, 2008, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 38 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 101 Bcf at a weighted average price of $4.20 per Mcf. As at September 30, 2008, these transactions had an unrealized loss of $284 million.

Leases

In the normal course of business, EnCana leases office space for personnel who support field operations and for corporate purposes.

Deep Panuke

In October 2007, EnCana received regulatory approval from the Canada-Nova Scotia Offshore Petroleum Board to develop the Deep Panuke natural gas project located about 175 kilometres offshore Nova Scotia. Expected to start production in 2010, the approximately $700 million project is expected to deliver between 200 MMcf/d and 300 MMcf/d to markets in Canada and the northeast U.S.

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre ("PFC") for the Deep Panuke project. The agreement is for Single Buoy Moorings to construct a production facility that EnCana will lease upon delivery, expected in late 2010. EnCana also has the option to purchase the facility. EnCana has determined that it has substantially all the construction period risk and consequently is reporting the PFC as an asset under construction during the construction period. Once in service, the asset will be classified as a capital lease.

The Bow

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third party developer. Cost of design changes to the building requested by EnCana and leasehold improvements will be the responsibility of the Company.

Variable Interest Entities ("VIEs")

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes.

Pursuant to the agreements with Brown Haynesville and Brown Southwest, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The arrangements with Brown Haynesville and Brown Southwest will be completed on March 24, 2009 and January 19, 2009 respectively and the assets will be transferred to EnCana at that time. EnCana has determined that each relationship with Brown Haynesville and Brown Southwest represents an interest in a VIE and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Haynesville and Brown Southwest from the dates of acquisition.

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately $2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC ("Brown Kilgore"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Kilgore represented an interest in VIE from November 20, 2007 to May 18, 2008. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Kilgore. On May 18, 2008, when the arrangement with Brown Kilgore was completed, the assets were transferred to EnCana.

Legal Proceedings

EnCana is involved in various legal claims associated with the normal course of operations and believes it has made adequate provision for such legal claims.

Discontinued Merchant Energy Operations

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court for payment of $20.5 million and $2.4 million, respectively. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") for $20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million. Also, without admitting any liability whatsoever, WD concluded settlement negotiations with a group of individual plaintiffs. It was agreed that WD would settle these claims for $23 million. Execution of the Settlement Agreement is pending.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against this outstanding claim; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

Accounting Policies and Estimates

New Accounting Standards Adopted

As disclosed in the year-end MD&A, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 "Inventories", Section 3863 "Financial Instruments – Presentation", Section 3862 "Financial Instruments – Disclosures" and Section 1535 "Capital Disclosures" on January 1, 2008. The adoption of these standards has had no material impact on the Company's Net Earnings or Cash Flows. Additional information on the effects of the implementation of the new standards can be found in Note 2 to the Interim Consolidated Financial Statements.

Recent Accounting Pronouncements

As of January 1, 2009, EnCana will be required to adopt the CICA Handbook Section 3064, "Goodwill and Intangible Assets", which will replace the existing Goodwill and Intangible Assets standard. The new standard revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. As EnCana will be required to report its results in accordance with IFRS starting in 2011, the Company is assessing the potential impacts of this changeover and developing its plan accordingly.

Risk Management

EnCana's results are affected by:

- financial risks (including commodity price, foreign exchange, interest rate and credit risks);
- operational risks;
- environmental, health, safety and security risks; and
- reputational risks.

EnCana takes a proactive approach in the identification and management of risks that can affect the Company. Mitigation of these risks include, but are not limited to, the use of derivative instruments, credit policies, operational policies, maintaining adequate insurance, environmental and safety policies as well as policies and enforcement procedures that can affect EnCana's reputation. Further discussion regarding the specific risks and mitigation of these risks can be found in the December 31, 2007 Management's Discussion and Analysis and Note 17 to the Interim Consolidated Financial Statements.

Alberta Royalty Framework

On October 25, 2007, the Alberta Government announced a new Alberta Royalty Framework ("ARF"). The ARF establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. The changes introduced by the ARF are to be effective January 1, 2009.

The significant changes to the royalty regime require new legislation, changes to existing legislation and regulation and development of proprietary software by the Alberta Government to support the calculation and collection of royalties.

Climate Change

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and other air pollutants while some jurisdictions have provided details on these regulations. It is anticipated that other jurisdictions will announce emissions reduction plans in the future.

Canadian Federal GHG regulations are expected to be developed later this fall, finalized in 2009 and come into force on January 1, 2010. Additional details on the regulatory framework for greenhouse gases that was announced in April 2007 have been released, which include information on reporting thresholds, facility-specific and sector-wide and corporate-specific targets, carbon capture and storage based targets, cleaner fuel standard for new facilities (built after 2004), technology fund, emissions coverage, cogeneration, harmonization and an offsets system. These details provide some clarification on the direction the federal government would like to take on emissions policy, but specific details on the costs to the Company will not be known until additional information can be gathered from the government.

As these federal and regional programs are under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana will continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Alberta Government has set targets for GHG emissions reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. In Alberta, EnCana has four facilities covered under the recently enacted emissions regulations. In the first year of compliance, due to operational improvements and cogeneration assets EnCana generated emissions credits to use towards future compliance with these regulations. The forecast cost of carbon associated with the Alberta regulations is not material to EnCana at this time and is being actively managed.

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' will be applied to virtually all fossil fuels, including diesel, natural gas, coal, propane, and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate starts at C$10 per tonne of carbon equivalent emissions, rising by C$5 per tonne a year for the next four years. The forecast cost of carbon associated with the British Columbia regulations is not material to EnCana at this time and is being actively managed.

EnCana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company's efforts with respect to emissions management are founded on the following key elements:

- our significant production weighting in natural gas;
- our recognition as an industry leader in CO_2 sequestration;
- our focus on energy efficiency and the development of technology to reduce GHG emissions;
- our involvement in the creation of industry best practices; and
- our industry leading steam to oil ratio, which translates directly into lower emissions intensity.

EnCana's strategy for addressing the implications of emerging carbon regulations is proactive and is comprised of three principal elements:

1. Manage Existing Costs
   When regulations are implemented a cost is placed on EnCana's emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption, and a focus on minimizing our steam to oil ratio help to support and drive our focus on cost reduction.
2. Respond to Price Signals
   As regulatory regimes for GHGs develop in the jurisdictions where we work inevitably price signals begin to emerge. We have initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of our operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon, where appropriate, EnCana is also attempting to realize the associated value of its reduction projects.
3. Anticipate Future Carbon Constrained Scenarios
   EnCana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions we gain useful knowledge that allows us to explore different strategies for managing our emissions and costs. These scenarios inform our long range planning and our analyses on the implications of regulatory trends.

EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's GHG emissions is available in the Corporate Responsibility Report that is available on our website at www.encana.com.

Outlook

As discussed in the EnCana's Business section of this MD&A, the Company announced its plans to split into two highly focused energy companies. EnCana is currently preparing the documentation and developing the plans, related to organizational structures, resources and corporate functions that are required for the proposed companies, to give effect to the Arrangement. Given the uncertainty and volatility in the global financial markets, EnCana is choosing to delay the timing of a shareholder vote that was contemplated to take place in December 2008, until clear signs of stabilization return to the financial markets.

EnCana, post-Arrangement, plans to focus on growing natural gas production from its diversified portfolio of existing and emerging unconventional resource plays in North America. Cenovus, post-Arrangement, plans to focus on developing its high quality in-situ oil resources and expanding its downstream heavy oil processing capacity through its joint venture with ConocoPhillips.

Volatility in crude oil prices is expected to continue throughout 2008 as a result of market uncertainties over supply and refining disruptions, changes in demand due to the overall state of the world economies, OPEC actions and the worldwide credit and liquidity crisis. Canadian crude prices will face added uncertainty due to the risk of refinery disruptions in an already tight U.S. Midwest market and growing domestic production could result in pipeline constraints out of Western Canada.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that North American conventional gas supply has peaked and that unconventional resource plays can offset conventional gas production declines over the next few years. Past this period, the industry's ability to continue to grow gas supply is expected to be challenged in North America by land access and regulatory issues.

The Company expects its 2008 capital investment program to be funded from Cash Flow and debt.

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Additional detail regarding the impact of these factors on EnCana's 2008 results is available in the Corporate Guidance on our website at www.encana.com. EnCana updated its Corporate Guidance in the third quarter of 2008. EnCana's news release dated October 23, 2008 and financial statements are available on www.sedar.com.

Advisories

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: the planned Arrangement; the expected future attributes of each of EnCana and Cenovus following any such Arrangement; the anticipated benefits of the planned Arrangement; the expected timing for completion of the Arrangement and the conditions which are or may be required prior to proceeding with the Arrangement; the expected tax impact of the planned Arrangement; projections relating to the adequacy of the Company's provision for taxes; the potential impact of implementation of the Alberta Royalty Framework on EnCana's financial condition and projected 2008 capital investments; projections with respect to growth of natural gas production from unconventional resource plays and in-situ oil resources including with respect to Foster Creek/Christina Lake, through 2016, the planned expansions of the Company's downstream heavy oil processing capacity and the capital costs of the same; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil prices in 2008 and beyond and the reasons therefor; the Company's projected capital investment levels for 2008 and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's defence of lawsuits; the impact of the climate change initiatives on operating costs; the impact of Western Canada pipeline constraints and potential refinery disruptions on future Canadian crude oil prices; projections that the Company's Bankers' Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; projections relating to the Company's Deep Panuke project, including projected production levels and the timing thereof and the timing for completion of project facilities; expected completion dates of the arrangements with Brown Southwest and Brown Haynesville; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to offset future conventional gas production declines over the next few years. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: the ability to obtain any necessary approvals, waivers, consents, court orders and other requirements necessary or desirable to permit or facilitate the Arrangement; the risk that any applicable conditions to complete the Arrangement may not occur or be satisfied; volatility of and assumptions regarding oil and gas prices; assumptions based upon EnCana's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; the ability of the Company and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology and the application thereof to the business of the Company and Cenovus; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

EnCana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that EnCana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in EnCana's news release dated October 23, 2008, which news release is available on EnCana's website at www.encana.com and on SEDAR at www.sedar.com.

