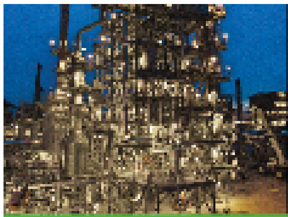

second quarter | 2008

ENCANA.
energy for people

EnCana generates second quarter cash flow of US$2.9 billion, or $3.85 per share – up 16 percent

Second quarter natural gas production up 10 percent to 3.8 billion cubic feet per day

Strong outlook for gas production growth and prices triggers increase to EnCana's 2008 forecast for cash flow and gas production

Calgary, Alberta, (July 24, 2008) – EnCana Corporation (TSX & NYSE: ECA) achieved strong increases in cash flow and operating earnings in the second quarter of 2008 as a result of solid performance from the company's North American portfolio of resource plays and substantial increases in commodity prices.

"Once again our strong operating results demonstrate the substantial value-creation capacity of our resource play strategy. Second quarter cash flow per share and operating earnings per share increased 16 and 9 percent respectively over last year while natural gas production is ahead of expectations. Led by the East Texas, Jonah, Bighorn and Alberta coalbed methane (CBM) resource plays, our low-risk portfolio of unconventional resources continues to deliver sustainable growth across North America. In the second quarter, the upstream business of our Integrated Oil division, in particular, benefited from significantly higher field prices," said Randy Eresman, EnCana's President & Chief Executive Officer.

EnCana expanding investments in North American resource portfolio

"With natural gas production growing faster than forecast and stronger than expected prices, we are raising our 2008 cash flow forecast to a range of $10 billion to $11 billion from a current level of $9.6 billion to $10 billion. Our full-year gas production forecast is also increasing to an expected average of 3.85 Bcf/d. We are directing the higher than originally forecast cash flows into growing our already strong position in the Haynesville Shale in Louisiana, where recent test wells are demonstrating very strong potential. At the same time, we are stepping up our divestiture program for the remainder of the year to offset the additional costs of expanding shale gas lands and resources," Eresman said.

Shale plays continue to show promise

"In the second quarter we announced an expansion of our sizeable position in British Columbia's Horn River and Louisiana's Haynesville natural gas shale plays. At Horn River, two of our recently completed wells are producing at a very strong first-month average rate in excess of 5 million cubic feet per day (MMcf/d). At Haynesville, during a two-day test, the initial flow rate of a second horizontal well was 15 MMcf/d. These well results are exceptional and are a strong indication that the addition of these plays has the potential to accelerate the pace of our natural gas growth," Eresman said.

Integrated Oil production growth set to ramp up

"At Foster Creek, first production from our newest expansion phase, which will add 30,000 bbls/d of gross production capacity, is expected to start ramping up in the fourth quarter 2008. The next 30,000 bbls/d phase is expected to be completed in the first quarter of 2009. Combined, these two phases are scheduled to double our gross production capacity at Foster Creek to 120,000 bbls/d. Production is forecast to begin ramping up later this year and continue through 2009. At Christina Lake, we are steaming wells in our recently completed expansion, which is expected to increase our gross production capacity to 18,000 bbls/d by the end of the year, with production ramping up through 2009," Eresman said.

"Plans for splitting EnCana into two strong independent companies focused on distinct businesses – unconventional natural gas (GasCo) and integrated oil (IOCo) – are proceeding well and we are working towards completing the transaction early in 2009," Eresman said.

Second Quarter 2008 Highlights

(all year-over-year comparisons are to the second quarter of 2007)

Financial

- Cash flow increased 16 percent per share to $3.85, or $2.9 billion
- Operating earnings were up 9 percent per share to $1.96, or $1.5 billion
- Net earnings were down 14 percent per share to $1.63, or $1.2 billion, primarily due to unrealized mark-to-market losses on risk management activities of $235 million after-tax compared to gains of $47 million after-tax in 2007
- Operating cash flow generated from the Integrated Oil division totalled $527 million, comprised of $185 million from the upstream operations, a 59 percent increase due to strong field prices, and $342 million from the downstream business, a decrease of 22 percent due to weaker refining margins
- Capital investment was in line with guidance at $1.7 billion, up about 47 percent in large part due to continued development of East Texas and other key resource plays, as well as the expansion of the company's upstream and downstream integrated oil capacity
- Free cash flow decreased $206 million to $1.2 billion (free cash flow is defined in Note 1 on page 8)
- Realized natural gas prices were up 12 percent to $8.54 per thousand cubic feet (Mcf) and realized liquids prices increased 99 percent to $90.47 per barrel (bbl). These prices include the impact of financial hedges
- EnCana purchased approximately 200,000 common shares at an average share price of $74.81 under the Normal Course Issuer Bid, for a total cost of $15 million.

Operating – Upstream

- Key resource play production was up 14 percent, with a 17 percent increase in natural gas production and oil production down 9 percent
- Total natural gas production increased 10 percent to 3.8 billion cubic feet per day (Bcf/d), up 11 percent per share
- Total oil and natural gas liquids (NGLs) production decreased 4 percent to approximately 128,000 barrels per day (bbls/d), down 3 percent per share
- Oil production at Foster Creek and Christina Lake was down 12 percent to approximately 24,700 bbls/d (net to EnCana) due to an extended turnaround in the second quarter at Foster Creek. Current net production is about 30,000 bbls/d
- Operating and administrative costs of $1.71 per thousand cubic feet equivalent (Mcfe) increased 46 percent from $1.17 per Mcfe one year earlier. More than half of the increase was due to long-term incentive costs and an appreciation of the Canadian dollar compared to the U.S. dollar. When those items are factored out, operating and administrative costs were in line with guidance of $1.40 per Mcfe. The rest of the increase was due to reorganization costs, increased activity levels and other administrative costs.

Operating – Downstream

- Refined products averaged 464,000 bbls/d (232,000 bbls/d net to EnCana), up 10 percent
- Refinery crude utilization of 97 percent or 437,000 bbls/d crude throughput (218,500 bbls/d net to EnCana), up 10 percent, from the second quarter of 2007, due to a major turnaround and new coker startup at the Borger refinery in June, 2007.

Guidance for total cash flow increases to a range of $10 billion to $11 billion

Based on the company's strong cash flow performance to date and natural gas production and commodity price expectations for the remainder of the year, EnCana is increasing its 2008 guidance for total cash flow to a range of $10 billion to $11 billion, or between $13.30 and $14.65 per share. EnCana is also increasing its natural gas production forecast by 70 MMcf/d to 3.85 Bcf/d, or 8 percent higher than 2007 gas production. Key gas resource play production in 2008 is now expected to average 3.14 Bcf/d, up 60 MMcf/d. Production from the company's Foster Creek and Christina Lake projects is now expected to average about 31,000 bbls/d, down about 3,000 bbls/d due to an unexpected power outage and an extended plant turnaround in the second quarter at Foster Creek. As well, the company is planning a more ambitious divestiture program. Proceeds from planned asset sales are expected to offset additional land purchases in 2008, resulting in net proceeds from acquisitions and divestitures of $500 million, which is in line with guidance. Updated guidance is posted on the company's website www.encana.com.

Managing costs through long-term drilling contracts

"As a result of higher commodity prices and increased activity, we are seeing signs of cost inflation in services and materials – particularly for steel and fuels, and we believe inflationary pressure may continue to climb the rest of the year. EnCana has largely managed to offset inflationary pressures to date through a series of long-term contracts. For example, we have been working to lock in longer-term contracts for our well fracturing services. The majority of these contracts are priced at current levels. Significant portions of our steel requirements were contracted early so that we have the benefit of those more favourable cost levels. Going forward, we will continue to pursue cost management opportunities when possible," Eresman said.

Key resource play natural gas production up 17 percent in second quarter

Total natural gas production increased 10 percent in the second quarter to 3.8 Bcf/d, driven by a 17 percent increase in EnCana's natural gas key resource plays to 3.15 Bcf/d. In the U.S. increases were led by East Texas at 127 percent as a result of drilling success as well as incremental volumes from the Deep Bossier acquisition. In the Canadian Foothills natural gas production was up 5 percent, with drilling success and new facilities in the key resource plays of Bighorn in west central Alberta, CBM in central Alberta and Cutbank Ridge straddling the British Columbia-Alberta boundary.

Integrated Oil benefits from higher oil prices

Integrated Oil generated $527 million in operating cash flow, down slightly from $557 million in the same quarter of 2007. The upstream business benefited from a 138 percent increase in the average heavy oil price to $93.64 per bbl at Foster Creek and Christina Lake. Operating cash flow from the downstream business was impacted by significantly weaker refining margins. Operating cash flow for the second quarter includes $172 million related to lower purchased product costs as a result of accounting for inventory based on a first-in first-out valuation which is required under Canadian generally accepted accounting principles. This inventory valuation methodology results in lower product charges to operations in a rising input cost environment. The Chicago 3-2-1 crack spread averaged $13.60 per bbl in the quarter, down 55 percent from $30.12 per bbl from the same period last year when crack spreads reached record levels as gasoline inventories were drawn down to five-year lows. The weaker refining margins were offset by the higher upstream pricing, which demonstrates the benefit of the company's integration strategy. Second quarter oil production at Foster Creek and Christina Lake was down 12 percent to about 24,700 bbls/d (net to EnCana), primarily due to an extended scheduled turnaround at Foster Creek. Current net production is approximately 30,000 bbls/d.

<u>IMPORTANT NOTE</u>: 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 six months ended June 30) ($ millions, except per share amounts)	**Q2 2008**	Q2 2007	% Δ	**6 months 2008**	6 months 2007	% Δ
Cash flow[1]	**2,889**	2,549	+13	**5,278**	4,301	+23
Per share diluted	**3.85**	3.33	+16	**7.02**	5.56	+26
Operating earnings[1]	**1,469**	1,369	+7	**2,514**	2,219	+13
Per share diluted	**1.96**	1.79	+9	**3.34**	2.87	+16
Net earnings	**1,221**	1,446	-16	**1,314**	1,943	-32
Per share diluted	**1.63**	1.89	-14	**1.75**	2.51	-30
Earnings Reconciliation Summary – Total Consolidated						
Net earnings (loss)	**1,221**	1,446		**1,314**	1,943	
(Add back losses & deduct gains)						
Unrealized mark-to-market hedging gain (loss), after-tax	**(235)**	47		**(972)**	(376)	
Non-operating foreign exchange gain (loss), after-tax	**(13)**	(7)		**(228)**	4	
Gain (loss) on discontinuance, after-tax	**-**	-		**-**	59	
Future tax recovery due to tax rate reductions	**-**	37		**-**	37	
Operating earnings[1]	**1,469**	1,369	+7	**2,514**	2,219	+13
Per share diluted	**1.96**	1.79	+9	**3.34**	2.87	+16

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 six months ended June 30) (After royalties)	**Q2 2008**	Q2 2007	% Δ	**6 months 2008**	6 months 2007	% Δ
Natural Gas (MMcf/d)	**3,841**	3,506	+10	**3,787**	3,454	+10
Natural gas production per 1,000 shares (Mcf)	**466**	421	+11	**919**	819	+12
Oil and NGLs (Mbbls/d)	**128**	133	-4	**132**	132	-
Oil and NGLs production per 1,000 shares (Mcfe)	**93**	96	-3	**193**	188	+3
Total Production (MMcfe/d)	**4,607**	4,306	+7	**4,582**	4,246	+8
Total per 1,000 shares (Mcfe)	**559**	517	+8	**1,112**	1,007	+10
Net wells drilled	**409**	569	-28	**1,552**	1,833	-15

Growth from key North American resource plays

Resource Play (After royalties)	Daily Production								
	2008			2007					2006
	YTD	**Q2**	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas (MMcf/d)									
Jonah	**613**	**630**	595	557	612	588	523	504	464
Piceance	**377**	**383**	372	348	351	354	349	334	326
East Texas	**294**	**316**	273	143	187	144	139	103	99
Fort Worth	**138**	**137**	140	124	138	128	124	106	101
Greater Sierra	**211**	**219**	205	211	221	220	219	186	213
Cutbank Ridge[1]	**275**	**280**	271	258	283	269	248	232	189
Bighorn[1]	**158**	**170**	146	126	136	136	122	109	97
CBM	**300**	**303**	298	259	283	256	245	251	194
Shallow Gas	**713**	**712**	715	726	727	713	729	735	739
Total natural gas[1] (MMcf/d)	**3,079**	**3,150**	3,015	2,752	2,938	2,808	2,698	2,560	2,422
Oil (Mbbls/d)									
Foster Creek	**24**	**21**	27	24	25	26	25	20	18
Christina Lake	**3**	**4**	2	3	2	3	3	3	3
Pelican Lake	**23**	**21**	24	23	24	24	23	23	24
Weyburn[2]	**14**	**13**	14	15	14	15	14	15	15
Total oil (Mbbls/d)[2]	**64**	**59**	67	65	65	68	65	61	60
Total (MMcfe/d)[1,2]	**3,464**	**3,506**	3,417	3,142	3,328	3,210	3,088	2,926	2,782
% change from prior period		**+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 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 an oil key resource play.

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled								
	2008			2007					2006
	YTD	**Q2**	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas									
Jonah	**92**	**49**	43	135	23	31	42	39	163
Piceance	**164**	**81**	83	286	77	72	72	65	220
East Texas	**33**	**22**	11	35	8	9	11	7	59
Fort Worth	**41**	**20**	21	75	15	17	29	14	97
Greater Sierra	**63**	**27**	36	109	27	27	32	23	115
Cutbank Ridge[1]	**48**	**24**	24	93	11	23	26	33	134
Bighorn[1]	**48**	**18**	30	62	6	18	10	28	58
CBM	**261**	**10**	251	1,079	330	323	18	408	729
Shallow Gas	**579**	**83**	496	1,914	649	608	241	416	1,310
Total gas wells[1]	**1,329**	**334**	995	3,788	1,146	1,128	481	1,033	2,885
Oil									
Foster Creek	**13**	**1**	12	23	6	8	1	8	3
Christina Lake	**-**	**-**	-	3	-	1	2	-	1
Pelican Lake	**-**	**-**	-	-	-	-	-	-	-
Weyburn[2]	**14**	**5**	9	37	10	9	9	9	35
Total oil wells[2]	**27**	**6**	21	63	16	18	12	17	39
Total[1,2]	**1,356**	**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 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 an oil key resource play.

Natural gas shale resource play update
EnCana announced on June 16, 2008 that it has established a leading land and resource position in the Horn River Shale in northeast British Columbia and the Haynesville Shale in Louisiana and Texas. EnCana has drilled several exploration wells that have shown strong potential to deliver commercial volumes of natural gas. At Horn River, two of EnCana's recently completed wells are producing at a very strong first-month average rate in excess of 5 MMcf/d. In the Haynesville Shale play, EnCana has early results from its second horizontal well, which flowed at an initial two-day rate of 15 MMcf/d. In the second quarter EnCana increased its leased acreage in the Haynesville Shale play to 370,000 net acres through a series of transactions. The company also reached an agreement in July, 2008 to acquire an additional 89,000 acres of mineral rights from Indigo Minerals LLC for $457 million.

Second quarter 2008 natural gas and oil prices

	Q2 2008	Q2 2007	% Δ	**6 months 2008**	6 months 2007	% Δ
Natural gas ($/Mcf)						
NYMEX	**10.93**	7.55	+45	**9.48**	7.16	+32
EnCana realized gas price[1]	**8.54**	7.62	+12	**8.29**	7.43	+12
Oil and NGLs ($/bbl)						
WTI	**123.80**	65.02	+90	**111.12**	61.68	+80
Western Canadian Select (WCS)	**102.18**	45.84	+123	**89.58**	43.85	+104
Differential WTI/WCS	**21.62**	19.18	+13	**21.54**	17.83	+21
EnCana realized liquids price [1]	**90.47**	45.47	+99	**79.77**	44.02	+81
Chicago 3-2-1 crack spread ($bbl)	**13.60**	30.12	-55	**10.65**	21.51	-50

1 Realized prices include the impact of financial hedging.

Price risk management

Risk management positions at June 30, 2008 are presented in Note 17 to the unaudited Interim Consolidated Financial Statements. In the second quarter of 2008, EnCana's commodity price risk management measures resulted in realized losses of approximately $400 million after-tax, composed of a $308 million after-tax loss on gas hedges, and a $92 million after-tax loss on oil and other hedges. The realized losses in the second quarter reflect the dramatic increase in oil prices in the past year and natural gas prices over the past few months compared to the portion of EnCana's sales that are hedged at fixed prices – a risk management strategy that is aimed at providing more certainty of cash flow to fund the company's annual capital investment program. EnCana has hedged about 1.5 Bcf/d of expected 2008 gas production for the balance of the year at an average NYMEX equivalent price of $8.20 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 2009, EnCana has 391 MMcf/d of its expected natural gas production under fixed price contracts at an average NYMEX equivalent price of $9.85 per Mcf and 341 MMcf/d under NYMEX put options at an average strike of $8.85 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 in 2008 using a combination of downstream transportation and basis hedges, including some hedges that are based on a percentage of NYMEX prices. At June 30, 2008, U.S. basis hedges, a combination of Rockies, Mid-Continent and San Juan instruments, had an effective average differential to NYMEX of $1.66 per Mcf for the rest of 2008. EnCana has also hedged about 8 percent of its expected 2008 Canadian gas production at an average AECO basis differential of 76 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 September 30, 2008 to common shareholders of record as of September 15, 2008. Based on the July 23, 2008 closing share price on the New York Stock Exchange of $72.62, this represents an annualized yield of about 2.2 percent.

Corporate reorganization to create two energy companies focused on unconventional resources

On May 11, 2008, EnCana announced plans to split into two highly focused 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 natural gas and crude oil resource plays. The proposed corporate reorganization, expected to close in early 2009, would be implemented through a Plan of Arrangement and is subject to shareholder and court approval. An information circular setting out the details of the Plan of Arrangement is expected to be mailed to EnCana shareholders in November, followed by a shareholders meeting planned for mid December. The working names of the two companies are GasCo and IOCo. GasCo will retain the name of EnCana Corporation while the permanent name of IOCo will be determined prior to the close of the transaction. For further information on the announcement see the company's website www.encana.com.

Normal Course Issuer Bid

In the second quarter of 2008, EnCana purchased for cancellation approximately 200,000 common shares at an average price of $74.81 per share under the company's Normal Course Issuer Bid for a total cost of $15 million. As a result of the proposed corporate reorganization, the company has suspended further purchases for 2008.

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 June 30, 2008, EnCana's net debt-to-capitalization ratio was 36 percent, including mark-to-market losses on risk management instruments, which increased net debt. Excluding this mark-to-market impact, the net debt-to-capitalization ratio would have been 34 percent. EnCana's net debt-to-adjusted-EBITDA multiple, on a trailing 12-month basis, was 1.3 times at the end of the second quarter. The company expects to be in the lower end of its managed ranges by year-end.

In the quarter, EnCana invested $1.7 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 joint venture with ConocoPhillips.

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 $65 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, free cash flow, and cash flow per share); the anticipated ability to meet the company's guidance forecasts; 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 mailing an information circular to shareholders, holding a shareholders meeting and the potential closing date; projections of crude oil and natural gas prices, including basis differentials for various regions; anticipated expansion and production at Foster Creek and Christina Lake; 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: 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; 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, and for GasCo and IOCo pro-forma the proposed reorganization transaction, is based upon achieving average production of oil and gas for 2008 as set out above, average commodity prices for 2008 based on actual results for the second quarter of 2008, and for the balance of 2008, a WTI price of $130/bbl for oil, a NYMEX price of $11.00/Mcf for natural gas, an average U.S./Canadian dollar foreign exchange rate of $0.98, an average Chicago crack spread for 2008 of $10.00/bbl for refining margins, and an average number of outstanding shares for EnCana of approximately 750 million. 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 June 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 July 23, 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 June 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 highly focused energy companies - one a North American natural gas company and the other a fully integrated oil company with in-situ oilsands properties and refineries supplemented by reliable production from various natural gas and crude oil resource plays. The proposed corporate reorganization, expected to close in early 2009, would 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 every EnCana shareholder receiving one share of each entity in exchange for each EnCana Common share held. The working names of the two companies are GasCo and IntegratedOilco ("IOCo") respectively. GasCo will retain the name of EnCana Corporation while the permanent name of IOCo will be determined prior to the close of the transaction. Additional detail on the proposed corporate reorganization is available in the news release dated May 11, 2008 on our website at www.encana.com.

As a result of the proposed corporate reorganization, 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.

GasCo's operating segments will include EnCana's Canadian Foothills, United States and Offshore and International segments. IOCo's operating segments will include EnCana's Integrated Oil and Canadian Plains segments.

EnCana has defined its 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. Offshore and International exploration is mainly focused on opportunities in Atlantic Canada, the Middle East 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 focused on enhancing the sale of EnCana's upstream production. As part of these activities, Market Optimization buys and sells third party products to enhance EnCana's operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **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 second quarter of 2008 compared to the second quarter of 2007, EnCana:

- Announced its plans to split into two highly focused publicly traded energy companies;
- Increased Cash Flow by 13 percent to $2,889 million;
- Increased Operating Earnings by 7 percent to $1,469 million;
- Reported a 16 percent decrease in Net Earnings to $1,221 million primarily due to after-tax unrealized mark-to-market hedging losses of $235 million in 2008 compared with gains of $47 million in 2007;
- Reported a $206 million decrease in Free Cash Flow to $1,171 million;
- Grew total production 7 percent to 4,607 million cubic feet equivalent ("MMcfe") per day ("MMcfe/d"), primarily from gas. On a per share basis, production increased 8 percent;
- Increased production from natural gas key resource plays 17 percent and reported lower production from oil key resource plays of 9 percent;
- Reported a 54 percent increase in natural gas prices, excluding financial hedges, to $9.83 per thousand cubic feet ("Mcf") and a 117 percent increase in liquids prices, excluding financial hedges, to $101.46 per barrel ("bbl"). Realized hedging losses were $400 million after-tax in 2008 compared with gains of $246 million after-tax in 2007;
- Purchased approximately 0.2 million of its Common Shares at an average price of $74.81 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of $15 million in the second quarter of 2008; and
- Was impacted by a 9 percent increase in the average U.S./Canadian dollar exchange rate that increased reported capital investment by $57 million, operating expense by $24 million, administrative expense by $6 million and depreciation, depletion and amortization ("DD&A") expense by $51 million.

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

- Announced its plans to split into two highly focused publicly traded energy companies;
- Increased Cash Flow by 23 percent to $5,278 million;
- Increased Operating Earnings by 13 percent to $2,514 million;
- Reported a 32 percent decrease in Net Earnings to $1,314 million primarily due to after-tax unrealized mark-to-market hedging losses of $972 million in 2008 compared with losses of $376 million in 2007;
- Increased Free Cash Flow by $65 million to $1,711 million;
- Grew total production 8 percent to 4,582 MMcfe/d. On a per share basis, production increased 10 percent;
- Increased production from natural gas key resource plays 17 percent and from oil key resource plays 1 percent;
- Reported a 39 percent increase in natural gas prices, excluding financial hedges, to $8.81 per Mcf and a 103 percent increase in liquids prices, excluding financial hedges, to $88.13 per bbl. Realized hedging losses were $387 million after-tax in 2008 compared with gains of $454 million after-tax in 2007;
- Purchased approximately 4.8 million of its Common Shares at an average price of $67.13 per share under the NCIB for a total cost of $326 million in the six months of 2008;
- Was impacted by a 13 percent increase in the average U.S./Canadian dollar exchange rate that increased reported capital investment by $220 million, operating expense by $72 million, administrative expense by $20 million and DD&A expense by $141 million; and
- Increased its quarterly dividends to 40 cents per share during the six months of 2008 compared to 20 cents per share for the same period in 2007.

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 June 30 2008	2008 vs 2007	2007	Six Months Ended June 30 2008	2008 vs 2007	2007
Natural Gas Price Benchmarks						
AECO *(C$/Mcf)*	**$ 9.35**	**27%**	$ 7.37	**$ 8.24**	**11%**	$ 7.41
NYMEX *($/MMBtu)*	**10.93**	**45%**	7.55	**9.48**	**32%**	7.16
Rockies (Opal) *($/MMBtu)*	**8.56**	**122%**	3.85	**7.79**	**66%**	4.70
Texas (HSC) *($/MMBtu)*	**10.58**	**46%**	7.26	**9.16**	**33%**	6.90
Basis Differential *($/MMBtu)*						
AECO/NYMEX	**1.71**	**90%**	0.90	**1.28**	**97%**	0.65
Rockies/NYMEX	**2.37**	**-36%**	3.70	**1.69**	**-31%**	2.46
Texas/NYMEX	**0.35**	**21%**	0.29	**0.32**	**23%**	0.26
Crude Oil Price Benchmarks						
West Texas Intermediate (WTI) *($/bbl)*	**123.80**	**90%**	65.02	**111.12**	**80%**	61.68
Western Canadian Select (WCS) *($/bbl)*	**102.18**	**123%**	45.84	**89.58**	**104%**	43.85
Differential - WTI/WCS *($/bbl)*	**21.62**	**13%**	19.18	**21.54**	**21%**	17.83
Refining Margin Benchmark						
Chicago 3-2-1 Crack Spread *($/bbl)* (1)	**13.60**	**-55%**	30.12	**10.65**	**-50%**	21.51
Foreign Exchange						
U.S./Canadian Dollar Exchange Rate	**0.990**	**9%**	0.911	**0.993**	**13%**	0.881

(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)	Six Months Ended June 30 2008	Six Months Ended June 30 2007	2008 Q2	2008 Q1	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Q4	2006 Q3
Total Consolidated										
Cash Flow (1)	**$ 5,278**	$ 4,301	**$ 2,889**	$ 2,389	$ 1,934	$ 2,218	$ 2,549	$ 1,752	$ 1,761	$ 1,894
- per share – diluted	**7.02**	5.56	**3.85**	3.17	2.56	2.93	3.33	2.25	2.18	2.30
Net Earnings	**1,314**	1,943	**1,221**	93	1,082	934	1,446	497	663	1,358
- per share – basic	**1.75**	2.54	**1.63**	0.12	1.44	1.24	1.91	0.65	0.84	1.68
- per share – diluted	**1.75**	2.51	**1.63**	0.12	1.43	1.24	1.89	0.64	0.82	1.65
Operating Earnings (2)	**2,514**	2,219	**1,469**	1,045	849	1,032	1,369	850	675	1,078
- per share – diluted	**3.34**	2.87	**1.96**	1.39	1.12	1.37	1.79	1.09	0.84	1.31
Continuing Operations										
Cash Flow from Continuing Operations (1)	**5,278**	4,301	**2,889**	2,389	1,934	2,218	2,549	1,752	1,742	1,883
Net Earnings from Continuing Operations	**1,314**	1,943	**1,221**	93	1,007	934	1,446	497	643	1,343
- per share – basic	**1.75**	2.54	**1.63**	0.12	1.34	1.24	1.91	0.65	0.81	1.66
- per share – diluted	**1.75**	2.51	**1.63**	0.12	1.33	1.24	1.89	0.64	0.80	1.63
Operating Earnings from Continuing Operations (2)	**2,514**	2,219	**1,469**	1,045	849	1,032	1,369	850	672	1,064
Revenues, Net of Royalties	**12,663**	10,049	**7,321**	5,342	5,801	5,596	5,613	4,436	3,676	4,029

(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 June 30		Six Months Ended June 30	
($ millions)	**2008**	2007	**2008**	2007
Cash From Operating Activities	**$ 1,996**	$ 2,148	**$ 3,754**	$ 4,056
(Add back) deduct:				
Net change in other assets and liabilities	**(171)**	(16)	**(264)**	4
Net change in non-cash working capital	**(722)**	(385)	**(1,260)**	(249)
Cash Flow	**$ 2,889**	$ 2,549	**$ 5,278**	$ 4,301

Three Months Ended June 30, 2008 versus 2007

Cash Flow in the second quarter of 2008 increased $340 million or 13 percent compared to the second quarter of 2007 as a result of:

- Average total liquids prices, excluding financial hedges, increased 117 percent to $101.46 per bbl in 2008 compared to $46.81 per bbl in 2007;
- Average total natural gas prices, excluding financial hedges, increased 54 percent to $9.83 per Mcf in 2008 compared to $6.38 per Mcf in 2007; and
- Natural gas production volumes in 2008 increased 10 percent to 3,841 million cubic feet ("MMcf") of gas per day ("MMcf/d") from 3,506 MMcf/d in 2007.

Cash Flow was reduced by:

- Realized financial natural gas, crude oil and other commodity hedging losses of $400 million after-tax in 2008 compared with gains of $246 million after-tax in 2007;
- Increases in operating, production and mineral taxes, transportation and selling, administrative and interest expenses in 2008 compared with 2007;
- Current tax recovery in 2007 of $174 million related to legislative changes with no comparable amount in 2008; and
- Operating cash flows from downstream operations decreased $99 million.

Six Months Ended June 30, 2008 versus 2007

Cash Flow in the six months of 2008 increased $977 million or 23 percent compared to the six months of 2007 as a result of:

- Average total liquids prices, excluding financial hedges, increased 103 percent to $88.13 per bbl in 2008 compared to $43.50 per bbl in 2007;
- Natural gas production volumes in 2008 increased 10 percent to 3,787 MMcf/d from 3,454 MMcf/d in 2007; and
- Average total natural gas prices, excluding financial hedges, increased 39 percent to $8.81 per Mcf in 2008 compared to $6.35 per Mcf in 2007.