OIL AND GAS INFORMATION

EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The reserves quantities disclosed by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

Crude Oil, NGLs and Natural Gas Conversions

In this document, certain crude oil and NGLs volumes have been converted to millions of cubic feet equivalent ("MMcfe") or thousands of cubic feet equivalent ("Mcfe") on the basis of one barrel ("bbl") to six thousand cubic feet ("Mcf"). Also, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE"), thousands of BOE ("MBOE") or millions of BOE ("MMBOE") on the same basis. MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head.

Resource Play

Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this document and the Interim Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after-royalties basis unless otherwise noted.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Cash Flow from Continuing Operations, Cash Flow per share – diluted, Free Cash Flow, Operating Earnings, Operating Earnings from Continuing Operations, Operating Earnings per share – diluted, Adjusted EBITDA, Net Debt and Capitalization and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in this document as these measures are discussed and presented.

References to EnCana

For convenience, references in this document to "EnCana", the "Company", "we", "us" and "our" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company's public filings found at www.sedar.com and on the Company's website at www.encana.com.

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*

($ millions, except per share amounts)		Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
REVENUES, NET OF ROYALTIES	*(Note 5)*	**$ 10,766**	$ 5,596	**$ 23,429**	$ 15,645
EXPENSES	*(Note 5)*				
Production and mineral taxes		**138**	79	**406**	228
Transportation and selling		**360**	220	**1,006**	732
Operating		**521**	530	**1,926**	1,646
Purchased product		**3,445**	2,192	**8,720**	5,879
Depreciation, depletion and amortization		**1,095**	988	**3,227**	2,730
Administrative		**18**	73	**399**	263
Interest, net	*(Note 7)*	**147**	102	**428**	297
Accretion of asset retirement obligation	*(Note 12)*	**20**	17	**61**	46
Foreign exchange (gain) loss, net	*(Note 8)*	**110**	74	**170**	69
(Gain) loss on divestitures	*(Note 6)*	**(124)**	(29)	**(141)**	(87)
		5,730	4,246	**16,202**	11,803
NET EARNINGS BEFORE INCOME TAX		**5,036**	1,350	**7,227**	3,842
Income tax expense	*(Note 9)*	**1,483**	416	**2,360**	965
NET EARNINGS		**$ 3,553**	$ 934	**$ 4,867**	$ 2,877
NET EARNINGS PER COMMON SHARE	*(Note 16)*				
Basic		**$ 4.74**	$ 1.24	**$ 6.49**	$ 3.79
Diluted		**$ 4.73**	$ 1.24	**$ 6.47**	$ 3.75

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Nine Months Ended September 30, 2008	2007
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 13,082**	$ 11,344
Net Earnings		**4,867**	2,877
Dividends on Common Shares		**(899)**	(453)
Charges for Normal Course Issuer Bid	*(Note 13)*	**(243)**	(1,618)
RETAINED EARNINGS, END OF PERIOD		**$ 16,807**	$ 12,150

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME *(unaudited)*

($ millions)	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
NET EARNINGS	**$ 3,553**	$ 934	**$ 4,867**	$ 2,877
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Foreign Currency Translation Adjustment	**(430)**	859	**(782)**	1,798
COMPREHENSIVE INCOME	**$ 3,123**	$ 1,793	**$ 4,085**	$ 4,675

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME *(unaudited)*

($ millions)	Nine Months Ended September 30, 2008	2007
ACCUMULATED OTHER COMPREHENSIVE INCOME, BEGINNING OF YEAR	**$ 3,063**	$ 1,375
Foreign Currency Translation Adjustment	**(782)**	1,798
ACCUMULATED OTHER COMPREHENSIVE INCOME, END OF PERIOD	**$ 2,281**	$ 3,173

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		**As at September 30, 2008**	As at December 31, 2007
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 622**	$ 553
Accounts receivable and accrued revenues		**2,473**	2,381
Current portion of partnership contribution receivable		**309**	297
Risk management	*(Note 17)*	**1,578**	385
Inventories	*(Note 10)*	**1,280**	828
		6,262	4,444
Property, Plant and Equipment, net	*(Note 5)*	**37,374**	35,865
Investments and Other Assets		**758**	607
Partnership Contribution Receivable		**2,914**	3,147
Risk Management	*(Note 17)*	**459**	18
Goodwill		**2,729**	2,893
	(Note 5)	**$ 50,496**	$ 46,974
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 4,027**	$ 3,982
Income tax payable		**569**	1,150
Current portion of partnership contribution payable		**301**	288
Risk management	*(Note 17)*	**74**	207
Current portion of long-term debt	*(Note 11)*	**250**	703
		5,221	6,330
Long-Term Debt	*(Note 11)*	**9,407**	8,840
Other Liabilities		**511**	242
Partnership Contribution Payable		**2,936**	3,163
Risk Management	*(Note 17)*	**-**	29
Asset Retirement Obligation	*(Note 12)*	**1,374**	1,458
Future Income Taxes		**7,404**	6,208
		26,853	26,270
Shareholders' Equity			
Share capital	*(Note 13)*	**4,555**	4,479
Paid in surplus		**-**	80
Retained earnings		**16,807**	13,082
Accumulated other comprehensive income		**2,281**	3,063
Total Shareholders' Equity		**23,643**	20,704
		$ 50,496	$ 46,974

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

($ millions)		Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
OPERATING ACTIVITIES					
Net earnings		**$ 3,553**	$ 934	**$ 4,867**	$ 2,877
Depreciation, depletion and amortization		**1,095**	988	**3,227**	2,730
Future income taxes	*(Note 9)*	**1,418**	102	**1,491**	(9)
Cash tax on sale of assets	*(Note 9)*	**25**	-	**25**	-
Unrealized (gain) loss on risk management	*(Note 17)*	**(3,050)**	107	**(1,639)**	666
Unrealized foreign exchange (gain) loss		**84**	17	**149**	93
Accretion of asset retirement obligation	*(Note 12)*	**20**	17	**61**	46
(Gain) loss on divestitures	*(Note 6)*	**(124)**	(29)	**(141)**	(87)
Other		**(212)**	82	**47**	203
Net change in other assets and liabilities		**(19)**	1	**(283)**	5
Net change in non-cash working capital		**268**	(39)	**(992)**	(288)
Cash From Operating Activities		**3,058**	2,180	**6,812**	6,236
INVESTING ACTIVITIES					
Capital expenditures	*(Note 5)*	**(2,466)**	(1,650)	**(6,369)**	(4,329)
Proceeds from divestitures	*(Note 6)*	**442**	59	**593**	505
Cash tax on sale of assets	*(Note 9)*	**(25)**	-	**(25)**	-
Net change in investments and other		**(157)**	32	**(166)**	26
Net change in non-cash working capital		**(120)**	69	**71**	(34)
Cash (Used in) Investing Activities		**(2,326)**	(1,490)	**(5,896)**	(3,832)
FINANCING ACTIVITIES					
Net issuance (repayment) of revolving long-term debt		**(116)**	(871)	**251**	(909)
Issuance of long-term debt	*(Note 11)*	**-**	492	**723**	924
Repayment of long-term debt		**(468)**	-	**(664)**	-
Issuance of common shares	*(Note 13)*	**2**	5	**78**	158
Purchase of common shares	*(Note 13)*	**-**	(218)	**(326)**	(2,025)
Dividends on common shares		**(299)**	(149)	**(899)**	(453)
Other		**-**	2	**-**	(1)
Cash (Used in) Financing Activities		**(881)**	(739)	**(837)**	(2,306)
FOREIGN EXCHANGE GAIN (LOSS) ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**(7)**	9	**(10)**	15
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**(156)**	(40)	**69**	113
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**778**	555	**553**	402
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 622**	$ 515	**$ 622**	$ 515

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements *(unaudited)*
(All amounts in $ millions unless otherwise specified)

1. BASIS OF PRESENTATION

The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. EnCana's operations are in the business of exploration for, and development, production and marketing of natural gas, crude oil and natural gas liquids ("NGLs"), refining operations and power generation operations.

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2007, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2007.

2. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

As disclosed in the December 31, 2007 annual audited Consolidated Financial Statements, on January 1, 2008, the Company adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook Sections:

- "Inventories", Section 3031. The new standard replaces the previous inventories standard and requires inventory to be valued on a first-in, first-out or weighted average basis, which is consistent with EnCana's former accounting policy. The new standard allows the reversal of previous write-downs to net realizable value when there is a subsequent increase in the value of inventories. The adoption of this standard has had no material impact on EnCana's Consolidated Financial Statements.
- "Financial Instruments – Presentation", Section 3863 and "Financial Instruments – Disclosures", Section 3862. The new disclosure standard increases EnCana's disclosure regarding the nature and extent of the risks associated with financial instruments and how those risks are managed (See Note 17). The new presentation standard carries forward the former presentation requirements.
- "Capital Disclosures", Section 1535. The new standard requires EnCana to disclose its objectives, policies and processes for managing its capital structure (See Note 14).

3. RECENT ACCOUNTING PRONOUNCEMENTS

As of January 1, 2009, EnCana will be required to adopt the CICA Handbook Section 3064, "Goodwill and Intangible Assets", which will replace the existing Goodwill and Intangible Assets standard. The new standard revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. As EnCana will be required to report its results in accordance with IFRS starting in 2011, the Company is assessing the potential impacts of this changeover and developing its plan accordingly.

Notes to Consolidated Financial Statements *(unaudited)*
(All amounts in $ millions unless otherwise specified)

4. PROPOSED CORPORATE REORGANIZATION

On May 11, 2008, EnCana announced its plans to split into two independent energy companies - one a North American natural gas company and the other a fully integrated oil company with in-situ oil properties and refineries supplemented by reliable production from various gas and oil resource plays. The proposed corporate reorganization (the "Arrangement") was expected to close in early January 2009.

Subsequent to September 30, 2008, EnCana announced the proposed Arrangement will be delayed until the global debt and equity markets regain stability. The proposed Arrangement is expected to be implemented through a court approved Plan of Arrangement and is subject to shareholder approval. The reorganization would result in two publicly traded entities with the names of Cenovus Energy Inc. ("Cenovus") (prior working name "IOCo") and EnCana Corporation (prior working name "GasCo"). Each EnCana shareholder would receive one share of each entity in exchange for each EnCana Common Share held.