Cash Flow was reduced by:

- Realized financial natural gas, crude oil and other commodity hedging losses of $387 million after-tax in 2008 compared with gains of $454 million after-tax in 2007;
- Increases in operating, production and mineral taxes, transportation and selling, administrative and interest expenses in 2008 compared with 2007;
- Current tax recovery in 2007 of $174 million related to legislative changes with no comparable amount in 2008; and
- Operating cash flows from downstream operations decreased $115 million.

NET EARNINGS

Three Months Ended June 30, 2008 versus 2007

EnCana's second quarter 2008 Net Earnings were $225 million lower 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 losses of $235 million after-tax in 2008 compared with gains of $47 million after-tax in 2007;
- DD&A increased $198 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 losses, future income taxes increased in 2008 compared to 2007 primarily due to a one time tax recovery of $57 million in 2007 for a tax legislative change with no comparable amount in 2008 and future income taxes on unrealized foreign exchange gains in 2008 of $21 million with no comparable amount in 2007.

Six Months Ended June 30, 2008 versus 2007

EnCana's six months of 2008 Net Earnings were $629 million lower 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 losses of $972 million after-tax in 2008 compared with losses of $376 million after-tax in 2007;
- DD&A increased $390 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 losses, future income taxes increased in 2008 compared to 2007 primarily due to future income taxes on unrealized foreign exchange gains in 2008 of $173 million with no comparable amount in 2007 and a one time tax recovery of $57 million in 2007 for a tax legislative change 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 six months of 2008 and also in the comparative period in 2007.

Summary of Operating Earnings

	Three Months Ended June 30				Six Months Ended June 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	**$ 1,221**	**$ 1.63**	$ 1,446	$ 1.89	**$ 1,314**	**$ 1.75**	$ 1,943	$ 2.51
Add back (losses) and deduct gains:								
Unrealized mark-to-market accounting gain (loss), after-tax	**(235)**	**(0.31)**	47	0.06	**(972)**	**(1.29)**	(376)	(0.49)
Non-operating foreign exchange gain (loss), after-tax (1)	**(13)**	**(0.02)**	(7)	(0.01)	**(228)**	**(0.30)**	4	0.01
Gain (loss) on discontinuance, after-tax (2)	**-**	**-**	-	-	**-**	**-**	59	0.07
Future tax recovery due to tax rate reductions	**-**	**-**	37	0.05	**-**	**-**	37	0.05
Operating Earnings (3) (4)	**$ 1,469**	**$ 1.96**	$ 1,369	$ 1.79	**$ 2,514**	**$ 3.34**	$ 2,219	$ 2.87

(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 2007, gain on sale of 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 increased 9 percent to $0.990 in the second quarter of 2008 compared to $0.911 in the second quarter of 2007 and increased 13 percent to $0.993 in the six months of 2008 compared to $0.881 in the six 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 June 30, 2008		Six Months Ended June 30, 2008	
Average U.S./Canadian Dollar Exchange Rate	$ 0.990		$ 0.993	
Change from comparative period in 2007	0.079		0.112	
	$ millions	$/Mcfe	$ millions	$/Mcfe
Increase (decrease) in:				
Capital Investment	$ 57		$ 220	
Operating Expense	24	0.06	72	0.09
Administrative Expense	6	0.01	20	0.03
DD&A Expense	51		141	

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

	Six Months Ended June 30		2008		2007				2006	
	2008	2007	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Produced Gas *(MMcf/d)*										
Canadian Plains	857	882	856	860	876	858	874	891	901	899
Canadian Foothills	1,273	1,214	1,289	1,256	1,313	1,280	1,231	1,196	1,207	1,155
United States	1,591	1,263	1,629	1,552	1,464	1,387	1,303	1,222	1,201	1,197
Integrated Oil - Other[(2)]	66	95	67	65	69	105	98	91	97	108
	3,787	3,454	3,841	3,733	3,722	3,630	3,506	3,400	3,406	3,359
Crude Oil *(bbls/d)*										
Canadian Plains	67,439	71,387	65,097	69,781	70,287	70,711	70,148	72,639	69,567	76,280
Canadian Foothills	8,621	8,223	8,376	8,867	8,441	7,978	7,959	8,489	8,643	8,717
Foster Creek/Christina Lake	27,024	25,645	24,671	29,376	27,190	28,740	27,994	23,269	46,678	43,073
Integrated Oil - Other[(2)]	3,261	2,737	3,009	3,514	3,040	2,235	2,489	2,990	5,341	3,953
	106,345	107,992	101,153	111,538	108,958	109,664	108,590	107,387	130,229	132,023
NGLs *(bbls/d)*										
Canadian Plains	1,226	1,204	1,189	1,262	1,422	1,209	1,206	1,203	1,397	1,326
Canadian Foothills	11,517	9,655	11,779	11,256	10,966	9,932	9,811	9,497	10,459	10,061
United States	13,358	13,159	13,482	13,232	14,791	15,578	13,809	12,503	12,584	13,311
	26,101	24,018	26,450	25,750	27,179	26,719	24,826	23,203	24,440	24,698
Total *(MMcfe/d)* [(1)]	4,582	4,246	4,607	4,557	4,539	4,448	4,306	4,184	4,334	4,299

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) Produced gas volumes include Athabasca and crude oil volumes include Senlac.

Production volumes increased 7 percent or 301 MMcfe/d in the second quarter of 2008 compared to the second quarter of 2007 due to increased production from EnCana's natural gas key resource plays of 17 percent offset partially by decreased production from crude oil key resource plays of 9 percent and natural declines in conventional properties.

Production volumes increased 8 percent or 336 MMcfe/d in the six months of 2008 compared to the six months of 2007 due to increased production from EnCana's natural gas key resource plays of 17 percent and from crude oil key resource plays of 1 percent offset partially by natural declines in conventional properties.

Key Resource Plays

	Three Months Ended June 30					Six Months Ended June 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	**630**	**20%**	523	**49**	42	**613**	**19%**	514	**92**	81
Piceance	**383**	**10%**	349	**81**	72	**377**	**10%**	342	**164**	137
East Texas	**316**	**127%**	139	**22**	11	**294**	**143%**	121	**33**	18
Fort Worth	**137**	**10%**	124	**20**	29	**138**	**20%**	115	**41**	43
Greater Sierra	**219**	**0%**	219	**27**	32	**211**	**5%**	202	**63**	55
Cutbank Ridge(1)	**280**	**13%**	248	**24**	26	**275**	**15%**	240	**48**	59
Bighorn(1)	**170**	**39%**	122	**18**	10	**158**	**37%**	116	**48**	38
CBM	**303**	**24%**	245	**10**	18	**300**	**21%**	248	**261**	426
Shallow Gas	**712**	**-2%**	729	**83**	241	**713**	**-3%**	732	**579**	657
	3,150	**17%**	2,698	**334**	481	**3,079**	**17%**	2,628	**1,329**	1,514
Oil *(Mbbls/d)* (2)										
Foster Creek	**21**	**-16%**	25	**1**	1	**24**	**5%**	23	**13**	9
Christina Lake	**4**	**27%**	3	**-**	2	**3**	**16%**	3	**-**	2
	25	**-12%**	28	**1**	3	**27**	**4%**	26	**13**	11
Pelican Lake	**21**	**-5%**	23	**-**	-	**23**	**1%**	23	**-**	-
Weyburn	**13**	**-10%**	14	**5**	9	**14**	**-9%**	15	**14**	18
	59	**-9%**	65	**6**	12	**64**	**1%**	64	**27**	29
Total *(MMcfe/d)* (3)	**3,506**	**14%**	3,088	**340**	493	**3,464**	**15%**	3,007	**1,356**	1,543

(1) Key resource play production and wells drilled information in 2007 for Cutbank Ridge and Bighorn were restated to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.

(2) Percentage changes are calculated using bbls/d.

(3) 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.

GASCO

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. GasCo's operating segments will include the Canadian Foothills and United States Divisions.

CANADIAN FOOTHILLS AND UNITED STATES

Produced Gas

Three Months Ended June 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	**$ 1,167**	**$ 9.94**	**$ 1,472**	**$ 9.93**
Realized Financial Hedging Gain (Loss)	**(167)**		**(164)**	
Expenses				
Production and mineral taxes	**11**	**0.09**	**107**	**0.72**
Transportation and selling	**51**	**0.43**	**120**	**0.81**
Operating	**163**	**1.39**	**106**	**0.71**
Operating Cash Flow / Netback (1)	**$ 775**	**$ 8.03**	**$ 975**	**$ 7.69**
Netback including Realized Financial Hedging		**$ 6.61**		**$ 6.58**
Gas Production Volumes *(MMcf/d)*		**1,289**		**1,629**

2007	Canadian Foothills		United States	
		$/Mcf		$/Mcf
Revenues, Net of Royalties / Price	$ 769	$ 6.86	$ 679	$ 5.73
Realized Financial Hedging Gain (Loss)	47		310	
Expenses				
Production and mineral taxes	12	0.11	20	0.17
Transportation and selling	49	0.43	77	0.65
Operating	114	1.02	85	0.71
Operating Cash Flow / Netback (1)	$ 641	$ 5.30	$ 807	$ 4.20
Netback including Realized Financial Hedging		$ 5.72		$ 6.81
Gas Production Volumes *(MMcf/d)*		1,231		1,303

(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	$ 816	$ 139	$ 45	**$ 1,000**
United States	989	57	262	**1,308**
Total Produced Gas	$ 1,805	$ 196	$ 307	**$ 2,308**

(1) Includes the impact of realized financial hedging.

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

- A 25 percent increase in U.S. natural gas production volumes and a 5 percent increase in Canadian Foothills natural gas production volumes; and
- A 73 percent increase in U.S. natural gas prices and a 45 percent increase in Canadian Foothills natural gas prices, excluding the impact of financial hedging;

offset by:

- Canadian Foothills realized financial hedging losses of $167 million or $1.42 per Mcf in 2008 compared to gains of $47 million or $0.42 per Mcf in 2007 and U.S. realized financial hedging losses of $164 million or $1.11 per Mcf in 2008 compared to gains of $310 million or $2.61 per Mcf in 2007.

Produced gas volumes in the U.S. increased 25 percent 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 5 percent in 2008 compared to 2007. Drilling success and new facilities in the key resource plays of Coalbed Methane ("CBM"), Bighorn and Cutbank Ridge were offset by natural declines for conventional properties and planned outages due to turnarounds at the Hythe, Sexsmith and McMahon plants.

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. Variability in realized prices also reflects the weighting of EnCana's various gas stream volumes at their respective benchmark price, net of applicable basis differential.

Natural gas per unit production and mineral taxes in the U.S. increased 324 percent or $0.55 per Mcf in 2008 compared to 2007 as a result of higher natural gas prices and Colorado severance tax refunds received in the second quarter of 2007.

Natural gas per unit transportation and selling costs for the U.S. increased 25 percent or $0.16 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 for the Canadian Foothills in 2008 were 36 percent or $0.37 per Mcf higher than in 2007 primarily as a result of higher long-term compensation costs due to the increase in the EnCana share price, higher repairs and maintenance due to planned plant turnarounds in the second quarter of 2008, the higher U.S./Canadian dollar exchange rate, increased gathering and processing and salaries and benefits expenses. Natural gas per unit operating expenses in the U.S. were impacted by higher long-term compensation costs offset by increased production volumes combined with a high proportion of fixed costs.

Six Months Ended June 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	**$**	**2,037**	**$**	**8.79**	**$**	**2,630**	**$**	**9.08**
Realized Financial Hedging Gain (Loss)		**(128)**				**(139)**		
Expenses								
Production and mineral taxes		**14**		**0.06**		**194**		**0.67**
Transportation and selling		**104**		**0.45**		**235**		**0.81**
Operating		**324**		**1.40**		**207**		**0.71**
Operating Cash Flow / Netback (1)	**$**	**1,467**	**$**	**6.88**	**$**	**1,855**	**$**	**6.89**
Netback including Realized Financial Hedging			**$**	**6.33**			**$**	**6.41**
Gas Production Volumes *(MMcf/d)*				**1,273**				**1,591**

2007

	Canadian Foothills				United States			
				$/Mcf				$/Mcf
Revenues, Net of Royalties / Price	$	1,464	$	6.67	$	1,366	$	5.97
Realized Financial Hedging Gain (Loss)		123				454		
Expenses								
Production and mineral taxes		23		0.10		78		0.34
Transportation and selling		94		0.43		143		0.63
Operating		231		1.05		160		0.69
Operating Cash Flow / Netback (1)	$	1,239	$	5.09	$	1,439	$	4.31
Netback including Realized Financial Hedging			$	5.65			$	6.30
Gas Production Volumes *(MMcf/d)*				1,214				1,263

(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	$	1,587	$	224	$	98	**$ 1,909**
United States		1,820		147		524	**2,491**
Total Produced Gas	$	3,407	$	371	$	622	**$ 4,400**

(1) Includes the impact of realized financial hedging.

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

- A 26 percent increase in U.S. natural gas production volumes and a 5 percent increase in Canadian Foothills natural gas production volumes; and
- A 52 percent increase in U.S. natural gas prices and a 32 percent increase in Canadian Foothills natural gas prices, excluding the impact of financial hedging;

offset by:

- Canadian Foothills realized financial hedging losses of $128 million or $0.55 per Mcf in 2008 compared to gains of $123 million or $0.56 per Mcf in 2007 and U.S. realized financial hedging losses of $139 million or $0.48 per Mcf in 2008 compared to gains of $454 million or $1.99 per Mcf in 2007.

Produced gas volumes in the U.S. increased 26 percent 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 5 percent in 2008 compared to 2007. Drilling success and new facilities in the key resource plays of CBM, Bighorn and Cutbank Ridge were offset 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. Variability in realized prices also reflects the weighting of EnCana's various gas stream volumes at their respective benchmark price, net of applicable basis differential.

Natural gas per unit production and mineral taxes in the U.S. increased 97 percent or $0.33 per Mcf in 2008 compared to 2007 as a result of higher natural gas prices and Colorado severance tax refunds received in the second quarter of 2007.

Natural gas per unit transportation and selling costs for the U.S. increased 29 percent or $0.18 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 for the Canadian Foothills in 2008 were 33 percent or $0.35 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 workovers, gathering and processing and salaries and benefits expenses. Natural gas per unit operating expenses in the U.S. were impacted by higher long-term compensation costs offset by increased production volumes combined with a high proportion of fixed costs.

Crude Oil and NGLs

Three Months Ended June 30, 2008 versus 2007

Financial Results

($ millions)	**2008**		2007	
	Canadian Foothills	**United States**	Canadian Foothills	United States
Revenues, Net of Royalties	**$ 174**	**$ 130**	$ 88	$ 70
Expenses				
Production and mineral taxes	**1**	**11**	1	6
Transportation and selling	**3**	**-**	2	-
Operating	**12**	**-**	7	-
Operating Cash Flow	**$ 158**	**$ 119**	$ 78	$ 64

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	$ 88	$ 66	$ 20	**$ 174**
United States	70	63	(3)	**130**
Total Crude Oil and NGLs	$ 158	$ 129	$ 17	**$ 304**

(1) Includes the impact of realized financial hedging.

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

- A 100 percent increase in Canadian Foothills crude oil prices and 87 percent increase in North American NGLs prices, excluding financial hedges;

offset by:

- Canadian Foothills realized financial hedging losses on liquids of $21 million or $11.19 per bbl in 2008 compared to losses of $3 million or $1.64 per bbl in 2007.

Canadian Foothills crude oil production increased 5 percent primarily due to new wells on production in the Bighorn and Clearwater areas.

Per Unit Results – Crude Oil

($ per barrel)	Canadian Foothills	
	2008	2007
Price (1)	**$ 114.28**	$ 57.00
Expenses		
Production and mineral taxes	**2.05**	1.47
Transportation and selling	**2.70**	1.79
Operating	**15.39**	9.31
Netback	**$ 94.14**	$ 44.43
Crude Oil Production Volumes *(bbls/d)*	**8,376**	7,959

(1) Excludes the impact of realized financial hedging.

Canadian Foothills crude oil prices in 2008 increased 100 percent compared to 2007. The increase reflects 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 $8 million or $11.06 per bbl in 2008 compared to losses of approximately $1 million or $1.67 per bbl in 2007.

Canadian Foothills crude oil per unit production and mineral taxes increased 39 percent or $0.58 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 51 percent or $0.91 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 65 percent or $6.08 per bbl compared to 2007 mainly due to increased workovers, gathering and processing, electricity and the higher U.S./Canadian dollar exchange rate.

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 13,482 bbls/d in 2008 compared to 13,809 bbls/d in 2007 and from Canadian Foothills were 11,779 bbls/d in 2008 compared to 9,811 bbls/d in 2007. Average U.S. NGLs realized prices increased 91 percent to $105.73 per bbl in 2008 from $55.43 per bbl in 2007 and average Canadian Foothills NGLs realized prices increased 84 percent to $101.23 per bbl in 2008 from $55.10 per bbl in 2007, which are consistent with the higher WTI benchmark price.

Six Months Ended June 30, 2008 versus 2007

Financial Results

($ millions)	2008		2007	
	Canadian Foothills	**United States**	Canadian Foothills	United States
Revenues, Net of Royalties	**$ 322**	**$ 229**	$ 168	$ 124
Expenses				
Production and mineral taxes	**2**	**20**	1	12
Transportation and selling	**6**	**-**	4	-
Operating	**23**	**-**	14	-
Operating Cash Flow	**$ 291**	**$ 209**	$ 149	$ 112

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	$ 168	$ 116	$ 38	**$ 322**
United States	124	100	5	**229**
Total Crude Oil and NGLs	$ 292	$ 216	$ 43	**$ 551**

(1) Includes the impact of realized financial hedging.

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

- A 90 percent increase in Canadian Foothills crude oil prices and 83 percent increase in North American NGLs prices, excluding financial hedges;

offset by:

- Canadian Foothills realized financial hedging losses on liquids of $31 million or $8.45 per bbl in 2008 compared to gains of $1 million or $0.39 per bbl in 2007.

Canadian Foothills crude oil production increased 5 percent primarily due to new wells on production in the Clearwater area.

Per Unit Results – Crude Oil

($ per barrel)	Canadian Foothills **2008**	2007
Price (1)	**$ 103.53**	$ 54.62
Expenses		
Production and mineral taxes	**1.59**	0.91
Transportation and selling	**2.30**	1.64
Operating	**14.59**	9.67
Netback	**$ 85.05**	$ 42.40
Crude Oil Production Volumes *(bbls/d)*	**8,621**	8,223

(1) Excludes the impact of realized financial hedging.

Canadian Foothills crude oil prices in 2008 increased 90 percent compared to 2007. The increase reflects 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 $13 million or $8.17 per bbl in 2008 compared to gains of approximately $1 million or $0.37 per bbl in 2007.

Canadian Foothills crude oil per unit production and mineral taxes increased 75 percent or $0.68 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 40 percent or $0.66 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 51 percent or $4.92 per bbl compared to 2007 mainly due to the higher U.S./Canadian dollar exchange rate, increased electricity 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 13,358 bbls/d in 2008 compared to 13,159 bbls/d in 2007 and from Canadian Foothills were 11,517 bbls/d in 2008 compared to 9,655 bbls/d in 2007. Average U.S. NGLs realized prices increased 82 percent to $94.14 per bbl in 2008 from $51.81 per bbl in 2007 and average Canadian Foothills NGLs realized prices increased 86 percent to $91.25 per bbl in 2008 from $49.09 per bbl in 2007, which are consistent with the higher WTI benchmark price.

IOCO

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. IOCo's operating segments will include the Integrated Oil and Canadian Plains Divisions.

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 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 June 30, 2008 versus 2007

Financial Results

($ millions)	Foster Creek/Christina Lake	
	2008	2007
Revenues, Net of Royalties	**$ 298**	$ 172
Expenses		
Transportation and selling	**123**	72
Operating	**50**	39
Operating Cash Flow	**$ 125**	$ 61

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	$ 172	112	(36)	50	**298**

(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 expense.

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

- A 138 percent increase in crude oil prices, excluding financial hedges;

offset by:

- Realized financial hedging losses of $35 million or $15.12 per bbl in 2008 compared to losses of $3 million or $1.06 per bbl in 2007; and
- Lower 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]	**$ 93.64**	$ 39.40
Expenses		
Transportation and selling	**2.77**	3.62
Operating	**21.41**	14.02
Netback	**$ 69.46**	$ 21.76
Crude Oil Production Volumes *(bbls/d)*	**24,671**	27,994

(1) Excludes the impact of realized financial hedging.

Foster Creek/Christina Lake crude oil prices in 2008 increased 138 percent compared to 2007. This increase reflects 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 83 percent in 2008 compared to 71 percent in 2007.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2008 decreased 23 percent or $0.85 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 53 percent or $7.39 per bbl in 2008 compared to 2007. The increase is mainly due to increased purchased fuel costs, staff levels, workovers, repairs and maintenance associated with the plant turnaround at Foster Creek and higher long-term compensation costs due to the increase in the EnCana share price. In addition, operating costs for 2008 compared to 2007 were impacted by the higher U.S./Canadian dollar exchange rate.

Six Months Ended June 30, 2008 versus 2007

Financial Results

($ millions)	Foster Creek/Christina Lake	
	2008	2007
Revenues, Net of Royalties	**$ 536**	$ 392
Expenses		
Transportation and selling	**243**	196
Operating	**91**	88
Operating Cash Flow	**$ 202**	$ 108

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	$ 392	147	(55)	52	**536**

(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 expense.

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

- A 110 percent increase in crude oil prices, excluding financial hedges;

offset by:

- Realized financial hedging losses of $58 million or $12.09 per bbl in 2008 compared to gains of $6 million or $1.14 per bbl in 2007; and
- Lower 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]	**$ 76.10**	$ 36.28
Expenses		
Transportation and selling	**2.74**	3.33
Operating	**18.94**	15.60
Netback	**$ 54.42**	$ 17.35
Crude Oil Production Volumes *(bbls/d)*	**27,024**	25,645

(1) Excludes the impact of realized financial hedging.

Foster Creek/Christina Lake crude oil prices in 2008 increased 110 percent compared to 2007. This increase reflects 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 81 percent in 2008 compared to 71 percent in 2007.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2008 decreased 18 percent or $0.59 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 $3.34 per bbl in 2008 compared to 2007. The increase is mainly due to increased purchased fuel costs, staff levels, workovers, repairs and maintenance associated with the plant turnaround at Foster Creek and higher long-term compensation costs due to the increase in the EnCana share price. In addition, operating costs for 2008 compared to 2007 were impacted by the higher U.S./Canadian dollar exchange rate.

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 67 MMcf/d in the second quarter of 2008 compared to 98 MMcf/d in the second quarter of 2007 and 66 MMcf/d in the six months of 2008 compared to 95 MMcf/d in the six months of 2007. Production volumes from Senlac were 3,009 bbls/d in the second quarter of 2008 compared to 2,489 bbls/d in the second quarter of 2007 and 3,261 bbls/d in the six months of 2008 compared to 2,737 bbls/d in the six months of 2007.

Downstream Operations

Financial Results

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2008**	2007	**2008**	2007
Revenues	**$ 2,769**	$ 1,717	**$ 4,815**	$ 3,060
Expenses				
Operating	**127**	119	**259**	219
Purchased product	**2,300**	1,157	**4,121**	2,291
Operating Cash Flow	**$ 342**	$ 441	**$ 435**	$ 550

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 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 30,000 bbls/d of Western Canadian Select heavy crude.

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). During the first quarter of 2008, the refinery undertook scheduled maintenance on one of its gasoline producing units, a catalytic cracker, resulting in lower refinery utilization rates.

The goal of the downstream business is to refine in the aggregate at the Borger and Wood River refineries approximately 250,000 bbls/d of bitumen (on a 100 percent basis) by 2015 to primarily transportation fuels. Currently, the refineries have processing capability to refine up to approximately 70,000 bbls/d of bitumen.

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 55 percent to $13.60 per bbl in the second quarter of 2008 compared to $30.12 per bbl in 2007 and decreased 50 percent to $10.65 per bbl in the six months of 2008 compared to $21.51 per bbl in 2007. Year-to-date operating cash flow includes an increase of $238 million (2007 - $55 million) related to lower purchased product costs as a result of accounting for inventory based on a first-in first-out valuation which is required under Canadian generally accepting accounting principles. This inventory valuation methodology results in lower product charges to operations in a rising input cost environment. 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 97 percent of that capacity during the second quarter of 2008 compared to 88 percent in 2007 and 94 percent during the six months of 2008 compared to 92 percent in 2007. Refinery crude utilization was lower in the second quarter of 2007 due to the planned turnaround and coker startup at the Borger refinery. Refined products averaged 464,000 bbls/d (232,000 bbls/d net to EnCana) in the second quarter of 2008 compared to 421,000 bbls/d (210,500 bbls/d net to EnCana) in 2007 and 450,000 bbls/d (225,000 bbls/d net to EnCana) in the six months of 2008 compared to 439,000 bbls/d (219,500 bbls/d net to EnCana) in 2007.

Purchased products, consisting mainly of crude oil, represented 95 percent of total expenses in the second quarter of 2008 compared to 91 percent in 2007 and 94 percent of total expenses in the six months of 2008 compared to 91 percent in 2007. Operating costs for labour, utilities and supplies comprised the balance of expenses. Revenues and purchased product have increased 61 percent and 99 percent, respectively, in line with the significant increase in crude oil prices experienced in the quarter and the reduced refining margins.

CANADIAN PLAINS

Produced Gas

Three Months Ended June 30, 2008 versus 2007

Financial Results

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

	2008	**2008 $/Mcf**	2007	2007 $/Mcf
Revenues, Net of Royalties / Price	**$ 739**	**$ 9.50**	$ 529	$ 6.66
Realized Financial Hedging Gain (Loss)	**(110)**		34	
Expenses				
Production and mineral taxes	**13**	**0.17**	10	0.14
Transportation and selling	**18**	**0.22**	21	0.26
Operating	**74**	**0.96**	55	0.69
Operating Cash Flow / Netback (1)	**$ 524**	**$ 8.15**	$ 477	$ 5.57
Netback including Realized Financial Hedging		**$ 6.73**		$ 6.00
Gas Production Volumes *(MMcf/d)*		**856**		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)	Revenue Variances in: Volume	**2008 Revenues Net of Royalties**
Canadian Plains	$ 563	$ 79	$ (13)	**$ 629**

(1) Includes the impact of realized financial hedging.

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

- A 43 percent increase in natural gas prices, excluding the impact of financial hedging;

offset by:

- A 2 percent decrease in natural gas production volumes; and

- Realized financial hedging losses of $110 million or $1.42 per Mcf in 2008 compared to gains of $34 million or $0.43 per Mcf in 2007.

Produced gas volumes decreased 2 percent in 2008 compared to 2007. 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. Variability in realized prices also reflects the weighting of EnCana's various gas stream volumes at their respective benchmark price, net of applicable basis differential.

Natural gas per unit production and mineral taxes increased in 2008 compared to 2007 for the Canadian Plains primarily due to the higher U.S./Canadian dollar exchange rate and higher natural gas prices.

Natural gas per unit transportation and selling costs decreased 15 percent or $0.04 per Mcf in 2008 compared to 2007 due to lower average transportation tolls offset partially by the higher U.S./Canadian dollar exchange rate.

Natural gas per unit operating expenses for the Canadian Plains in 2008 were 39 percent or $0.27 per Mcf higher than in 2007 primarily as a result of higher long-term compensation costs due to the increase in the EnCana share price and the higher U.S./Canadian dollar exchange rate as well as higher repairs and maintenance, property tax and lease costs and salaries and benefits expenses.

Six Months Ended June 30, 2008 versus 2007

Financial Results

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

	2008				2007			
				$/Mcf				**$/Mcf**
Revenues, Net of Royalties / Price	**$**	**1,302**	**$**	**8.34**	$	1,031	$	6.46
Realized Financial Hedging Gain (Loss)		**(83)**				90		
Expenses								
Production and mineral taxes		**18**		**0.12**		20		0.13
Transportation and selling		**37**		**0.24**		43		0.26
Operating		**147**		**0.94**		107		0.67
Operating Cash Flow / Netback [1]	**$**	**1,017**	**$**	**7.04**	$	951	$	5.40
Netback including Realized Financial Hedging			**$**	**6.51**			$	5.97
Gas Production Volumes *(MMcf/d)*				**857**				882

(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	$ 1,121	$ 127	$ (29)	**$ 1,219**

(1) Includes the impact of realized financial hedging.

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

- A 29 percent increase in natural gas prices, excluding the impact of financial hedging;

offset by:

- A 3 percent decrease in natural gas production volumes; and
- Realized financial hedging losses of $83 million or $0.53 per Mcf in 2008 compared to gains of $90 million or $0.57 per Mcf in 2007.

Produced gas volumes decreased 3 percent in 2008 compared to 2007. 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. Variability in realized prices also reflects the weighting of EnCana's various gas stream volumes at their respective benchmark price, net of applicable basis differential.

Natural gas per unit transportation and selling costs decreased 8 percent or $0.02 per Mcf in 2008 compared to 2007 due to lower average transportation tolls offset partially by the higher U.S./Canadian dollar exchange rate.