5. SEGMENTED INFORMATION

As a result of the proposed Arrangement, EnCana has changed its reportable segments to reflect the realigned reporting hierarchies. The most significant change results in EnCana now presenting Canadian Plains and Canadian Foothills as separate operating segments. These were previously aggregated and presented in the Canada segment. Prior periods have been restated to reflect the new presentation.

The Company has defined its continuing operations into the following segments:

- **Canadian Plains, Canadian Foothills, United States and Offshore and International** segments include the Company's exploration for, and development and production of natural gas, crude oil and NGLs and other related activities. The majority of the Company's operations are located in Canada and the United States. The Offshore and International segment is mainly focused on opportunities in Atlantic Canada and Europe.
- **Integrated Oil** is focused on two lines of business: the exploration for, and development and production of bitumen in Canada using in-situ recovery methods; and the refining of crude oil into petroleum and chemical products located in the United States. This segment includes EnCana's 50 percent interest in the joint venture with ConocoPhillips.
- **Market Optimization** is conducted by the Midstream & Marketing division. The Marketing groups' primary responsibility is the sale of the Company's proprietary production. The results are included in the Canadian Plains, Canadian Foothills, United States and Integrated Oil segments. Correspondingly, the Marketing groups also undertake market optimization activities which comprise third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.
- **Corporate** includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization markets substantially all of the Company's upstream production to third-party customers. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Results of Operations (For the three months ended September 30)

	Canadian Plains		Canadian Foothills		United States	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,139**	$ 824	**$ 1,168**	$ 881	**$ 1,477**	$ 1,103
Expenses						
Production and mineral taxes	**27**	17	**14**	10	**97**	52
Transportation and selling	**32**	26	**57**	51	**132**	77
Operating	**96**	103	**120**	129	**127**	140
Purchased product	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**231**	253	**293**	280	**435**	305
Segment Income (Loss)	**$ 753**	$ 425	**$ 684**	$ 411	**$ 686**	$ 529

	Integrated Oil		Offshore & International		Market Optimization	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 3,085**	$ 2,265	**$ -**	$ 1	**$ 840**	$ 629
Expenses						
Production and mineral taxes	**-**	-	**-**	-	**-**	-
Transportation and selling	**139**	66	**-**	-	**-**	-
Operating	**173**	147	**(6)**	-	**8**	11
Purchased product	**2,634**	1,584	**-**	-	**811**	608
Depreciation, depletion and amortization	**104**	97	**5**	24	**4**	4
Segment Income (Loss)	**$ 35**	$ 371	**$ 1**	$ (23)	**$ 17**	$ 6

	Corporate		Consolidated	
	2008	2007	**2008**	2007
Revenues, Net of Royalties	**$ 3,057**	$ (107)	**$ 10,766**	$ 5,596
Expenses				
Production and mineral taxes	**-**	-	**138**	79
Transportation and selling	**-**	-	**360**	220
Operating	**3**	-	**521**	530
Purchased product	**-**	-	**3,445**	2,192
Depreciation, depletion and amortization	**23**	25	**1,095**	988
Segment Income (Loss)	**$ 3,031**	$ (132)	**5,207**	1,587
Administrative			**18**	73
Interest, net			**147**	102
Accretion of asset retirement obligation			**20**	17
Foreign exchange (gain) loss, net			**110**	74
(Gain) loss on divestitures			**(124)**	(29)
			171	237
Net Earnings Before Income Tax			**5,036**	1,350
Income tax expense			**1,483**	416
Net Earnings			**$ 3,553**	$ 934

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Results of Operations (For the three months ended September 30)

Geographic and Product Information

Canadian Plains

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 576**	$ 498	**$ 559**	$ 323	**$ 4**	$ 3	**$ 1,139**	$ 824
Expenses								
Production and mineral taxes	**14**	11	**13**	6	**-**	-	**27**	17
Transportation and selling	**18**	18	**14**	8	**-**	-	**32**	26
Operating	**44**	49	**51**	53	**1**	1	**96**	103
Operating Cash Flow	**$ 500**	$ 420	**$ 481**	$ 256	**$ 3**	$ 2	**$ 984**	$ 678

Canadian Foothills

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 982**	$ 765	**$ 172**	$ 100	**$ 14**	$ 16	**$ 1,168**	$ 881
Expenses								
Production and mineral taxes	**12**	9	**2**	1	**-**	-	**14**	10
Transportation and selling	**54**	48	**3**	3	**-**	-	**57**	51
Operating	**108**	114	**7**	9	**5**	6	**120**	129
Operating Cash Flow	**$ 808**	$ 594	**$ 160**	$ 87	**$ 9**	$ 10	**$ 977**	$ 691

United States

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,263**	$ 934	**$ 124**	$ 86	**$ 90**	$ 83	**$ 1,477**	$ 1,103
Expenses								
Production and mineral taxes	**86**	49	**11**	3	**-**	-	**97**	52
Transportation and selling	**132**	77	**-**	-	**-**	-	**132**	77
Operating	**59**	68	**-**	-	**68**	72	**127**	140
Operating Cash Flow	**$ 986**	$ 740	**$ 113**	$ 83	**$ 22**	$ 11	**$ 1,121**	$ 834

Integrated Oil

	Oil		Downstream Refining		Other *		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 362**	$ 160	**$ 2,699**	$ 2,049	**$ 24**	$ 56	**$ 3,085**	$ 2,265
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**-**	-	**-**	-
Transportation and selling	**137**	62	**-**	-	**2**	4	**139**	66
Operating	**42**	35	**116**	98	**15**	14	**173**	147
Purchased product	**-**	-	**2,679**	1,607	**(45)**	(23)	**2,634**	1,584
Operating Cash Flow	**$ 183**	$ 63	**$ (96)**	$ 344	**$ 52**	$ 61	**$ 139**	$ 468

* Includes exploration and production of natural gas and bitumen from the Athabasca and Senlac properties.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Results of Operations (For the nine months ended September 30)

	Canadian Plains		Canadian Foothills		United States	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 3,383**	$ 2,524	**$ 3,432**	$ 2,662	**$ 4,356**	$ 3,194
Expenses						
Production and mineral taxes	**64**	52	**30**	34	**311**	142
Transportation and selling	**84**	84	**167**	149	**367**	220
Operating	**385**	312	**478**	383	**482**	441
Purchased product	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**714**	725	**853**	773	**1,253**	851
Segment Income (Loss)	**$ 2,136**	$ 1,351	**$ 1,904**	$ 1,323	**$ 1,943**	$ 1,540

	Integrated Oil		Offshore & International		Market Optimization	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 8,512**	$ 5,831	**$ 1**	$ -	**$ 2,112**	$ 2,107
Expenses						
Production and mineral taxes	**1**	-	**-**	-	**-**	-
Transportation and selling	**388**	269	**-**	-	**-**	10
Operating	**565**	488	**(5)**	2	**27**	28
Purchased product	**6,674**	3,837	**-**	-	**2,046**	2,042
Depreciation, depletion and amortization	**288**	281	**40**	25	**12**	11
Segment Income (Loss)	**$ 596**	$ 956	**$ (34)**	$ (27)	**$ 27**	$ 16

	Corporate		Consolidated	
	2008	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,633**	$ (673)	**$ 23,429**	$ 15,645
Expenses				
Production and mineral taxes	**-**	-	**406**	228
Transportation and selling	**-**	-	**1,006**	732
Operating	**(6)**	(8)	**1,926**	1,646
Purchased product	**-**	-	**8,720**	5,879
Depreciation, depletion and amortization	**67**	64	**3,227**	2,730
Segment Income (Loss)	**$ 1,572**	$ (729)	**8,144**	4,430
Administrative			**399**	263
Interest, net			**428**	297
Accretion of asset retirement obligation			**61**	46
Foreign exchange (gain) loss, net			**170**	69
(Gain) loss on divestitures			**(141)**	(87)
			917	588
Net Earnings Before Income Tax			**7,227**	3,842
Income tax expense			**2,360**	965
Net Earnings			**$ 4,867**	$ 2,877

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Results of Operations (For the nine months ended September 30)

Geographic and Product Information

Canadian Plains

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,795**	$ 1,619	**$ 1,580**	$ 896	**$ 8**	$ 9	**$ 3,383**	$ 2,524
Expenses								
Production and mineral taxes	**32**	31	**32**	21	**-**	-	**64**	52
Transportation and selling	**55**	61	**29**	23	**-**	-	**84**	84
Operating	**191**	156	**191**	153	**3**	3	**385**	312
Operating Cash Flow	**$ 1,517**	$ 1,371	**$ 1,328**	$ 699	**$ 5**	$ 6	**$ 2,850**	$ 2,076

Canadian Foothills

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 2,891**	$ 2,352	**$ 494**	$ 268	**$ 47**	$ 42	**$ 3,432**	$ 2,662
Expenses								
Production and mineral taxes	**26**	32	**4**	2	**-**	-	**30**	34
Transportation and selling	**158**	142	**9**	7	**-**	-	**167**	149
Operating	**432**	345	**30**	23	**16**	15	**478**	383
Operating Cash Flow	**$ 2,275**	$ 1,833	**$ 451**	$ 236	**$ 31**	$ 27	**$ 2,757**	$ 2,096

United States

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 3,754**	$ 2,754	**$ 353**	$ 210	**$ 249**	$ 230	**$ 4,356**	$ 3,194
Expenses								
Production and mineral taxes	**280**	127	**31**	15	**-**	-	**311**	142
Transportation and selling	**367**	220	**-**	-	**-**	-	**367**	220
Operating	**266**	228	**-**	-	**216**	213	**482**	441
Operating Cash Flow	**$ 2,841**	$ 2,179	**$ 322**	$ 195	**$ 33**	$ 17	**$ 3,196**	$ 2,391

Integrated Oil

	Oil		Downstream Refining		Other *		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 898**	$ 552	**$ 7,514**	$ 5,109	**$ 100**	$ 170	**$ 8,512**	$ 5,831
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**1**	-	**1**	-
Transportation and selling	**380**	258	**-**	-	**8**	11	**388**	269
Operating	**133**	123	**375**	317	**57**	48	**565**	488
Purchased product	**-**	-	**6,800**	3,898	**(126)**	(61)	**6,674**	3,837
Operating Cash Flow	**$ 385**	$ 171	**$ 339**	$ 894	**$ 160**	$ 172	**$ 884**	$ 1,237

* Includes exploration and production of natural gas and bitumen from the Athabasca and Senlac properties.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

The following tables represent EnCana and Cenovus' operating information, post-Arrangement (See Note 4), giving effect to the realigned reporting hierarchies described previously in this note, excluding their respective share of the Market Optimization and Corporate segments.

EnCana's operating segments, post-Arrangement, will include Canadian Foothills, United States and Offshore and International. Cenovus' operating segments, post-Arrangement, will include Canadian Plains and Integrated Oil.

Results of Operations (For the three months ended September 30)

Operating Information

EnCana

	Canadian Foothills		United States		Offshore & International		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,168**	$ 881	**$ 1,477**	$ 1,103	**$ -**	$ 1	**$ 2,645**	$ 1,985
Expenses								
Production and mineral taxes	**14**	10	**97**	52	**-**	-	**111**	62
Transportation and selling	**57**	51	**132**	77	**-**	-	**189**	128
Operating	**120**	129	**127**	140	**(6)**	-	**241**	269
Operating Cash Flow	**$ 977**	$ 691	**$ 1,121**	$ 834	**$ 6**	$ 1	**$ 2,104**	$ 1,526

Cenovus

	Canadian Plains		Integrated Oil		Total	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,139**	$ 824	**$ 3,085**	$ 2,265	**$ 4,224**	$ 3,089
Expenses						
Production and mineral taxes	**27**	17	**-**	-	**27**	17
Transportation and selling	**32**	26	**139**	66	**171**	92
Operating	**96**	103	**173**	147	**269**	250
Purchased product	**-**	-	**2,634**	1,584	**2,634**	1,584
Operating Cash Flow	**$ 984**	$ 678	**$ 139**	$ 468	**$ 1,123**	$ 1,146

Results of Operations (For the nine months ended September 30)

Operating Information

EnCana

	Canadian Foothills		United States		Offshore & International		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 3,432**	$ 2,662	**$ 4,356**	$ 3,194	**$ 1**	$ -	**$ 7,789**	$ 5,856
Expenses								
Production and mineral taxes	**30**	34	**311**	142	**-**	-	**341**	176
Transportation and selling	**167**	149	**367**	220	**-**	-	**534**	369
Operating	**478**	383	**482**	441	**(5)**	2	**955**	826
Operating Cash Flow	**$ 2,757**	$ 2,096	**$ 3,196**	$ 2,391	**$ 6**	$ (2)	**$ 5,959**	$ 4,485

Cenovus

	Canadian Plains		Integrated Oil		Total	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 3,383**	$ 2,524	**$ 8,512**	$ 5,831	**$ 11,895**	$ 8,355
Expenses						
Production and mineral taxes	**64**	52	**1**	-	**65**	52
Transportation and selling	**84**	84	**388**	269	**472**	353
Operating	**385**	312	**565**	488	**950**	800
Purchased product	**-**	-	**6,674**	3,837	**6,674**	3,837
Operating Cash Flow	**$ 2,850**	$ 2,076	**$ 884**	$ 1,237	**$ 3,734**	$ 3,313

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Capital Expenditures

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	**2008**	2007
Capital				
Canadian Plains	**$ 173**	$ 218	**$ 593**	$ 558
Canadian Foothills	**458**	727	**1,795**	1,779
United States	**621**	452	**1,800**	1,313
Integrated Oil	**275**	154	**804**	424
Offshore & International	**12**	13	**65**	75
Market Optimization	**4**	2	**11**	5
Corporate	**45**	9	**87**	76
	1,588	1,575	**5,155**	4,230
Acquisition Capital				
Canadian Foothills	**7**	60	**99**	67
United States	**850**	15	**1,094**	18
Integrated Oil	**-**	-	**-**	14
Offshore & International	**21**	-	**21**	-
	878	75	**1,214**	99
Total	**$ 2,466**	$ 1,650	**$ 6,369**	$ 4,329

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes.

Pursuant to the agreements with Brown Haynesville and Brown Southwest, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The arrangements with Brown Haynesville and Brown Southwest will be completed on March 24, 2009 and January 19, 2009 respectively and the assets will be transferred to EnCana at that time. EnCana has determined that each relationship with Brown Haynesville and Brown Southwest represents an interest in a Variable Interest Entity ("VIE") and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Haynesville and Brown Southwest from the dates of acquisition.

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately $2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC ("Brown Kilgore"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Kilgore represented an interest in a VIE from November 20, 2007 to May 18, 2008. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Kilgore. On May 18, 2008, when the arrangement with Brown Kilgore was completed, the assets were transferred to EnCana.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Property, Plant and Equipment and Total Assets by Segment

	Property, Plant and Equipment		Total Assets	
	As at		As at	
	September 30, 2008	December 31, 2007	**September 30, 2008**	December 31, 2007
Canadian Plains	**$ 6,355**	$ 6,967	**$ 7,933**	$ 8,626
Canadian Foothills	**10,216**	10,127	**12,142**	12,184
United States	**13,394**	11,879	**14,535**	12,948
Integrated Oil	**5,573**	5,164	**10,609**	10,122
Offshore & International	**1,096**	1,104	**1,268**	1,135
Market Optimization	**159**	171	**677**	478
Corporate	**581**	453	**3,332**	1,481
Total	**$ 37,374**	$ 35,865	**$ 50,496**	$ 46,974

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third party developer. As at September 30, 2008, Corporate Property, Plant and Equipment and Total Assets includes EnCana's accrual to date of $248 million ($147 million at December 31, 2007) related to this office project as an asset under construction.

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre ("PFC") for the Deep Panuke project. As at September 30, 2008, Offshore and International Property, Plant, and Equipment and Total Assets includes EnCana's accrual to date of $128 million related to this offshore facility as an asset under construction.

Corresponding liabilities for these projects are included in Other Liabilities in the Consolidated Balance Sheet. There is no effect on the Company's net earnings or cash flows related to the capitalization of The Bow office project or the Deep Panuke PFC.

6. DIVESTITURES

Total year-to-date proceeds received on sale of assets and investments were $593 million (2007 - $505 million) as described below:

Canadian Plains, Canadian Foothills and United States

In 2008, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of $39 million (2007 - nil) in Canadian Plains, $218 million (2007 - $55 million) in Canadian Foothills, and $123 million (2007 - $11 million) in the United States.

Offshore and International

In September 2008, the Company completed the sale of its interests in Brazil for net proceeds of $164 million resulting in a gain on sale of $124 million. After recording income tax of $25 million, EnCana recorded an after-tax gain of $99 million.

In August 2007, the Company closed the sale of its Australia assets for proceeds of $31 million resulting in a gain on sale of $30 million. After recording income tax of $5 million, EnCana recorded an after-tax gain of $25 million.

In May 2007, the Company completed the sale of its assets in the Mackenzie Delta and Beaufort Sea for proceeds of $159 million, which were credited to property, plant and equipment.

In January 2007, the Company completed the sale of its interests in Chad, properties that were in the pre-production stage, for proceeds of $208 million which resulted in a gain on sale of $59 million.

Corporate

In February 2007, the Company sold The Bow office project assets for proceeds of approximately $57 million, representing its investment at the date of sale. Refer to Note 5 for further discussion of The Bow office project assets.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

7. INTEREST, NET

	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Interest Expense - Long-Term Debt	**$ 142**	$ 113	**$ 426**	$ 331
Interest Expense - Other *	**56**	72	**166**	178
Interest Income *	**(51)**	(83)	**(164)**	(212)
	$ 147	$ 102	**$ 428**	$ 297

* Interest Expense - Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively.

8. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**$ 205**	$ (278)	**$ 370**	$ (608)
Translation of U.S. dollar partnership contribution receivable issued from Canada	**(119)**	252	**(218)**	595
Other Foreign Exchange (Gain) Loss	**24**	100	**18**	82
	$ 110	$ 74	**$ 170**	$ 69

9. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Current				
Canada	**$ 40**	$ 142	**$ 446**	$ 485
United States	**-**	172	**385**	484
Other Countries	**25**	-	**38**	5
Total Current Tax	**65**	314	**869**	974
Future	**1,418**	102	**1,491**	(9)
	$ 1,483	$ 416	**$ 2,360**	$ 965

Included in current tax for 2008 is $25 million related to the sale of assets in Brazil (2007 - nil).

The following table reconciles income taxes calculated at the Canadian statutory rate with the actual income taxes:

	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Net Earnings Before Income Tax	**$ 5,036**	$ 1,350	**$ 7,227**	$ 3,842
Canadian Statutory Rate	**29.7%**	32.3%	**29.7%**	32.3%
Expected Income Tax	**1,494**	436	**2,144**	1,241
Effect on Taxes Resulting from:				
Statutory and other rate differences	**119**	12	**197**	36
Effect of tax rate changes*	**-**	-	**-**	(37)
Effect of legislative changes	**-**	-	**-**	(231)
Non-taxable downstream partnership income	**(3)**	(21)	**(10)**	(40)
International financing	**(74)**	(16)	**(233)**	(45)
Foreign exchange (gains) losses not included in net earnings	**(39)**	-	**141**	-
Non-taxable capital (gains) losses	**19**	(32)	**30**	(44)
Other	**(33)**	37	**91**	85
	$ 1,483	$ 416	**$ 2,360**	$ 965
Effective Tax Rate	**29.4%**	30.8%	**32.7%**	25.1%

* The Canadian federal government, during the second quarter of 2007, enacted income tax rate changes.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

10. INVENTORIES

	As at September 30, 2008	As at December 31, 2007
Product		
Canadian Plains	**$ 1**	$ -
United States	**3**	2
Integrated Oil	**978**	646
Market Optimization	**294**	180
Parts and Supplies	**4**	-
	$ 1,280	$ 828

11. LONG-TERM DEBT

	As at September 30, 2008	As at December 31, 2007
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 1,576**	$ 1,506
Unsecured notes	**1,179**	1,138
	2,755	2,644
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**574**	495
Unsecured notes	**6,350**	6,421
	6,924	6,916
Increase in Value of Debt Acquired *	**57**	66
Debt Discounts and Financing Costs	**(79)**	(83)
Current Portion of Long-Term Debt	**(250)**	(703)
	$ 9,407	$ 8,840

* Certain of the notes and debentures of EnCana were acquired in business combinations and were accounted for at their fair value at the dates of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 20 years.