Natural gas per unit operating expenses for the Canadian Plains in 2008 were 40 percent or $0.27 per Mcf higher than in 2007 primarily as a result of the higher U.S./Canadian dollar exchange rate and higher long-term compensation costs due to the increase in the EnCana share price as well as higher repairs and maintenance, property tax and lease costs and salaries and benefits expenses.

Crude Oil and NGLs

Three Months Ended June 30, 2008 versus 2007

Financial Results

($ millions)	Canadian Plains	
	2008	2007
Revenues, Net of Royalties	**$ 554**	$ 286
Expenses		
Production and mineral taxes	**11**	8
Transportation and selling	**7**	7
Operating	**72**	52
Operating Cash Flow	**$ 464**	$ 219

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	$ 286	$ 297	$ (29)	**$ 554**

(1) Includes the impact of realized financial hedging.

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

- A 122 percent increase in crude oil prices and 72 percent increase in NGLs prices, excluding financial hedges;

offset by:

- Realized financial hedging losses on liquids of $70 million or $11.43 per bbl in 2008 compared to losses of $11 million or $1.69 per bbl in 2007.

Production from the Pelican Lake key resource play in the second quarter of 2008 was 21,434 bbls/d, down 5 percent compared to 2007 mainly due to facility down time during the quarter related to downstream pipeline disruptions and related oil treating interruptions. Production from the Weyburn key resource play of 13,180 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 13,207 bbls/d was down 17 percent mainly due to natural declines. Overall, Canadian Plains crude oil production decreased 7 percent.

Per Unit Results – Crude Oil

($ per barrel)	Canadian Plains	
	2008	2007
Price (1)	**$ 102.55**	$ 46.14
Expenses		
Production and mineral taxes	**1.78**	1.13
Transportation and selling	**1.45**	1.23
Operating	**12.11**	8.27
Netback	**$ 87.21**	$ 35.51
Crude Oil Production Volumes *(bbls/d)*	**65,097**	70,148

(1) Excludes the impact of realized financial hedging.

Canadian Plains crude oil prices in 2008 increased 122 percent compared to 2007. The increase reflects the changes in benchmark WTI and WCS crude oil prices. Total realized financial hedging losses on crude oil for Canadian Plains were approximately $69 million or $11.44 per bbl in 2008 compared to losses of approximately $11 million or $1.69 per bbl in 2007.

Canadian Plains crude oil per unit production and mineral taxes increased 58 percent or $0.65 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 18 percent or $0.22 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 offset by lower clean oil trucking costs at Weyburn in 2008.

Canadian Plains crude oil per unit operating costs in 2008 increased 46 percent or $3.84 per bbl compared to 2007 mainly due to the higher U.S./Canadian dollar exchange rate, higher long-term compensation costs due to the increase in the EnCana share price and increased property tax and lease costs, salaries and benefits expenses, workovers, repairs and maintenance and chemical costs 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 1,189 bbls/d in 2008 compared to 1,206 bbls/d in 2007. NGLs realized prices increased 72 percent to $96.34 per bbl in 2008 from $56.08 per bbl in 2007, which is consistent with the higher WTI benchmark price.

Six Months Ended June 30, 2008 versus 2007

Financial Results

($ millions)	Canadian Plains	
	2008	2007
Revenues, Net of Royalties	**$ 1,021**	$ 573
Expenses		
Production and mineral taxes	**19**	15
Transportation and selling	**15**	15
Operating	**140**	100
Operating Cash Flow	**$ 847**	$ 443

Crude Oil and NGLs Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Revenue Variances in: Volume	**2008 Revenues Net of Royalties**
Canadian Plains	$ 573	$ 485	$ (37)	**$ 1,021**

(1) Includes the impact of realized financial hedging.

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

- A 107 percent increase in crude oil prices and 66 percent increase in NGLs prices, excluding financial hedges;

offset by:

- Realized financial hedging losses on liquids of $106 million or $8.43 per bbl in 2008 compared to gains of $5 million or $0.40 per bbl in 2007.

Production from the Pelican Lake key resource play in the six months of 2008 was 22,669 bbls/d, essentially unchanged from 2007. Production from the Weyburn key resource play of 13,580 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 13,675 bbls/d was down 15 percent mainly due to natural declines. Overall, Canadian Plains crude oil production decreased 6 percent.

Per Unit Results – Crude Oil

($ per barrel)	Canadian Plains	
	2008	2007
Price [1]	**$ 89.58**	$ 43.34
Expenses		
Production and mineral taxes	**1.52**	1.15
Transportation and selling	**1.34**	1.22
Operating	**11.38**	7.84
Netback	**$ 75.34**	$ 33.13
Crude Oil Production Volumes *(bbls/d)*	**67,439**	71,387

(1) Excludes the impact of realized financial hedging.

Canadian Plains crude oil prices in 2008 increased 107 percent compared to 2007. The increase reflects the changes in benchmark WTI and WCS crude oil prices. Total realized financial hedging losses on crude oil for Canadian Plains were approximately $105 million or $8.45 per bbl in 2008 compared to gains of approximately $5 million or $0.40 per bbl in 2007.

Canadian Plains crude oil per unit production and mineral taxes increased 32 percent or $0.37 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 10 percent or $0.12 per bbl in 2008 compared to 2007 due to the higher U.S./Canadian dollar exchange rate partially offset by lower clean oil trucking costs.

Canadian Plains crude oil per unit operating costs in 2008 increased 45 percent or $3.54 per bbl compared to 2007 mainly due to the higher U.S./Canadian dollar exchange rate, higher long-term compensation costs due to the increase in the EnCana share price and increased workovers, property tax and lease costs, salaries and benefits expenses, chemical costs and repairs and maintenance 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 1,226 bbls/d in 2008 compared to 1,204 bbls/d in 2007. NGLs realized prices increased 66 percent to $85.40 per bbl in 2008 from $51.42 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 June 30, 2008 versus 2007

Upstream DD&A expenses of $1,026 million in the second quarter of 2008 increased $190 million or 23 percent compared to 2007 due to:

- Production volumes increased 7 percent;
- DD&A rates in 2008 for the U.S. are higher 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 an impairment of $35 million related to exploration prospects in Qatar.

Six Months Ended June 30, 2008 versus 2007

Upstream DD&A expenses of $1,992 million in the six months of 2008 increased $370 million or 23 percent compared to 2007 due to:

- Production volumes increased 8 percent;
- DD&A rates in 2008 for the U.S. are higher 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 an impairment of $35 million related to exploration prospects in Qatar.

Downstream DD&A

Downstream refining DD&A was $44 million in the second quarter of 2008 compared to $38 million in 2007 and $88 million in the six months of 2008 compared to $74 million in 2007.

MARKET OPTIMIZATION

Financial Results

($ millions)	Three Months Ended June 30 2008	Three Months Ended June 30 2007	Six Months Ended June 30 2008	Six Months Ended June 30 2007
Revenues	**$ 647**	$ 722	**$ 1,272**	$ 1,478
Expenses				
Transportation and selling	**-**	2	**-**	10
Operating	**8**	10	**19**	17
Purchased product	**628**	702	**1,235**	1,434
Operating Cash Flow	**11**	8	**18**	17
Depreciation, depletion and amortization	**4**	4	**8**	7
Segment Income	**$ 7**	$ 4	**$ 10**	$ 10

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 $2,790 million for the six months of 2008 compared to $2,184 million in 2007.

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

CORPORATE

Financial Results

($ millions)	Three Months Ended June 30 2008	Three Months Ended June 30 2007	Six Months Ended June 30 2008	Six Months Ended June 30 2007
Revenues	**$ (328)**	$ 49	**$ (1,424)**	$ (566)
Expenses				
Operating	**(7)**	(7)	**(9)**	(8)
Depreciation, depletion and amortization	**23**	21	**44**	39
Segment Income (Loss)	**$ (344)**	$ 35	**$ (1,459)**	$ (597)

Revenues 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 Corporate Expenses

($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2008	2007	**2008**	2007
Administrative	**$ 225**	$ 95	**$ 381**	$ 190
Interest, net	**147**	94	**281**	195
Accretion of asset retirement obligation	**20**	15	**41**	29
Foreign exchange (gain) loss, net	**(35)**	7	**60**	(5)
(Gain) loss on divestitures	**(17)**	1	**(17)**	(58)

Administrative expenses increased $130 million in the second quarter and $191 million in the six months of 2008 compared to the same periods in 2007. The year-to-date increase was primarily due to higher long-term compensation expenses of $92 million as a result of the increase in the EnCana share price, higher staff levels and other related costs due to growth of $32 million and a one time charge of $23 million for the settlement of a class action lawsuit as described in the Contractual Obligations and Contingencies section of this MD&A. The higher U.S./Canadian dollar exchange rate added an additional $20 million. EnCana also recorded $24 million related to the proposed corporate reorganization.

Net interest expense in the six months of 2008 increased $86 million from 2007 primarily as a result of higher average outstanding debt. EnCana's total long-term debt, including current portion, increased $2,943 million to $10,369 million at June 30, 2008 compared with $7,426 million at June 30, 2007 primarily due to the Deep Bossier acquisition. EnCana's year-to-date weighted average interest rate on outstanding debt was 5.5 percent in 2008 compared to 5.6 percent in 2007.

The foreign exchange loss of $60 million in six 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 2007 relates to the divestiture of interests in Chad.

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

($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2008	2007	**2008**	2007
Revenues				
Natural Gas	**$ (208)**	$ 71	**$ (1,321)**	$ (484)
Crude Oil	**(120)**	(22)	**(103)**	(82)
	(328)	49	**(1,424)**	(566)
Expenses	**(10)**	(6)	**(13)**	(7)
	(318)	55	**(1,411)**	(559)
Income Tax Expense (Recovery)	**(83)**	8	**(439)**	(183)
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ (235)**	$ 47	**$ (972)**	$ (376)

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 gain or loss 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 six months ended June 30, 2008 was 40.0 percent compared to 22.0 percent in 2007. The majority of the difference is due to a $173 million future tax charge in 2008 related to unrealized foreign exchange not included in net earnings, and a $231 million tax recovery in 2007 related to a tax legislative change.

Cash taxes were $440 million in the second quarter of 2008 compared to $285 million in 2007. Cash taxes for the six months ended June 30, 2008 were $804 million compared to $660 million in 2007. The increase in cash tax is primarily due to the increase in operating cash flow.

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 the amount of net earnings before income taxes for the year and the magnitude of the items representing "permanent differences" that are excluded from the earnings, which are subject to tax, either current or future. There are a variety of items of this type, including:

- The effects of asset divestitures where the tax values of the assets sold differ from their accounting values;

- Adjustments for changes to tax rates and other tax legislation, which have an impact on future income tax obligations;
- The non-taxable half of Canadian capital gains or losses; and
- Items where the income tax treatment is different from the accounting treatment.

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 EnCana's Business section of this MD&A occurs, it will result in an acceleration of future taxes for Canadian operations that will be recognized in the fourth quarter of 2008. The impact on 2008 cash taxes is expected to be an increase of approximately $1 billion. This is anticipated to be offset by a U.S. tax benefit which will accrue to GasCo in 2010 and subsequent years as a result of returning to independent producer status. The expected net present value of the tax cost of the restructuring is approximately $250 million.

NET CAPITAL INVESTMENT

Capital Summary

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2008**	2007	**2008**	2007
Canadian Plains	**$ 158**	$ 156	**$ 420**	$ 340
Canadian Foothills	**570**	404	**1,337**	1,052
United States	**660**	422	**1,179**	861
Integrated Oil	**266**	126	**529**	270
Offshore and International	**28**	44	**53**	62
Market Optimization	**5**	2	**7**	3
Corporate	**31**	18	**42**	67
Capital Investment	**1,718**	1,172	**3,567**	2,655
Acquisitions	**278**	17	**336**	24
Divestitures	**(79)**	(165)	**(151)**	(446)
Net Capital Investment	**$ 1,917**	$ 1,024	**$ 3,752**	$ 2,233

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

Capital investment during the six 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. As disclosed in the Foreign Exchange section of this MD&A, capital expenditures were also influenced by the rise in the average U.S./Canadian dollar exchange rate, which increased Capital Investment by $57 million in the second quarter of 2008 and $220 million in the six months of 2008.

GasCo
Canadian Foothills and United States Capital Investment

The $603 million increase in Canadian Foothills and U.S. capital investment in the six months of 2008 compared to the same period in 2007 was primarily due to:

- Canadian Foothills capital investment of $1,337 million in the six months of 2008 increased $285 million primarily due to:
  - The rise in the average U.S./Canadian dollar exchange rate that increased capital by $144 million and higher capitalized costs for long-term compensation expenses; and
  - Drilling, completion and facilities costs increased due to increased focus on well tie-ins, revised completion techniques and a gas processing facility expansion. The Company drilled 473 net wells in the six months of 2008 compared to 693 net wells in 2007.
- U.S. capital investment of $1,179 million in the six months of 2008 increased $318 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 and higher capitalized costs for long-term compensation expenses. The number of net wells drilled in the U.S. increased to 370 from 339 in 2007.

IOCo

Integrated Oil and Canadian Plains Capital Investment

The $339 million increase in Integrated Oil and Canadian Plains capital investment in the six months of 2008 compared to the same period in 2007 was primarily due to:

- Integrated Oil capital investment of $529 million during the six 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 $259 million increase in Integrated Oil capital investment in the six months of 2008 compared to the same period in 2007 was primarily due to higher facility costs at Foster Creek and Christina Lake. Facility expenditures at Foster Creek will increase plant capacity to 120,000 bbls/d to accommodate Phases D and E expansion. Christina Lake facility costs will 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 180 additional stratigraphic test wells (90 net to EnCana) at Foster Creek and Christina Lake related to the next phases of development compared to the same period in 2007. The rise in the average U.S./Canadian dollar exchange rate increased Integrated Oil capital by $19 million. Integrated Oil capital investment was also impacted by higher capitalized costs for long-term compensation expenses.

- Canadian Plains capital investment of $420 million in the six months of 2008 increased $80 million primarily due to the rise in the average U.S./Canadian dollar exchange rate that increased capital by $44 million and higher capitalized costs for long-term compensation expenses. The Company drilled 680 net wells in the six months of 2008 compared to 781 net wells in 2007, focusing on more 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 $245 million in the Haynesville Shale play in Louisiana during the six months of 2008 and minor property acquisitions in 2007.

In September 2007, EnCana signed an agreement to sell its remaining interests in Brazil for approximately $165 million before closing adjustments. The sale is subject to closing conditions and regulatory approvals, and was initially anticipated to be completed in the first quarter of 2008. As a result of various unexpected issues, including a labour dispute within the regulator in Brazil, expected approval of this transaction has been delayed. The timing of the formal approval by the regulator cannot be determined with certainty at this time, but is expected to occur in 2008.

EnCana completed the following significant divestitures in the six months of 2007:

- 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 $207 million resulting in a gain on sale of $59 million; and
- The sale of The Bow office project assets for approximately $57 million, largely representing its investment at the date of sale.