On January 18, 2008, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C$750 million. The notes have a coupon rate of 5.80 percent and mature on January 18, 2018.

12. ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas assets and refining facilities:

	As at September 30, 2008	As at December 31, 2007
Asset Retirement Obligation, Beginning of Year	**$ 1,458**	$ 1,051
Liabilities Incurred	**42**	89
Liabilities Settled	**(96)**	(100)
Liabilities Divested	**(6)**	-
Change in Estimated Future Cash Flows	**(5)**	184
Accretion Expense	**61**	64
Other	**(80)**	170
Asset Retirement Obligation, End of Period	**$ 1,374**	$ 1,458

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. SHARE CAPITAL

(millions)	September 30, 2008 Number		September 30, 2008 Amount	December 31, 2007 Number		December 31, 2007 Amount
Common Shares Outstanding, Beginning of Year	**750.2**	**$**	**4,479**	777.9	$	4,587
Common Shares Issued under Option Plans	**2.9**		**78**	8.3		176
Stock-Based Compensation	**-**		**11**	-		17
Common Shares Purchased	**(2.8)**		**(13)**	(36.0)		(301)
Common Shares Outstanding, End of Period	**750.3**	**$**	**4,555**	750.2	$	4,479

Normal Course Issuer Bid

To September 30, 2008, the Company purchased 4.8 million Common Shares for total consideration of approximately $326 million. Of the amount paid, $29 million was charged to Share capital and $297 million was charged to Retained earnings. Included in the Common Shares Purchased in 2008 are 2.0 million Common Shares distributed (2007 - 2.9 million), valued at $16 million (2007 - $24 million), from the EnCana Employee Benefit Plan Trust that vested under EnCana's Performance Share Unit Plan (See Note 15). For these Common Shares distributed, there was a $54 million adjustment to Retained earnings (2007 - $82 million) with a reduction to Paid in surplus of $70 million (2007 - $106 million).

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under six consecutive Normal Course Issuer Bids ("Bids"). EnCana is entitled to purchase, for cancellation, up to approximately 75.1 million Common Shares under the renewed Bid which commenced on November 13, 2007 and terminates on November 12, 2008.

Stock Options

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the date granted. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted.

The following tables summarize the information about options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSARs") attached to them at September 30, 2008. Information related to TSARs is included in Note 15.

	Stock Options *(millions)*	**Weighted Average Exercise Price *(C$)***
Outstanding, Beginning of Year	**3.4**	**21.82**
Exercised	**(2.8)**	**23.68**
Outstanding, End of Period	**0.6**	**12.40**
Exercisable, End of Period	**0.6**	**12.40**

	Outstanding Options			**Exercisable Options**	
Range of Exercise Price (C$)	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *(C$)*
11.00 to 21.99	0.5	1.1	11.62	0.5	11.62
22.00 to 25.99	0.1	0.2	24.19	0.1	24.19
	0.6	1.1	12.40	0.6	12.40

At December 31, 2007, the balance in Paid in surplus related to stock-based compensation programs.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. CAPITAL STRUCTURE

The Company's capital structure is comprised of Shareholders' Equity plus Long-Term Debt. The Company's objectives when managing its capital structure are to:

i) maintain financial flexibility so as to preserve EnCana's access to capital markets and its ability to meet its financial obligations; and
ii) finance internally generated growth as well as potential acquisitions.

The Company monitors its capital structure and short-term financing requirements using non-GAAP financial metrics consisting of Net Debt to Capitalization and Net Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward the Company's overall debt position as measures of the Company's overall financial strength.

EnCana targets a Net Debt to Capitalization ratio of between 30 and 40 percent that is calculated as follows:

	As at	
	September 30, 2008	December 31, 2007
Long-Term Debt, excluding current portion	**$ 9,407**	$ 8,840
Less: Working capital	**1,041**	(1,886)
Net Debt	**8,366**	10,726
Total Shareholders' Equity	**23,643**	20,704
Total Capitalization	**$ 32,009**	$ 31,430
Net Debt to Capitalization ratio	**26%**	34%

EnCana's Net Debt to Capitalization ratio decreased to 26 percent from 34 percent at December 31, 2007 primarily due to unrealized mark-to-market gains on risk management instruments which decreased Net Debt. Excluding this impact to working capital, the Net Debt to Capitalization ratio would have been 29 percent at September 30, 2008 and would have remained unchanged at 34 percent at December 31, 2007.

EnCana targets a Net Debt to Adjusted EBITDA of 1.0 to 2.0 times. At September 30, 2008, the Net Debt to Adjusted EBITDA was 0.6x (December 31, 2007 - 1.2x) calculated on a trailing twelve-month basis as follows:

	As at	
	September 30, 2008	December 31, 2007
Net Debt	**$ 8,366**	$ 10,726
Net Earnings from Continuing Operations	**$ 5,874**	$ 3,884
Add (deduct):		
Interest, net	**559**	428
Income tax expense	**2,332**	937
Depreciation, depletion and amortization	**4,313**	3,816
Accretion of asset retirement obligation	**79**	64
Foreign exchange (gain) loss, net	**(63)**	(164)
(Gain) loss on divestitures	**(119)**	(65)
Adjusted EBITDA	**$ 12,975**	$ 8,900
Net Debt to Adjusted EBITDA	**0.6x**	1.2x

EnCana manages its capital structure and makes adjustments according to market conditions to maintain flexibility while achieving the objectives stated above. To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt or repay existing debt.

The Company's capital management objectives, evaluation measures, definitions and targets have remained unchanged over the periods presented. EnCana is subject to certain financial covenants in its credit facility agreements and is in compliance with all financial covenants.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

15. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at September 30, 2008. Additional information is contained in Note 17 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2007.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	**2008**	2007
Current Service Cost	**$ 4**	$ 3	**$ 12**	$ 11
Interest Cost	**5**	5	**16**	14
Expected Return on Plan Assets	**(4)**	(5)	**(14)**	(14)
Expected Actuarial Loss on Accrued Benefit Obligation	**1**	1	**3**	3
Expected Amortization of Past Service Costs	**-**	-	**1**	1
Amortization of Transitional Obligation	**-**	-	**(1)**	(1)
Expense for Defined Contribution Plan	**10**	9	**30**	25
Net Benefit Plan Expense	**$ 16**	$ 13	**$ 47**	$ 39

For the period ended September 30, 2008, contributions of $8 million have been made to the defined benefit pension plans (2007 - $8 million).

B) Tandem Share Appreciation Rights ("TSARs")

The following table summarizes the information about TSARs at September 30, 2008:

	Outstanding TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**18,854,141**	**48.44**
Granted	**4,257,572**	**70.67**
Exercised - SARs	**(3,003,715)**	**43.85**
Exercised - Options	**(70,286)**	**42.53**
Forfeited	**(466,309)**	**54.57**
Outstanding, End of Period	**19,571,403**	**53.85**
Exercisable, End of Period	**8,422,211**	**46.01**

For the period ended September 30, 2008, EnCana recorded compensation costs of $68 million related to the outstanding TSARs (2007 - $140 million).

C) Performance Tandem Share Appreciation Rights ("Performance TSARs")

The following table summarizes the information about Performance TSARs at September 30, 2008:

	Outstanding TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**6,930,925**	**56.09**
Granted	**7,058,538**	**69.40**
Exercised - SARs	**(279,378)**	**56.09**
Exercised - Options	**(4,613)**	**56.09**
Forfeited	**(601,046)**	**59.10**
Outstanding, End of Period	**13,104,426**	**63.12**
Exercisable, End of Period	**1,476,150**	**56.09**

For the period ended September 30, 2008, EnCana recorded compensation costs of $42 million related to the outstanding Performance TSARs (2007 - $9 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

15. COMPENSATION PLANS (continued)

D) Share Appreciation Rights ("SARs")

In 2008, EnCana granted SARs to certain employees which entitles the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the grant price. SARs are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the grant date.

The following table summarizes the information about SARs at September 30, 2008:

	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	-	-
Granted	1,260,315	72.85
Forfeited	(21,725)	69.40
Outstanding, End of Period	1,238,590	72.91
Exercisable, End of Period	-	-

For the period ended September 30, 2008, EnCana has not recorded any compensation costs related to the outstanding SARs (2007 - nil).

E) Performance Share Appreciation Rights ("Performance SARs")

In 2008, EnCana granted Performance SARs to certain employees which entitles the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the grant price. Performance SARs vest and expire under the same terms and service conditions as SARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance SARs that do not vest when eligible are forfeited.

The following table summarizes the information about Performance SARs at September 30, 2008:

	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	-	-
Granted	1,677,030	69.40
Forfeited	(43,450)	69.40
Outstanding, End of Period	1,633,580	69.40
Exercisable, End of Period	-	-

For the period ended September 30, 2008, EnCana has not recorded any compensation costs related to the outstanding Performance SARs (2007 - nil).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

15. COMPENSATION PLANS (continued)

F) Deferred Share Units ("DSUs")

The following table summarizes the information about DSUs at September 30, 2008:

	Outstanding DSUs
Canadian Dollar Denominated *(C$)*	
Outstanding, Beginning of Year	**589,174**
Granted, Directors	**83,344**
Redeemed	**(34,008)**
Units, in Lieu of Dividends	**10,254**
Outstanding, End of Period	**648,764**

For the period ended September 30, 2008, EnCana recorded compensation costs of $7 million related to the outstanding DSUs (2007 - $10 million).

G) Performance Share Units ("PSUs")

The following table summarizes the information about PSUs at September 30, 2008:

	Outstanding PSUs	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**1,685,036**	**38.79**
Granted	**408,686**	**70.77**
Distributed	**(2,042,541)**	**45.34**
Forfeited	**(51,181)**	**38.32**
Outstanding, End of Period	**-**	**-**

For the period ended September 30, 2008, EnCana recorded compensation costs of $1 million related to the outstanding PSUs (2007 - $18 million).

16. PER SHARE AMOUNTS

The following table summarizes the Common Shares used in calculating Net Earnings per Common Share:

	Three Months Ended				Nine Months Ended	
	March 31,	June 30,	September 30,		September 30,	
(millions)	2008	2008	**2008**	2007	**2008**	2007
Weighted Average Common Shares Outstanding - Basic	749.5	750.2	**750.3**	750.4	**750.0**	759.1
Effect of Dilutive Securities	3.5	1.1	**1.0**	5.5	**2.0**	8.4
Weighted Average Common Shares Outstanding - Diluted	753.0	751.3	**751.3**	755.9	**752.0**	767.5

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

EnCana's financial assets and liabilities are comprised of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, the partnership contribution receivable and payable, risk management assets and liabilities, and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

A) Fair Value of Financial Assets and Liabilities

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments.

Risk management assets and liabilities are recorded at their estimated fair value based on the mark-to-market method of accounting, using quoted market prices or, in their absence, third-party market indications and forecasts. Long-term debt is carried at amortized cost using the effective interest method of amortization. The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates expected to be available to the Company at period end.

The fair values of the partnership contribution receivable and partnership contribution payable approximate their carrying amount due to the specific nature of these instruments in relation to the creation of the integrated oil joint venture. Further information about these notes is disclosed in Note 10 to the Company's annual audited Consolidated Financial Statements.

The fair value of financial assets and liabilities were as follows:

	As at September 30, 2008		As at December 31, 2007	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Held-for-Trading:				
Cash and cash equivalents	**$ 622**	**$ 622**	$ 553	$ 553
Risk management assets *	**2,037**	**2,037**	403	403
Loans and Receivables:				
Accounts receivable and accrued revenues	**2,473**	**2,473**	2,381	2,381
Partnership contribution receivable *	**3,223**	**3,223**	3,444	3,444
Financial Liabilities				
Held-for-Trading:				
Risk management liabilities *	**$ 74**	**$ 74**	$ 236	$ 236
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**4,027**	**4,027**	3,982	3,982
Long-term debt *	**9,657**	**8,891**	9,543	9,763
Partnership contribution payable *	**3,237**	**3,237**	3,451	3,451

* Including current portion.

B) Risk Management Assets and Liabilities

Net Risk Management Position	**As at September 30, 2008**	As at December 31, 2007
Risk Management		
Current asset	**$ 1,578**	$ 385
Long-term asset	**459**	18
	2,037	403
Risk Management		
Current liability	**74**	207
Long-term liability	**-**	29
	74	236
Net Risk Management Asset (Liability)	**$ 1,963**	$ 167

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

B) Risk Management Assets and Liabilities (continued)

Summary of Unrealized Risk Management Positions

	As at September 30, 2008			As at December 31, 2007		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Natural gas	$ 1,990	$ -	$ 1,990	$ 375	$ 29	$ 346
Crude oil	24	74	(50)	6	205	(199)
Power	23	-	23	19	-	19
Interest Rates	-	-	-	2	-	2
Credit	-	-	-	1	2	(1)
Total Fair Value	$ 2,037	$ 74	$ 1,963	$ 403	$ 236	$ 167

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

	As at September 30, 2008	As at December 31, 2007
Prices actively quoted	$ 916	$ 105
Prices sourced from observable data or market corroboration	1,047	62
Total Fair Value	$ 1,963	$ 167

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

Net Fair Value of Commodity Price Positions at September 30, 2008

	Notional Volumes	Term	Average Price	Fair Market Value
Natural Gas Sales Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	1,948 MMcf/d	2008	8.86 US$/Mcf	$ 230
NYMEX Fixed Price	1,618 MMcf/d	2009	9.31 US$/Mcf	732
NYMEX Fixed Price	27 MMcf/d	2010	9.25 US$/Mcf	2
Purchased Options				
AECO Call	(10) MMcf/d	2008	9.54 C$/Mcf	-
NYMEX Call	(578) MMcf/d	2008	11.50 US$/Mcf	(30)
NYMEX Call	(150) MMcf/d	2009	11.67 US$/Mcf	(14)
NYMEX Put	411 MMcf/d	2008	9.10 US$/Mcf	49
NYMEX Put	516 MMcf/d	2009	9.10 US$/Mcf	231
Basis Contracts				
Canada	135 MMcf/d	2008	(0.72) US$/Mcf	7
United States	1,393 MMcf/d	2008	(0.85) US$/Mcf	188
Canada and United States *		2009-2013		435
				1,830
Other Financial Positions **				2
Total Unrealized Gain on Financial Contracts				1,832
Paid Premiums on Unexpired Options				158
Natural Gas Fair Value Position				$ 1,990

* EnCana has entered into swaps to protect against widening natural gas price differentials between production areas, including Canada, the U.S. Rockies and Texas, and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

** Other financial positions are part of the ongoing operations of the Company's proprietary production and transportation commitment management.

Notes to Consolidated Financial Statements *(unaudited)*
(All amounts in $ millions unless otherwise specified)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

B) Risk Management Assets and Liabilities (continued)

Net Fair Value of Commodity Price Positions at September 30, 2008 (continued)

	Notional Volumes	Term	Average Price	Fair Market Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	23,000 bbls/d	2008	70.13 US$/bbl	$ (64)
Other Financial Positions **				14
Crude Oil Fair Value Position				$ (50)

** Other financial positions are part of the ongoing operations of the Company's proprietary production management and its share of downstream refining positions.

Power Purchase Contracts	
Power Fair Value Position	$ 23

Net Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Realized Gain (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	**2008**	2007
Revenues, Net of Royalties	**$ (389)**	$ 496	**$ (955)**	$ 1,193
Operating Expenses and Other	**(2)**	3	**(2)**	4
Gain (Loss) on Risk Management	**$ (391)**	$ 499	**$ (957)**	$ 1,197

	Unrealized Gain (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	**2008**	2007
Revenues, Net of Royalties	**$ 3,057**	$ (107)	**$ 1,633**	$ (673)
Operating Expenses and Other	**(7)**	-	**6**	7
Gain (Loss) on Risk Management	**$ 3,050**	$ (107)	**$ 1,639**	$ (666)

Reconciliation of Unrealized Risk Management Positions from January 1 to September 30, 2008

	2008		2007
	Fair Market Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 167**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**682**	**$ 682**	$ 520
Fair Value of Contracts in Place at Transition that Expired During the Period	**-**	**-**	11
Foreign Exchange Loss on Canadian Dollar Contracts	**(1)**	**-**	-
Fair Value of Contracts Realized During the Period	**957**	**957**	(1,197)
Fair Value of Contracts Outstanding	**$ 1,805**	**$ 1,639**	$ (666)
Paid Premiums on Unexpired Options	**158**		
Fair Value of Contracts and Premiums Paid, End of Period	**$ 1,963**		

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

B) Risk Management Assets and Liabilities (continued)

Commodity Price Sensitivities

The following table summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Company believes 10% volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting net earnings as at September 30, 2008 as follows:

	Favorable 10% Change	Unfavorable 10% Change
Natural gas price	$ 664	$ (638)
Crude oil price	21	(21)
Power price	7	(7)

C) Risks Associated with Financial Assets and Liabilities

The Company is exposed to financial risks arising from its financial assets and liabilities. The financial risks include market risk relating to commodity prices, interest rates and foreign exchange rates, credit risk and liquidity risk.

Market Risk

Market risk, the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices, is comprised of the following:

- **Commodity Price Risk**
  As a means of mitigating exposure to commodity price risk volatility, the Company has entered into various financial derivative agreements. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is to not use derivative financial instruments for speculative purposes.

  Natural Gas - To partially mitigate the natural gas commodity price risk, the Company enters into option contracts and swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points.

  Crude Oil - The Company has partially mitigated its exposure to the WTI NYMEX price with fixed price swaps.

  Power - The Company has in place two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

- **Interest Rate Risk**
  The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

  At September 30, 2008, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $15 million.

- **Foreign Exchange Risk**
  As EnCana operates primarily in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on the Company's reported results. EnCana's functional currency is Canadian dollars, however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations are not separately identifiable.

  To mitigate the exposure to the fluctuating U.S./Canadian exchange rate, EnCana maintains a mix of both U.S. dollar and Canadian dollar debt.

  As disclosed in Note 8, EnCana's foreign exchange (gain) loss is primarily comprised of unrealized foreign exchange gains and losses on the translation of U.S. dollar debt issued from Canada and the translation of U.S. dollar partnership contribution receivable issued from Canada. At September 30, 2008, EnCana had $5,350 million in U.S. dollar debt issued from Canada ($5,421 million at December 31, 2007) and $3,223 million related to the U.S. dollar partnership contribution receivable ($3,444 million at December 31, 2007). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $20 million change in foreign exchange (gain) loss at September 30, 2008.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

C) Risks Associated with Financial Assets and Liabilities (continued)

Credit Risk

Credit risk is the risk that the counterparty to a financial asset will default resulting in the Company incurring a financial loss. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks.

At September 30, 2008, EnCana had three counterparties whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the partnership contribution receivable is the total carrying value.

Liquidity Risk

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company manages its liquidity risk through cash and debt management. As disclosed in Note 14, EnCana targets a Net Debt to Capitalization ratio between 30 and 40 percent and a Net Debt to Adjusted EBITDA of 1.0 to 2.0 times to steward the Company's overall debt position.

In managing liquidity risk, the Company has access to a wide range of funding at competitive rates through commercial paper, capital markets and banks. As at September 30, 2008, EnCana had available unused committed bank credit facilities in the amount of $2.7 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.2 billion. The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the announcement of the proposed Arrangement (See Note 4), Standard & Poor's Ratings Service assigned a rating of A- and placed the Company on "CreditWatch with Negative Implications", DBRS Limited assigned a rating of A(low) and placed the Company "Under Review with Developing Implications", and Moody's Investors Service has assigned a rating of Baa2 and changed the outlook to "Stable" from "Positive".