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

Liquidity and Capital Resources

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2008**	2007	**2008**	2007
Net cash provided by (used in)				
Operating activities	**$ 1,996**	$ 2,148	**$ 3,754**	$ 4,056
Investing activities	**(2,036)**	(1,094)	**(3,570)**	(2,342)
Financing activities	**(72)**	(841)	**44**	(1,567)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**1**	5	**(3)**	6
Increase (decrease) in cash and cash equivalents	**$ (111)**	$ 218	**$ 225**	$ 153

Operating Activities

Cash Flow was $2,889 million during the second quarter of 2008 compared to $2,549 million for the same period in 2007. On a year-to-date basis, Cash Flow was $5,278 million compared to $4,301 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 an increase in the risk management liability offset by an increase in inventory and decrease in income tax payable.

Investing Activities

Net cash used for investing activities in the six months of 2008 increased $1,228 million compared to the same period in 2007. Capital expenditures, including property acquisitions, in the six months of 2008 increased $1,224 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 six months of 2008 was $894 million compared to net issuance of $394 million for the same period in 2007. EnCana's debt adjusted for working capital ("net debt") was $11,964 million as at June 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.

As at June 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 $7.2 billion. Of this unused shelf capacity, $2.0 billion expired on July 9, 2008.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the Company's announcement to split into two highly 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".

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under a NCIB. During the second quarter of 2008, EnCana purchased 0.2 million of its Common Shares for total consideration of $15 million compared with approximately 12 million Common Shares for total consideration of $713 million for the same period in 2007. During the six months of 2008, EnCana purchased 4.8 million of its Common Shares for total consideration of $326 million compared with 35.4 million Common Shares for total consideration of $1,807 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 six months ended June 30, 2008 totaled $600 million compared with $304 million for the same period in 2007. These dividends were funded by Cash Flow.

Financial Metrics

	June 30 2008	December 31 2007
Net Debt to Capitalization (1)	**36%**	34%
Net Debt to Adjusted EBITDA (2)	**1.3x**	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 gain 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 increased to 36 percent from 34 percent at December 31, 2007 primarily due to unrealized mark-to-market losses on risk management instruments which increased Net Debt. Excluding this impact, the Net Debt to Capitalization ratio would have been 34 percent at June 30, 2008 and would have remained unchanged at 34 percent at December 31, 2007.

Free Cash Flow

EnCana's second quarter 2008 Free Cash Flow decreased $206 million and six months of 2008 Free Cash Flow increased $65 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 June 30		Six Months Ended June 30	
($ millions)	2008	2007	2008	2007
Cash Flow (1)	**$ 2,889**	$ 2,549	**$ 5,278**	$ 4,301
Capital Investment	**1,718**	1,172	**3,567**	2,655
Free Cash Flow (2)	**$ 1,171**	$ 1,377	**$ 1,711**	$ 1,646

(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)	June 30 2008	December 31 2007
Common Shares outstanding, beginning of year	**750.2**	777.9
Common Shares issued under option plans	**2.8**	8.3
Common Shares purchased	**(2.8)**	(36.0)
Common Shares outstanding, end of period	**750.2**	750.2
Weighted average Common Shares outstanding – diluted	**752.3**	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 June 30, 2008 and 2007.

Employees have been granted options to purchase Common Shares under various plans. At June 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 June 30, 2008, approximately 32.9

million options with TSARs attached were outstanding, of which 9.8 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 June 30, 2008, approximately 2.6 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 $10,391 million at June 30, 2008 are $2,323 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. Further details regarding EnCana's long-term debt are described in Note 11 to the Interim Consolidated Financial Statements.

As at June 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 104 Bcf at a weighted average price of $4.34 per Mcf. As at June 30, 2008, these transactions had an unrealized loss of $522 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 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.

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 U.S. 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. There may be modifications introduced to the ARF prior to the implementation thereof.

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.

The Alberta Government has set targets for GHG emissions reductions of 14 percent below 2005 levels by 2050, with 70 percent of the reductions to come from carbon capture and storage. 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 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.

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.

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

EnCana plans to continue to focus principally on growing natural gas and crude oil production from unconventional resource plays in North America and on developing its high quality in-situ oil resources and expanding the Company's 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, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies. 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.

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 reviewing the existing organizational structures and determining the resources and corporate functions that are required for the proposed companies.

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 second quarter of 2008. EnCana's news release dated July 24, 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: 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; the expected timing of, and closing of, the sale of the Company's interests in Brazil; 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 expansion of the Company's downstream heavy oil processing capacity; 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; 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: 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; 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 July 24, 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. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $1.00 for every Canadian dollar.

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 June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
REVENUES, NET OF ROYALTIES	*(Note 5)*	**$ 7,321**	$ 5,613	**$ 12,663**	$ 10,049
EXPENSES	*(Note 5)*				
Production and mineral taxes		**154**	57	**268**	149
Transportation and selling		**326**	234	**646**	512
Operating		**709**	565	**1,405**	1,116
Purchased product		**2,882**	1,836	**5,275**	3,687
Depreciation, depletion and amortization		**1,097**	899	**2,132**	1,742
Administrative		**225**	95	**381**	190
Interest, net	*(Note 7)*	**147**	94	**281**	195
Accretion of asset retirement obligation	*(Note 12)*	**20**	15	**41**	29
Foreign exchange (gain) loss, net	*(Note 8)*	**(35)**	7	**60**	(5)
(Gain) loss on divestitures	*(Note 6)*	**(17)**	1	**(17)**	(58)
		5,508	3,803	**10,472**	7,557
NET EARNINGS BEFORE INCOME TAX		**1,813**	1,810	**2,191**	2,492
Income tax expense	*(Note 9)*	**592**	364	**877**	549
NET EARNINGS		**$ 1,221**	$ 1,446	**$ 1,314**	$ 1,943
NET EARNINGS PER COMMON SHARE	*(Note 16)*				
Basic		**$ 1.63**	$ 1.91	**$ 1.75**	$ 2.54
Diluted		**$ 1.63**	$ 1.89	**$ 1.75**	$ 2.51

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 13,082**	$ 11,344
Net Earnings		**1,314**	1,943
Dividends on Common Shares		**(600)**	(304)
Charges for Normal Course Issuer Bid	*(Note 13)*	**(243)**	(1,421)
RETAINED EARNINGS, END OF PERIOD		**$ 13,553**	$ 11,562

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME *(unaudited)*

($ millions)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
NET EARNINGS	**$ 1,221**	$ 1,446	**$ 1,314**	$ 1,943
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Foreign Currency Translation Adjustment	**48**	828	**(352)**	939
COMPREHENSIVE INCOME	**$ 1,269**	$ 2,274	**$ 962**	$ 2,882

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

($ millions)	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
ACCUMULATED OTHER COMPREHENSIVE INCOME, BEGINNING OF YEAR	**$ 3,063**	$ 1,375
Foreign Currency Translation Adjustment	**(352)**	939
ACCUMULATED OTHER COMPREHENSIVE INCOME, END OF PERIOD	**$ 2,711**	$ 2,314

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		As at June 30, 2008	As at December 31, 2007
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 778**	$ 553
Accounts receivable and accrued revenues		**3,346**	2,381
Current portion of partnership contribution receivable		**305**	297
Risk management	*(Note 17)*	**265**	385
Inventories	*(Note 10)*	**1,422**	828
		6,116	4,444
Property, Plant and Equipment, net	*(Note 5)*	**37,070**	35,865
Investments and Other Assets		**654**	607
Partnership Contribution Receivable		**2,992**	3,147
Risk Management	*(Note 17)*	**341**	18
Goodwill		**2,821**	2,893
	(Note 5)	**$ 49,994**	$ 46,974
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 4,888**	$ 3,982
Income tax payable		**909**	1,150
Current portion of partnership contribution payable		**297**	288
Risk management	*(Note 17)*	**1,617**	207
Current portion of long-term debt	*(Note 11)*	**491**	703
		8,202	6,330
Long-Term Debt	*(Note 11)*	**9,878**	8,840
Other Liabilities		**450**	242
Partnership Contribution Payable		**3,012**	3,163
Risk Management	*(Note 17)*	**73**	29
Asset Retirement Obligation	*(Note 12)*	**1,402**	1,458
Future Income Taxes		**6,160**	6,208
		29,177	26,270
Shareholders' Equity			
Share capital	*(Note 13)*	**4,553**	4,479
Paid in surplus		**-**	80
Retained earnings		**13,553**	13,082
Accumulated other comprehensive income		**2,711**	3,063
Total Shareholders' Equity		**20,817**	20,704
		$ 49,994	$ 46,974

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

($ millions)		Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
OPERATING ACTIVITIES					
Net earnings		**$ 1,221**	$ 1,446	**$ 1,314**	$ 1,943
Depreciation, depletion and amortization		**1,097**	899	**2,132**	1,742
Future income taxes	*(Note 9)*	**152**	79	**73**	(111)
Unrealized (gain) loss on risk management	*(Note 17)*	**318**	(55)	**1,411**	559
Unrealized foreign exchange (gain) loss		**(11)**	79	**65**	76
Accretion of asset retirement obligation	*(Note 12)*	**20**	15	**41**	29
(Gain) loss on divestitures	*(Note 6)*	**(17)**	1	**(17)**	(58)
Other		**109**	85	**259**	121
Net change in other assets and liabilities		**(171)**	(16)	**(264)**	4
Net change in non-cash working capital		**(722)**	(385)	**(1,260)**	(249)
Cash From Operating Activities		**1,996**	2,148	**3,754**	4,056
INVESTING ACTIVITIES					
Capital expenditures	*(Note 5)*	**(1,996)**	(1,189)	**(3,903)**	(2,679)
Proceeds from divestitures	*(Note 6)*	**79**	165	**151**	446
Net change in investments and other		**(18)**	(25)	**(9)**	(6)
Net change in non-cash working capital		**(101)**	(45)	**191**	(103)
Cash (Used in) Investing Activities		**(2,036)**	(1,094)	**(3,570)**	(2,342)
FINANCING ACTIVITIES					
Net issuance (repayment) of revolving long-term debt		**426**	(40)	**367**	(40)
Issuance of long-term debt	*(Note 11)*	**-**	-	**723**	434
Repayment of long-term debt		**(196)**	-	**(196)**	-
Issuance of common shares	*(Note 13)*	**13**	77	**76**	153
Purchase of common shares	*(Note 13)*	**(15)**	(713)	**(326)**	(1,807)
Dividends on common shares		**(300)**	(151)	**(600)**	(304)
Other		**-**	(14)	**-**	(3)
Cash From (Used in) Financing Activities		**(72)**	(841)	**44**	(1,567)
FOREIGN EXCHANGE GAIN (LOSS) ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**1**	5	**(3)**	6
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**(111)**	218	**225**	153
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**889**	337	**553**	402
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 778**	$ 555	**$ 778**	$ 555

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 highly focused energy companies - one a North American natural gas company and the other a fully integrated oil company with in-situ oilsands properties and refineries supplemented by reliable production from various gas and oil resource plays. The proposed corporate reorganization, expected to close in early January 2009, would 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 every EnCana shareholder receiving one share of each entity in exchange for each EnCana common share held. The working names of the two companies are GasCo and IntegratedOilCo ("IOCo") respectively. GasCo will retain the name of EnCana Corporation while the permanent name of IOCo will be determined prior to the close of the transaction.

5. SEGMENTED INFORMATION

As a result of the proposed corporate reorganization, 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.

GasCo's operating segments will include EnCana's Canadian Foothills, United States and Offshore and International segments. IOCo's operating segments will include EnCana's Canadian Plains and Integrated Oil segments.

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. Offshore and International exploration is mainly focused on opportunities in Atlantic Canada, the Middle East 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 June 30)

	Canadian Plains		Canadian Foothills		United States	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,185**	$ 853	**$ 1,189**	$ 917	**$ 1,525**	$ 1,128
Expenses						
Production and mineral taxes	**24**	18	**12**	13	**118**	26
Transportation and selling	**25**	28	**54**	51	**120**	77
Operating	**147**	108	**180**	125	**186**	154
Purchased product	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**238**	242	**285**	257	**421**	281
Segment Income (Loss)	**$ 751**	$ 457	**$ 658**	$ 471	**$ 680**	$ 590

	Integrated Oil		Offshore & International		Market Optimization	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 3,104**	$ 1,943	**$ (1)**	$ 1	**$ 647**	$ 722
Expenses						
Production and mineral taxes	**-**	-	**-**	-	**-**	-
Transportation and selling	**127**	76	**-**	-	**-**	2
Operating	**196**	176	**(1)**	(1)	**8**	10
Purchased product	**2,254**	1,134	**-**	-	**628**	702
Depreciation, depletion and amortization	**91**	94	**35**	-	**4**	4
Segment Income (Loss)	**$ 436**	$ 463	**$ (35)**	$ 2	**$ 7**	$ 4

	Corporate		Consolidated	
	2008	2007	**2008**	2007
Revenues, Net of Royalties	**$ (328)**	$ 49	**$ 7,321**	$ 5,613
Expenses				
Production and mineral taxes	**-**	-	**154**	57
Transportation and selling	**-**	-	**326**	234
Operating	**(7)**	(7)	**709**	565
Purchased product	**-**	-	**2,882**	1,836
Depreciation, depletion and amortization	**23**	21	**1,097**	899
Segment Income (Loss)	**$ (344)**	$ 35	**2,153**	2,022
Administrative			**225**	95
Interest, net			**147**	94
Accretion of asset retirement obligation			**20**	15
Foreign exchange (gain) loss, net			**(35)**	7
(Gain) loss on divestitures			**(17)**	1
			340	212
Net Earnings Before Income Tax			**1,813**	1,810
Income tax expense			**592**	364
Net Earnings			**$ 1,221**	$ 1,446

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 June 30)

Geographic and Product Information

Canadian Plains	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 629**	$ 563	**$ 554**	$ 286	**$ 2**	$ 4	**$ 1,185**	$ 853
Expenses								
Production and mineral taxes	**13**	10	**11**	8	**-**	-	**24**	18
Transportation and selling	**18**	21	**7**	7	**-**	-	**25**	28
Operating	**74**	55	**72**	52	**1**	1	**147**	108
Operating Cash Flow	**$ 524**	$ 477	**$ 464**	$ 219	**$ 1**	$ 3	**$ 989**	$ 699

Canadian Foothills	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,000**	$ 816	**$ 174**	$ 88	**$ 15**	$ 13	**$ 1,189**	$ 917
Expenses								
Production and mineral taxes	**11**	12	**1**	1	**-**	-	**12**	13
Transportation and selling	**51**	49	**3**	2	**-**	-	**54**	51
Operating	**163**	114	**12**	7	**5**	4	**180**	125
Operating Cash Flow	**$ 775**	$ 641	**$ 158**	$ 78	**$ 10**	$ 9	**$ 943**	$ 728