The timing of cash outflows relating to financial liabilities are outlined in the table below:

	1 year	2 - 3 years	4 - 5 years	beyond 5 years	Total
Accounts payable and accrued liabilities	$ 4,027	$ -	$ -	$ -	$ 4,027
Risk management liabilities	74	-	-	-	74
Long-term debt *	250	200	3,122	6,107	9,679
Partnership contribution payable *	301	660	743	1,533	3,237

* Principal, including current portion.

Included in EnCana's total long-term debt obligations of $9,679 million at September 30, 2008 are $2,150 million in obligations related to Bankers' Acceptances, Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 - 5 years.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

18. CONTINGENCIES

Legal Proceedings

The Company is involved in various legal claims associated with the normal course of operations. The Company believes it has made adequate provision for such legal claims.

Discontinued Merchant Energy Operations

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court for payment of $20.5 million and $2.4 million, respectively. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") for $20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million. Also, without admitting any liability whatsoever, WD concluded settlement negotiations with a group of individual plaintiffs. It was agreed that WD would settle these claims for $23 million. Execution of the Settlement Agreement is pending.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against this outstanding claim; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

19. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2008.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2008				2007				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
TOTAL CONSOLIDATED									
Cash Flow [1]	**8,087**	**2,809**	2,889	2,389	8,453	1,934	2,218	2,549	1,752
Per share - Basic	**10.78**	**3.74**	3.85	3.19	11.17	2.58	2.96	3.36	2.28
- Diluted	**10.75**	**3.74**	3.85	3.17	11.06	2.56	2.93	3.33	2.25
Net Earnings	**4,867**	**3,553**	1,221	93	3,959	1,082	934	1,446	497
Per share - Basic	**6.49**	**4.74**	1.63	0.12	5.23	1.44	1.24	1.91	0.65
- Diluted	**6.47**	**4.73**	1.63	0.12	5.18	1.43	1.24	1.89	0.64
Operating Earnings [2]	**3,956**	**1,442**	1,469	1,045	4,100	849	1,032	1,369	850
Per share - Diluted	**5.26**	**1.92**	1.96	1.39	5.36	1.12	1.37	1.79	1.09
CONTINUING OPERATIONS									
Cash Flow from Continuing Operations [3]	**8,087**	**2,809**	2,889	2,389	8,453	1,934	2,218	2,549	1,752
Net Earnings from Continuing Operations	**4,867**	**3,553**	1,221	93	3,884	1,007	934	1,446	497
Per share - Basic	**6.49**	**4.74**	1.63	0.12	5.13	1.34	1.24	1.91	0.65
- Diluted	**6.47**	**4.73**	1.63	0.12	5.08	1.33	1.24	1.89	0.64
Operating Earnings - Continuing Operations [4]	**3,956**	**1,442**	1,469	1,045	4,100	849	1,032	1,369	850
Effective Tax Rates using									
Net Earnings	**32.7%**				19.4%				
Operating Earnings, excluding divestitures	**29.5%**				28.6%				
Canadian Statutory Rate	**29.7%**				32.3%				
Foreign Exchange Rates *(US$ per C$1)*									
Average	**0.982**	**0.961**	0.990	0.996	0.930	1.019	0.957	0.911	0.854
Period end	**0.944**	**0.944**	0.982	0.973	1.012	1.012	1.004	0.940	0.867
CASH FLOW INFORMATION									
Cash from Operating Activities	**6,812**	**3,058**	1,996	1,758	8,429	2,193	2,180	2,148	1,908
Deduct (Add back):									
Net change in other assets and liabilities	**(283)**	**(19)**	(171)	(93)	(16)	(21)	1	(16)	20
Net change in non-cash working capital	**(992)**	**268**	(722)	(538)	(8)	280	(39)	(385)	136
Cash Flow [1]	**8,087**	**2,809**	2,889	2,389	8,453	1,934	2,218	2,549	1,752

(1) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.

(2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates.

(3) Cash Flow from Continuing Operations is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations, net change in non-cash working capital from discontinued operations and cash flow from discontinued operations.

(4) Operating Earnings - Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding the after-tax gain/loss on discontinuance, the after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics (continued)

($ millions, except per share amounts)

Common Share Information	2008				2007				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*									
Period end	**750.3**	**750.3**	750.2	750.0	750.2	750.2	749.5	752.8	761.3
Average - Basic	**750.0**	**750.3**	750.2	749.5	756.8	749.8	750.4	758.5	768.4
Average - Diluted	**752.0**	**751.3**	751.3	753.0	764.6	755.1	755.9	765.2	779.6
Price Range *($ per share)*									
TSX - C$									
High	**97.81**	**95.91**	97.81	79.26	71.21	69.59	67.99	71.21	59.65
Low	**59.95**	**63.84**	76.41	59.95	51.55	60.89	59.33	57.61	51.55
Close	**67.96**	**67.96**	93.36	78.20	67.50	67.50	61.50	65.52	58.40
NYSE - US$									
High	**99.36**	**94.41**	99.36	79.75	75.85	75.85	65.18	66.87	51.49
Low	**58.13**	**61.13**	74.16	58.13	42.38	60.86	55.13	50.58	42.38
Close	**65.73**	**65.73**	90.93	75.75	67.96	67.96	61.85	61.45	50.63
Dividends Paid *($ per share)*	**1.20**	**0.40**	0.40	0.40	0.80	0.20	0.20	0.20	0.20
Share Volume Traded *(millions)*	**1,278.8**	**547.7**	376.4	354.7	1,250.9	290.8	301.4	327.4	331.3
Share Value Traded *(US$ millions weekly average)*	**2,439.0**	**2,912.5**	2,486.0	1,900.5	1,390.9	1,489.3	1,414.4	1,479.5	1,209.5

Financial Metrics	2008	2007
Net Debt to Capitalization	**26%**	34%
Net Debt to Adjusted EBITDA *	**0.6x**	1.2x
Return on Capital Employed	**21%**	15%
Return on Common Equity	**27%**	21%

* Calculated on a trailing twelve-month basis.

Net Capital Investment *($ millions)*	**2008**	2007
Capital		
Canadian Plains	**$ 593**	$ 558
Canadian Foothills	**1,795**	1,779
United States	**1,800**	1,313
Integrated Oil	**804**	424
Offshore & International	**65**	75
Market Optimization	**11**	5
Corporate [(1)]	**87**	76
Capital	**5,155**	4,230
Acquisitions		
Property		
Canadian Foothills	**99**	67
United States [(2)]	**1,094**	18
Integrated Oil	**-**	14
Offshore & International	**21**	-
Divestitures		
Property		
Canadian Plains	**(39)**	-
Canadian Foothills	**(218)**	(55)
United States	**(123)**	(11)
Integrated Oil	**(8)**	-
Offshore & International [(3)]	**(41)**	(174)
Corporate [(4)]	**-**	(57)
Corporate		
Offshore & International [(5)]	**(164)**	(208)
Net Acquisition and Divestiture Activity	**621**	(406)
Net Capital Investment	**$ 5,776**	$ 3,824

(1) Includes capital expenditures on The Bow office project.
(2) Mainly includes Haynesville properties.
(3) Consists primarily of the sale of Mackenzie Delta assets which closed May 30, 2007 and sale of Australia assets which closed August 15, 2007.
(4) Sale of EnCana's office building project assets, The Bow, closed February 9, 2007.
(5) Sale of interests in Brazil closed September 18, 2008 and sale of interests in Chad closed January 12, 2007.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties

Production Volumes	**2008**				2007				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*									
Canadian Plains	**849**	**831**	856	860	875	876	858	874	891
Canadian Foothills	**1,299**	**1,351**	1,289	1,256	1,255	1,313	1,280	1,231	1,196
United States	**1,618**	**1,674**	1,629	1,552	1,345	1,464	1,387	1,303	1,222
Integrated Oil - Other	**64**	**61**	67	65	91	69	105	98	91
Total Produced Gas	**3,830**	**3,917**	3,841	3,733	3,566	3,722	3,630	3,506	3,400
Oil and Natural Gas Liquids *(bbls/d)*									
Light and Medium Oil									
Canadian Plains	**30,786**	**30,134**	30,479	31,752	32,156	31,706	32,064	31,740	33,129
Canadian Foothills	**8,486**	**8,217**	8,376	8,867	8,216	8,441	7,978	7,959	8,489
Heavy Oil									
Canadian Plains	**35,763**	**34,655**	34,618	38,029	38,784	38,581	38,647	38,408	39,510
Foster Creek/Christina Lake	**28,542**	**31,547**	24,671	29,376	26,814	27,190	28,740	27,994	23,269
Integrated Oil - Other	**2,930**	**2,273**	3,009	3,514	2,688	3,040	2,235	2,489	2,990
Natural Gas Liquids [(1)]									
Canadian Plains	**1,199**	**1,147**	1,189	1,262	1,260	1,422	1,209	1,206	1,203
Canadian Foothills	**11,588**	**11,730**	11,779	11,256	10,056	10,966	9,932	9,811	9,497
United States	**13,524**	**13,853**	13,482	13,232	14,180	14,791	15,578	13,809	12,503
Total Oil and Natural Gas Liquids	**132,818**	**133,556**	127,603	137,288	134,154	136,137	136,383	133,416	130,590
Total *(MMcfe/d)*	**4,627**	**4,718**	4,607	4,557	4,371	4,539	4,448	4,306	4,184

(1) Natural gas liquids include condensate volumes.