United States	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,308**	$ 989	**$ 130**	$ 70	**$ 87**	$ 69	**$ 1,525**	$ 1,128
Expenses								
Production and mineral taxes	**107**	20	**11**	6	**-**	-	**118**	26
Transportation and selling	**120**	77	**-**	-	**-**	-	**120**	77
Operating	**106**	85	**-**	-	**80**	69	**186**	154
Operating Cash Flow	**$ 975**	$ 807	**$ 119**	$ 64	**$ 7**	$ -	**$ 1,101**	$ 871

Integrated Oil	Oil		Downstream Refining		Other *		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 298**	$ 172	**$ 2,769**	$ 1,717	**$ 37**	$ 54	**$ 3,104**	$ 1,943
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**-**	-	**-**	-
Transportation and selling	**123**	72	**-**	-	**4**	4	**127**	76
Operating	**50**	39	**127**	119	**19**	18	**196**	176
Purchased product	**-**	-	**2,300**	1,157	**(46)**	(23)	**2,254**	1,134
Operating Cash Flow	**$ 125**	$ 61	**$ 342**	$ 441	**$ 60**	$ 55	**$ 527**	$ 557

* Includes exploration and production of natural gas and bitumen for 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 three months ended June 30)

Company Operating Information*

GasCo

	Canadian Foothills		United States		Offshore & International		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,189**	$ 917	**$ 1,525**	$ 1,128	**$ (1)**	$ 1	**$ 2,713**	$ 2,046
Expenses								
Production and mineral taxes	**12**	13	**118**	26	**-**	-	**130**	39
Transportation and selling	**54**	51	**120**	77	**-**	-	**174**	128
Operating	**180**	125	**186**	154	**(1)**	(1)	**365**	278
Operating Cash Flow	**$ 943**	$ 728	**$ 1,101**	$ 871	**$ -**	$ 2	**$ 2,044**	$ 1,601

IOCo

	Canadian Plains		Integrated Oil		Total	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,185**	$ 853	**$ 3,104**	$ 1,943	**$ 4,289**	$ 2,796
Expenses						
Production and mineral taxes	**24**	18	**-**	-	**24**	18
Transportation and selling	**25**	28	**127**	76	**152**	104
Operating	**147**	108	**196**	176	**343**	284
Purchased product	**-**	-	**2,254**	1,134	**2,254**	1,134
Operating Cash Flow	**$ 989**	$ 699	**$ 527**	$ 557	**$ 1,516**	$ 1,256

* GasCo and IOCo company operating information excluding their respective share of the Market Optimization and Corporate segments.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Results of Operations (For the six months ended June 30)

	Canadian Plains		Canadian Foothills		United States	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 2,244**	$ 1,700	**$ 2,264**	$ 1,781	**$ 2,879**	$ 2,091
Expenses						
Production and mineral taxes	**37**	35	**16**	24	**214**	90
Transportation and selling	**52**	58	**110**	98	**235**	143
Operating	**289**	209	**358**	254	**355**	301
Purchased product	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**483**	472	**560**	493	**818**	546
Segment Income (Loss)	**$ 1,383**	$ 926	**$ 1,220**	$ 912	**$ 1,257**	$ 1,011

	Integrated Oil		Offshore & International		Market Optimization	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 5,427**	$ 3,566	**$ 1**	$ (1)	**$ 1,272**	$ 1,478
Expenses						
Production and mineral taxes	**1**	-	**-**	-	**-**	-
Transportation and selling	**249**	203	**-**	-	**-**	10
Operating	**392**	341	**1**	2	**19**	17
Purchased product	**4,040**	2,253	**-**	-	**1,235**	1,434
Depreciation, depletion and amortization	**184**	184	**35**	1	**8**	7
Segment Income (Loss)	**$ 561**	$ 585	**$ (35)**	$ (4)	**$ 10**	$ 10

	Corporate		Consolidated	
	2008	2007	**2008**	2007
Revenues, Net of Royalties	**$ (1,424)**	$ (566)	**$ 12,663**	$ 10,049
Expenses				
Production and mineral taxes	**-**	-	**268**	149
Transportation and selling	**-**	-	**646**	512
Operating	**(9)**	(8)	**1,405**	1,116
Purchased product	**-**	-	**5,275**	3,687
Depreciation, depletion and amortization	**44**	39	**2,132**	1,742
Segment Income (Loss)	**$ (1,459)**	$ (597)	**2,937**	2,843
Administrative			**381**	190
Interest, net			**281**	195
Accretion of asset retirement obligation			**41**	29
Foreign exchange (gain) loss, net			**60**	(5)
(Gain) loss on divestitures			**(17)**	(58)
			746	351
Net Earnings Before Income Tax			**2,191**	2,492
Income tax expense			**877**	549
Net Earnings			**$ 1,314**	$ 1,943

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Results of Operations (For the six months ended June 30)

Geographic and Product Information

Canadian Plains

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,219**	$ 1,121	**$ 1,021**	$ 573	**$ 4**	$ 6	**$ 2,244**	$ 1,700
Expenses								
Production and mineral taxes	**18**	20	**19**	15	**-**	-	**37**	35
Transportation and selling	**37**	43	**15**	15	**-**	-	**52**	58
Operating	**147**	107	**140**	100	**2**	2	**289**	209
Operating Cash Flow	**$ 1,017**	$ 951	**$ 847**	$ 443	**$ 2**	$ 4	**$ 1,866**	$ 1,398

Canadian Foothills

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 1,909**	$ 1,587	**$ 322**	$ 168	**$ 33**	$ 26	**$ 2,264**	$ 1,781
Expenses								
Production and mineral taxes	**14**	23	**2**	1	**-**	-	**16**	24
Transportation and selling	**104**	94	**6**	4	**-**	-	**110**	98
Operating	**324**	231	**23**	14	**11**	9	**358**	254
Operating Cash Flow	**$ 1,467**	$ 1,239	**$ 291**	$ 149	**$ 22**	$ 17	**$ 1,780**	$ 1,405

United States

	Gas		Oil & NGLs		Other		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 2,491**	$ 1,820	**$ 229**	$ 124	**$ 159**	$ 147	**$ 2,879**	$ 2,091
Expenses								
Production and mineral taxes	**194**	78	**20**	12	**-**	-	**214**	90
Transportation and selling	**235**	143	**-**	-	**-**	-	**235**	143
Operating	**207**	160	**-**	-	**148**	141	**355**	301
Operating Cash Flow	**$ 1,855**	$ 1,439	**$ 209**	$ 112	**$ 11**	$ 6	**$ 2,075**	$ 1,557

Integrated Oil

	Oil		Downstream Refining		Other *		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 536**	$ 392	**$ 4,815**	$ 3,060	**$ 76**	$ 114	**$ 5,427**	$ 3,566
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**1**	-	**1**	-
Transportation and selling	**243**	196	**-**	-	**6**	7	**249**	203
Operating	**91**	88	**259**	219	**42**	34	**392**	341
Purchased product	**-**	-	**4,121**	2,291	**(81)**	(38)	**4,040**	2,253
Operating Cash Flow	**$ 202**	$ 108	**$ 435**	$ 550	**$ 108**	$ 111	**$ 745**	$ 769

* Includes exploration and production of natural gas and bitumen for 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 six months ended June 30)

Company Operating Information*

	GasCo							
	Canadian Foothills		United States		Offshore & International		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 2,264**	$ 1,781	**$ 2,879**	$ 2,091	**$ 1**	$ (1)	**$ 5,144**	$ 3,871
Expenses								
Production and mineral taxes	**16**	24	**214**	90	**-**	-	**230**	114
Transportation and selling	**110**	98	**235**	143	**-**	-	**345**	241
Operating	**358**	254	**355**	301	**1**	2	**714**	557
Operating Cash Flow	**$ 1,780**	$ 1,405	**$ 2,075**	$ 1,557	**$ -**	$ (3)	**$ 3,855**	$ 2,959

	IOCo					
	Canadian Plains		Integrated Oil		Total	
	2008	2007	**2008**	2007	**2008**	2007
Revenues, Net of Royalties	**$ 2,244**	$ 1,700	**$ 5,427**	$ 3,566	**$ 7,671**	$ 5,266
Expenses						
Production and mineral taxes	**37**	35	**1**	-	**38**	35
Transportation and selling	**52**	58	**249**	203	**301**	261
Operating	**289**	209	**392**	341	**681**	550
Purchased product	**-**	-	**4,040**	2,253	**4,040**	2,253
Operating Cash Flow	**$ 1,866**	$ 1,398	**$ 745**	$ 769	**$ 2,611**	$ 2,167

* GasCo and IOCo company operating information excluding their respective share of the Market Optimization and Corporate segments.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. SEGMENTED INFORMATION (continued)

Capital Expenditures

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Capital				
Canadian Plains	**$ 158**	$ 156	**$ 420**	$ 340
Canadian Foothills	**570**	404	**1,337**	1,052
United States	**660**	422	**1,179**	861
Integrated Oil	**266**	126	**529**	270
Offshore & International	**28**	44	**53**	62
Market Optimization	**5**	2	**7**	3
Corporate	**31**	18	**42**	67
	1,718	1,172	**3,567**	2,655
Acquisition Capital				
Canadian Foothills	**20**	-	**92**	7
United States	**258**	3	**244**	3
Integrated Oil	**-**	14	**-**	14
	278	17	**336**	24
Total	**$ 1,996**	$ 1,189	**$ 3,903**	$ 2,679

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 Variable Interest Entity ("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.

Property, Plant and Equipment and Total Assets by Segment

	Property, Plant and Equipment As at		Total Assets As at	
	June 30, 2008	December 31, 2007	**June 30, 2008**	December 31, 2007
Canadian Plains	**$ 6,675**	$ 6,967	**$ 8,413**	$ 8,626
Canadian Foothills	**10,611**	10,127	**12,757**	12,184
United States	**12,385**	11,879	**13,831**	12,948
Integrated Oil	**5,462**	5,164	**10,976**	10,122
Offshore & International	**1,229**	1,104	**1,331**	1,135
Market Optimization	**165**	171	**656**	478
Corporate	**543**	453	**2,030**	1,481
Total	**$ 37,070**	$ 35,865	**$ 49,994**	$ 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 June 30, 2008, Corporate Property, Plant and Equipment and Total Assets includes EnCana's accrual to date of $232 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 June 30, 2008, Offshore and International Property, Plant, and Equipment and Total Assets includes EnCana's accrual to date of $91 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.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. DIVESTITURES

Total year-to-date proceeds received on sale of assets and investments were $151 million (2007 - $446 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 $31 million (2007 - nil) in Canadian Plains, $70 million (2007 - $12 million) in Canadian Foothills, and $95 million (2007 - $11 million) in the United States.

Offshore and International
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 $207 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.

7. INTEREST, NET

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Interest Expense - Long-Term Debt	**$ 144**	$ 118	**$ 284**	$ 218
Interest Expense - Other *	**56**	43	**110**	106
Interest Income *	**(53)**	(67)	**(113)**	(129)
	$ 147	$ 94	**$ 281**	$ 195

* 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 June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**$ (52)**	$ (289)	**$ 165**	$ (330)
Translation of U.S. dollar partnership contribution receivable issued from Canada	**44**	305	**(99)**	343
Other Foreign Exchange (Gain) Loss	**(27)**	(9)	**(6)**	(18)
	$ (35)	$ 7	**$ 60**	$ (5)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Current				
Canada	**$ 172**	$ 61	**$ 406**	$ 343
United States	**256**	220	**385**	312
Other Countries	**12**	4	**13**	5
Total Current Tax	**440**	285	**804**	660
Future	**152**	79	**73**	(111)
	$ 592	$ 364	**$ 877**	$ 549

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Net Earnings Before Income Tax	**$ 1,813**	$ 1,810	**$ 2,191**	$ 2,492
Canadian Statutory Rate	**29.7%**	32.3%	**29.7%**	32.3%
Expected Income Tax	**538**	585	**650**	805
Effect on Taxes Resulting from:				
Statutory and other rate differences	**75**	19	**78**	24
Effect of tax rate changes*	**-**	(37)	**-**	(37)
Effect of legislative changes	**-**	(231)	**-**	(231)
Non-taxable downstream partnership income	**(8)**	(13)	**(7)**	(19)
International financing	**(79)**	(14)	**(159)**	(29)
Foreign exchange gains not included in net earnings	**24**	-	**180**	-
Non-taxable capital (gains) losses	**(4)**	8	**11**	(12)
Other	**46**	47	**124**	48
	$ 592	$ 364	**$ 877**	$ 549
Effective Tax Rate	**32.7%**	20.1%	**40.0%**	22.0%

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

10. INVENTORIES

	As at June 30, 2008	As at December 31, 2007
Product		
Canadian Plains	**$ 1**	$ -
United States	**-**	2
Integrated Oil	**1,092**	646
Market Optimization	**327**	180
Parts and Supplies	**2**	-
	$ 1,422	$ 828

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. LONG-TERM DEBT

	As at June 30, 2008	As at December 31, 2007
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 1,673**	$ 1,506
Unsecured notes	**1,718**	1,138
	3,391	2,644
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**650**	495
Unsecured notes	**6,350**	6,421
	7,000	6,916
Increase in Value of Debt Acquired *	**61**	66
Debt Discounts and Financing Costs	**(83)**	(83)
Current Portion of Long-Term Debt	**(491)**	(703)
	$ 9,878	$ 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 June 30, 2008	As at December 31, 2007
Asset Retirement Obligation, Beginning of Year	**$ 1,458**	$ 1,051
Liabilities Incurred	**26**	89
Liabilities Settled	**(80)**	(100)
Liabilities Divested	**(3)**	-
Change in Estimated Future Cash Flows	**(5)**	184
Accretion Expense	**41**	64
Other	**(35)**	170
Asset Retirement Obligation, End of Period	**$ 1,402**	$ 1,458

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. SHARE CAPITAL

(millions)	June 30, 2008 Number		June 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	**2.8**		**76**	8.3		176
Stock-Based Compensation	**-**		**11**	-		17
Common Shares Purchased	**(2.8)**		**(13)**	(36.0)		(301)
Common Shares Outstanding, End of Period	**750.2**	**$**	**4,553**	750.2	$	4,479

Normal Course Issuer Bid

To June 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 June 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)**	**23.66**
Outstanding, End of Period	**0.6**	**13.25**
Exercisable, End of Period	**0.6**	**13.25**

	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	1.4	11.62	0.5	11.62
22.00 to 25.99	0.1	0.3	24.62	0.1	24.62
	0.6	1.3	13.25	0.6	13.25

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"). The 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	
	June 30, 2008	December 31, 2007
Long-Term Debt, excluding current portion	**$ 9,878**	$ 8,840
Less: Working capital	**(2,086)**	(1,886)
Net Debt	**11,964**	10,726
Total Shareholders' Equity	**20,817**	20,704
Total Capitalization	**$ 32,781**	$ 31,430
Net Debt to Capitalization ratio	**36%**	34%

EnCana's Net Debt to Capitalization ratio increased to 36 percent from 34 percent at December 31, 2007 primarily due to unrealized mark-to-market losses on risk management instruments which increased Net Debt. Excluding this impact, the Net Debt to Capitalization ratio would have been 34 percent at June 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 June 30, 2008, the Net Debt to Adjusted EBITDA was 1.3x (December 31, 2007 - 1.2x) calculated on a trailing twelve-month basis as follows:

	As at	
	June 30, 2008	December 31, 2007
Net Debt	**$ 11,964**	$ 10,726
Net Earnings from Continuing Operations	**$ 3,255**	$ 3,884
Add (deduct):		
Interest, net	**514**	428
Income tax expense	**1,265**	937
Depreciation, depletion and amortization	**4,206**	3,816
Accretion of asset retirement obligation	**76**	64
Foreign exchange (gain) loss, net	**(99)**	(164)
(Gain) loss on divestitures	**(24)**	(65)
Adjusted EBITDA	**$ 9,193**	$ 8,900
Net Debt to Adjusted EBITDA	**1.3x**	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 June 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 June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Current Service Cost	**$ 4**	$ 4	**$ 8**	$ 8
Interest Cost	**6**	5	**11**	9
Expected Return on Plan Assets	**(5)**	(5)	**(10)**	(9)
Expected Actuarial Loss on Accrued Benefit Obligation	**1**	1	**2**	2
Expected Amortization of Past Service Costs	**-**	1	**1**	1
Amortization of Transitional Obligation	**-**	(1)	**(1)**	(1)
Expense for Defined Contribution Plan	**10**	9	**20**	16
Net Benefit Plan Expense	**$ 16**	$ 14	**$ 31**	$ 26

For the period ended June 30, 2008, contributions of $7 million have been made to the defined benefit pension plans (2007 - $4 million).