Downstream									
Refinery Operations [(2)]									
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**419**	**412**	437	408	432	439	460	396	433
Crude utilization *(%)*	**93%**	**91%**	97%	90%	96%	97%	102%	88%	96%
Refined products *(Mbbls/d)*	**446**	**438**	464	435	457	465	484	421	457

(2) Represents 100% of the Wood River and Borger refinery operations.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2008				2007				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas - Canadian Plains *($/Mcf)*									
Price	**8.45**	**8.67**	9.50	7.19	6.10	6.21	5.26	6.66	6.25
Production and mineral taxes	**0.14**	**0.17**	0.17	0.06	0.11	0.04	0.13	0.14	0.12
Transportation and selling	**0.24**	**0.24**	0.22	0.25	0.26	0.25	0.25	0.26	0.27
Operating	**0.82**	**0.59**	0.96	0.93	0.69	0.81	0.62	0.69	0.65
Netback	**7.25**	**7.67**	8.15	5.95	5.04	5.11	4.26	5.57	5.21
Produced Gas - Canadian Foothills *($/Mcf)*									
Price	**8.88**	**9.03**	9.94	7.61	6.30	6.44	5.46	6.86	6.46
Production and mineral taxes	**0.07**	**0.09**	0.09	0.03	0.08	0.04	0.08	0.11	0.10
Transportation and selling	**0.44**	**0.43**	0.43	0.47	0.42	0.41	0.41	0.43	0.43
Operating	**1.21**	**0.87**	1.39	1.41	1.05	1.14	0.96	1.02	1.09
Netback	**7.16**	**7.64**	8.03	5.70	4.75	4.85	4.01	5.30	4.84
Produced Gas - United States *($/Mcf)*									
Price	**8.89**	**8.54**	9.93	8.19	5.38	5.03	4.68	5.73	6.24
Production and mineral taxes	**0.63**	**0.56**	0.72	0.62	0.34	0.29	0.38	0.17	0.53
Transportation and selling	**0.83**	**0.86**	0.81	0.81	0.62	0.64	0.60	0.65	0.61
Operating	**0.60**	**0.38**	0.71	0.71	0.65	0.70	0.52	0.71	0.67
Netback	**6.83**	**6.74**	7.69	6.05	3.77	3.40	3.18	4.20	4.43
Produced Gas - Total *($/Mcf)*									
Price	**8.78**	**8.74**	9.83	7.75	5.89	5.83	5.10	6.38	6.32
Production and mineral taxes	**0.32**	**0.31**	0.37	0.28	0.18	0.14	0.21	0.14	0.26
Transportation and selling	**0.56**	**0.57**	0.55	0.56	0.45	0.46	0.44	0.47	0.45
Operating	**0.87**	**0.61**	1.01	1.02	0.82	0.90	0.72	0.83	0.82
Netback	**7.03**	**7.25**	7.90	5.89	4.44	4.33	3.73	4.94	4.79
Natural Gas Liquids - Canadian Plains *($/bbl)*									
Price	**89.56**	**98.35**	96.34	75.09	59.98	73.12	61.29	56.08	46.69
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**-**	**0.01**	-	-	-	-	-	-	-
Netback	**89.56**	**98.34**	96.34	75.09	59.98	73.12	61.29	56.08	46.69
Natural Gas Liquids - Canadian Foothills *($/bbl)*									
Price	**92.69**	**95.49**	101.23	80.80	59.26	73.42	63.06	55.10	42.82
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**1.33**	**1.20**	1.73	1.04	1.14	1.08	2.02	0.83	0.61
Netback	**91.36**	**94.29**	99.50	79.76	58.12	72.34	61.04	54.27	42.21
Natural Gas Liquids - United States *($/bbl)*									
Price	**95.35**	**97.63**	105.73	82.22	59.83	73.45	60.17	55.43	47.77
Production and mineral taxes	**8.37**	**8.19**	9.75	7.13	4.28	6.12	1.95	4.71	4.56
Transportation and selling	**-**	**-**	-	-	0.01	-	0.01	0.01	0.01
Netback	**86.98**	**89.44**	95.98	75.09	55.54	67.33	58.21	50.71	43.20
Natural Gas Liquids - Total *($/bbl)*									
Price	**93.91**	**96.72**	103.29	81.24	59.61	73.42	61.31	55.33	45.66
Production and mineral taxes	**4.28**	**4.25**	4.94	3.63	2.36	3.30	1.13	2.59	2.43
Transportation and selling	**0.59**	**0.53**	0.78	0.46	0.46	0.44	0.76	0.34	0.26
Netback	**89.04**	**91.94**	97.57	77.15	56.79	69.68	59.42	52.40	42.97
Crude Oil - Light and Medium - Canadian Plains *($/bbl)*									
Price	**99.98**	**107.59**	107.08	85.90	56.41	68.78	59.68	52.43	44.81
Production and mineral taxes	**3.78**	**4.70**	3.97	2.72	2.37	2.36	2.16	2.37	2.59
Transportation and selling	**1.28**	**1.41**	1.27	1.16	1.33	1.22	1.39	1.27	1.43
Operating	**11.35**	**9.40**	13.05	11.60	9.20	10.34	8.84	9.10	8.55
Netback	**83.57**	**92.08**	88.79	70.42	43.51	54.86	47.29	39.69	32.24
Crude Oil - Light and Medium - Canadian Foothills *($/bbl)*									
Price	**106.53**	**112.73**	114.28	93.42	64.63	81.51	67.07	57.00	52.31
Production and mineral taxes	**1.61**	**1.65**	2.05	1.16	1.05	1.59	0.76	1.47	0.37
Transportation and selling	**2.24**	**2.12**	2.70	1.92	1.77	1.66	2.16	1.79	1.49
Operating	**13.10**	**10.02**	15.39	13.84	10.84	12.72	11.21	9.31	10.03
Netback	**89.58**	**98.94**	94.14	76.50	50.97	65.54	52.94	44.43	40.42

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2008				2007				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil - Heavy - Canadian Plains *($/bbl)*									
Price	**87.78**	**95.86**	98.65	70.44	43.91	49.52	48.22	40.70	37.22
Production and mineral taxes	**0.02**	**0.07**	(0.10)	0.07	0.05	0.07	0.06	0.06	(0.01)
Transportation and selling	**1.75**	**2.42**	1.60	1.29	1.18	1.13	1.36	1.19	1.03
Operating	**9.63**	**7.62**	11.30	9.93	7.59	9.06	7.27	7.56	6.48
Netback	**76.38**	**85.75**	85.85	59.15	35.09	39.26	39.53	31.89	29.72
Crude Oil - Total - excluding Foster Creek/Christina Lake *($/bbl)*									
Price	**94.53**	**102.66**	103.40	78.82	50.76	59.93	54.68	47.02	41.42
Production and mineral taxes	**1.73**	**2.16**	1.81	1.28	1.09	1.12	1.01	1.16	1.06
Transportation and selling	**1.65**	**2.00**	1.61	1.36	1.32	1.23	1.47	1.31	1.27
Operating	**11.14**	**8.99**	13.00	11.39	9.03	10.52	8.68	8.85	8.06
Netback	**80.01**	**89.51**	86.98	64.79	39.32	47.06	43.52	35.70	31.03
Crude Oil - Heavy - Foster Creek/Christina Lake *($/bbl)*									
Price	**81.64**	**91.21**	93.64	59.67	40.14	45.58	42.86	39.40	33.28
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**2.51**	**2.10**	2.77	2.72	2.88	2.75	2.10	3.62	3.07
Operating [(1)]	**17.69**	**15.53**	21.41	16.62	14.46	14.05	12.55	14.02	17.12
Netback	**61.44**	**73.58**	69.46	40.33	22.80	28.78	28.21	21.76	13.09
Crude Oil - Total *($/bbl)*									
Price	**91.18**	**99.39**	100.99	74.10	47.90	56.23	51.50	44.92	39.19
Production and mineral taxes	**1.28**	**1.54**	1.36	0.96	0.79	0.83	0.74	0.84	0.77
Transportation and selling	**1.87**	**2.03**	1.90	1.69	1.74	1.62	1.64	1.94	1.75
Operating	**12.84**	**10.86**	15.08	12.68	10.49	11.43	9.72	10.27	10.54
Netback	**75.19**	**84.96**	82.65	58.77	34.88	42.35	39.40	31.87	26.13
Total Liquids - Canada *($/bbl)*									
Price	**91.31**	**98.99**	100.97	74.69	48.92	57.92	52.50	45.83	39.50
Production and mineral taxes	**1.14**	**1.37**	1.20	0.86	0.72	0.74	0.66	0.76	0.70
Transportation and selling	**1.80**	**1.93**	1.86	1.62	1.68	1.56	1.66	1.84	1.67
Operating	**11.42**	**9.68**	13.34	11.30	9.47	10.20	8.78	9.29	9.60
Netback	**76.95**	**86.01**	84.57	60.91	37.05	45.42	41.40	33.94	27.53
Total Liquids *($/bbl)*									
Price	**91.72**	**98.85**	101.46	75.44	50.05	59.60	53.37	46.81	40.25
Production and mineral taxes	**1.88**	**2.09**	2.09	1.46	1.08	1.32	0.81	1.16	1.04
Transportation and selling	**1.62**	**1.72**	1.67	1.46	1.51	1.39	1.47	1.65	1.51
Operating	**10.30**	**8.66**	12.00	10.30	8.57	9.19	7.87	8.41	8.81
Netback	**77.92**	**86.38**	85.70	62.22	38.89	47.70	43.22	35.59	28.89
Total *($/Mcfe)*									
Price	**9.90**	**10.04**	11.02	8.61	6.35	6.57	5.80	6.65	6.40
Production and mineral taxes	**0.32**	**0.32**	0.37	0.28	0.18	0.15	0.19	0.15	0.24
Transportation and selling	**0.51**	**0.53**	0.50	0.50	0.42	0.42	0.41	0.43	0.42
Operating [(2)]	**1.02**	**0.75**	1.17	1.15	0.93	1.02	0.83	0.93	0.95
Netback	**8.05**	**8.44**	8.98	6.68	4.82	4.98	4.37	5.14	4.79

(1) Q1 2007 includes a prior year under accrual of operating costs of approximately $1.82/bbl.
(2) Year-to-date operating costs include costs related to long-term incentives of $0.02/Mcfe (2007 - $0.04/Mcfe).

Impact of Realized Financial Hedging

Natural Gas *($/Mcf)*	**(0.61)**	**(0.80)**	(1.29)	0.27	1.33	1.49	1.65	1.24	0.92
Liquids *($/bbl)*	**(8.23)**	**(7.97)**	(10.99)	(5.85)	(3.05)	(8.76)	(4.36)	(1.34)	2.34
Total *($/Mcfe)*	**(0.74)**	**(0.89)**	(1.38)	0.05	0.99	0.96	1.21	0.96	0.82

EnCana Corporation

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