B) Tandem Share Appreciation Rights ("TSARs")

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

	Outstanding TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**18,854,141**	**48.44**
Granted	**3,998,422**	**70.26**
Exercised - SARs	**(2,845,548)**	**43.72**
Exercised - Options	**(46,810)**	**42.41**
Forfeited	**(288,175)**	**52.59**
Outstanding, End of Period	**19,672,030**	**53.51**
Exercisable, End of Period	**8,317,809**	**45.57**

For the period ended June 30, 2008, EnCana recorded compensation costs of $340 million related to the outstanding TSARs (2007 - $157 million).

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

The following table summarizes the information about Performance TSARs at June 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	**(259,466)**	**56.09**
Exercised - Options	**(3,669)**	**56.09**
Forfeited	**(454,914)**	**57.94**
Outstanding, End of Period	**13,271,414**	**63.11**
Exercisable, End of Period	**1,497,135**	**56.09**

For the period ended June 30, 2008, EnCana recorded compensation costs of $126 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 June 30, 2008:

	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	-	-
Granted	951,065	71.71
Forfeited	(17,250)	69.40
Outstanding, End of Period	933,815	71.75
Exercisable, End of Period	-	-

For the period ended June 30, 2008, EnCana recorded compensation costs of $5 million 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 June 30, 2008:

	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	-	-
Granted	1,677,030	69.40
Forfeited	(34,500)	69.40
Outstanding, End of Period	1,642,530	69.40
Exercisable, End of Period	-	-

For the period ended June 30, 2008, EnCana recorded compensation costs of $4 million 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 June 30, 2008:

	Outstanding DSUs	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**589,174**	**33.78**
Granted, Directors	**82,218**	**67.92**
Exercised	**(34,008)**	**91.00**
Units, in Lieu of Dividends	**6,208**	**85.17**
Outstanding, End of Period	**643,592**	**35.61**
Exercisable, End of Period	**643,592**	**35.61**

For the period ended June 30, 2008, EnCana recorded compensation costs of $23 million related to the outstanding DSUs (2007 - $11 million).

G) Performance Share Units ("PSUs")

The following table summarizes the information about PSUs at June 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 June 30, 2008, EnCana recorded compensation costs of $1 million related to the outstanding PSUs (2007 - $15 million).

16. PER SHARE AMOUNTS

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

	Three Months Ended			Six Months Ended	
	March 31,	June 30,		June 30,	
(millions)	2008	**2008**	2007	**2008**	2007
Weighted Average Common Shares Outstanding - Basic	749.5	**750.2**	758.5	**749.8**	763.5
Effect of Dilutive Securities	3.5	**1.1**	6.7	**2.5**	9.7
Weighted Average Common Shares Outstanding - Diluted	753.0	**751.3**	765.2	**752.3**	773.2

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 June 30, 2008		As at December 31, 2007	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Held-for-Trading:				
Cash and cash equivalents	**$ 778**	**$ 778**	$ 553	$ 553
Risk management assets *	**606**	**606**	403	403
Loans and Receivables:				
Accounts receivable and accrued revenues	**3,346**	**3,346**	2,381	2,381
Partnership contribution receivable *	**3,297**	**3,297**	3,444	3,444
Financial Liabilities				
Held-for-Trading:				
Risk management liabilities *	**$ 1,690**	**$ 1,690**	$ 236	$ 236
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**4,888**	**4,888**	3,982	3,982
Long-term debt *	**10,369**	**10,461**	9,543	9,763
Partnership contribution payable *	**3,309**	**3,309**	3,451	3,451

* Including current portion.

B) Risk Management Assets and Liabilities

Net Risk Management Position	**As at June 30, 2008**	As at December 31, 2007
Risk Management		
Current asset	**$ 265**	$ 385
Long-term asset	**341**	18
	606	403
Risk Management		
Current liability	**1,617**	207
Long-term liability	**73**	29
	1,690	236
Net Risk Management Asset (Liability)	**$ (1,084)**	$ 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 June 30, 2008			As at December 31, 2007		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Natural gas	$ 566	$ 1,381	$ (815)	$ 375	$ 29	$ 346
Crude oil	5	309	(304)	6	205	(199)
Power	35	-	35	19	-	19
Interest Rates	-	-	-	2	-	2
Credit	-	-	-	1	2	(1)
Total Fair Value	$ 606	$ 1,690	$ (1,084)	$ 403	$ 236	$ 167

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

	As at June 30, 2008	As at December 31, 2007
Prices actively quoted	$ (1,476)	$ 148
Prices sourced from observable data or market corroboration	392	19
Total Fair Value	$ (1,084)	$ 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 June 30, 2008

	Notional Volumes	Term	Average Price	Fair Market Value
Natural Gas Sales Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	1,494 MMcf/d	2008	8.20 US$/Mcf	$ (1,419)
NYMEX Fixed Price	391 MMcf/d	2009	9.85 US$/Mcf	(364)
Options				
Purchased AECO Call Options	(6) MMcf/d	2008	10.85 C$/Mcf	1
Purchased NYMEX Call Options	(851) MMcf/d	2008	11.55 US$/Mcf	223
Purchased NYMEX Put Options	136 MMcf/d	2008	8.85 US$/Mcf	(9)
Purchased NYMEX Put Options	341 MMcf/d	2009	8.85 US$/Mcf	(18)
Basis Contracts				
Canada	175 MMcf/d	2008	(0.76) US$/Mcf	27
United States	1,058 MMcf/d	2008	(1.66) US$/Mcf	240
Canada and United States *		2009-2011		377
				(942)
Other Financial Positions **				(33)
Total Unrealized Loss on Financial Contracts				(975)
Paid Premiums on Unexpired Options				160
Natural Gas Fair Value Position				$ (815)

* 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 June 30, 2008 (continued)

	Notional Volumes	Term	Average Price	Fair Market Value
Crude Oil Sales Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	23,000 bbls/d	2008	70.13 US$/bbl	$ (297)
Other Financial Positions **				(7)
Crude Oil Fair Value Position				$ (304)
Power Purchase Contracts				
Power Fair Value Position				$ 35

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

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

	Realized Gain (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Revenues, Net of Royalties	**$ (586)**	$ 382	**$ (566)**	$ 697
Operating Expenses and Other	**(2)**	-	**-**	1
Gain (Loss) on Risk Management	**$ (588)**	$ 382	**$ (566)**	$ 698

	Unrealized Gain (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	**2008**	2007
Revenues, Net of Royalties	**$ (328)**	$ 49	**$ (1,424)**	$ (566)
Operating Expenses and Other	**10**	6	**13**	7
Gain (Loss) on Risk Management	**$ (318)**	$ 55	**$ (1,411)**	$ (559)

Reconciliation of Unrealized Risk Management Positions from January 1 to June 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	**(1,977)**	**$ (1,977)**	$ 132
Fair Value of Contracts in Place at Transition that Expired During the Period	**-**	**-**	7
Fair Value of Contracts Realized During the Period	**566**	**566**	(698)
Fair Value of Contracts Outstanding	**$ (1,244)**	**$ (1,411)**	$ (559)
Paid Premiums on Unexpired Options	**160**		
Fair Value of Contracts and Premiums Paid, End of Period	**$ (1,084)**		

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 June 30, 2008 as follows:

	Favorable 10% Change	Unfavorable 10% Change
Natural gas price	$ 347	$ (303)
Crude oil price	60	(60)
Power price	4	(4)

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 derivative agreements. The use of 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 June 30, 2008, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $16 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 June 30, 2008, EnCana had $5,350 million in U.S. dollar debt issued from Canada ($5,421 million at December 31, 2007) and $3,297 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 $21 million change in foreign exchange (gain) loss at June 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 June 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 June 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 $7.2 billion. Of this unused shelf capacity, $2 billion expired on July 9, 2008. 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 proposed corporate reorganization (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	$ 4,888	$ -	$ -	$ -	$ 4,888
Risk management liabilities	1,617	73	-	-	1,690
Long-term debt *	491	450	3,314	6,136	10,391
Partnership contribution payable *	297	649	732	1,631	3,309

* Principal, including current portion.

Included in EnCana's total long-term debt obligations of $10,391 million at June 30, 2008 are $2,323 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.

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	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
TOTAL CONSOLIDATED									
Cash Flow [(1)]		**5,278**	**2,889**	2,389	8,453	1,934	2,218	2,549	1,752
Per share	- Basic	**7.04**	**3.85**	3.19	11.17	2.58	2.96	3.36	2.28
	- Diluted	**7.02**	**3.85**	3.17	11.06	2.56	2.93	3.33	2.25
Net Earnings		**1,314**	**1,221**	93	3,959	1,082	934	1,446	497
Per share	- Basic	**1.75**	**1.63**	0.12	5.23	1.44	1.24	1.91	0.65
	- Diluted	**1.75**	**1.63**	0.12	5.18	1.43	1.24	1.89	0.64
Operating Earnings [(2)]		**2,514**	**1,469**	1,045	4,100	849	1,032	1,369	850
Per share	- Diluted	**3.34**	**1.96**	1.39	5.36	1.12	1.37	1.79	1.09
CONTINUING OPERATIONS									
Cash Flow from Continuing Operations [(3)]		**5,278**	**2,889**	2,389	8,453	1,934	2,218	2,549	1,752
Net Earnings from Continuing Operations		**1,314**	**1,221**	93	3,884	1,007	934	1,446	497
Per share	- Basic	**1.75**	**1.63**	0.12	5.13	1.34	1.24	1.91	0.65
	- Diluted	**1.75**	**1.63**	0.12	5.08	1.33	1.24	1.89	0.64
Operating Earnings - Continuing Operations [(4)]		**2,514**	**1,469**	1,045	4,100	849	1,032	1,369	850
Effective Tax Rates using									
Net Earnings		**40.0%**			19.4%				
Operating Earnings, excluding divestitures		**31.5%**			28.6%				
Canadian Statutory Rate		**29.7%**			32.3%				
Foreign Exchange Rates *(US$ per C$1)*									
Average		**0.993**	**0.990**	0.996	0.930	1.019	0.957	0.911	0.854
Period end		**0.982**	**0.982**	0.973	1.012	1.012	1.004	0.940	0.867
CASH FLOW INFORMATION									
Cash from Operating Activities		**3,754**	**1,996**	1,758	8,429	2,193	2,180	2,148	1,908
Deduct (Add back):									
Net change in other assets and liabilities		**(264)**	**(171)**	(93)	(16)	(21)	1	(16)	20
Net change in non-cash working capital		**(1,260)**	**(722)**	(538)	(8)	280	(39)	(385)	136
Cash Flow [(1)]		**5,278**	**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	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*								
Period end	**750.2**	**750.2**	750.0	750.2	750.2	749.5	752.8	761.3
Average - Basic	**749.8**	**750.2**	749.5	756.8	749.8	750.4	758.5	768.4
Average - Diluted	**752.3**	**751.3**	753.0	764.6	755.1	755.9	765.2	779.6
Price Range *($ per share)*								
TSX - C$								
High	**97.81**	**97.81**	79.26	71.21	69.59	67.99	71.21	59.65
Low	**59.95**	**76.41**	59.95	51.55	60.89	59.33	57.61	51.55
Close	**93.36**	**93.36**	78.20	67.50	67.50	61.50	65.52	58.40
NYSE - US$								
High	**99.36**	**99.36**	79.75	75.85	75.85	65.18	66.87	51.49
Low	**58.13**	**74.16**	58.13	42.38	60.86	55.13	50.58	42.38
Close	**90.93**	**90.93**	75.75	67.96	67.96	61.85	61.45	50.63
Dividends Paid *($ per share)*	**0.80**	**0.40**	0.40	0.80	0.20	0.20	0.20	0.20
Share Volume Traded *(millions)*	**731.1**	**376.4**	354.7	1,250.9	290.8	301.4	327.4	331.3
Share Value Traded *(US$ millions weekly average)*	**2,194.1**	**2,486.0**	1,900.5	1,390.9	1,489.3	1,414.4	1,479.5	1,209.5

Financial Metrics		
Net Debt to Capitalization	**36%**	34%
Net Debt to Adjusted EBITDA *	**1.3x**	1.2x
Return on Capital Employed	**13%**	15%
Return on Common Equity	**17%**	21%

* Calculated on a trailing twelve-month basis.

Net Capital Investment *($ millions)*	**2008**	2007
Capital		
Canadian Plains	**$ 420**	$ 340
Canadian Foothills	**1,337**	1,052
United States	**1,179**	861
Integrated Oil	**529**	270
Offshore & International	**53**	62
Market Optimization	**7**	3
Corporate [(1)]	**42**	67
Capital	**3,567**	2,655
Acquisitions		
Property		
Canadian Foothills	**92**	7
United States	**244**	3
Integrated Oil	**-**	14
Divestitures		
Property		
Canadian Plains	**(31)**	-
Canadian Foothills	**(70)**	(12)
United States	**(95)**	(11)
Integrated Oil	**(8)**	-
Offshore & International [(2)]	**53**	(159)
Corporate [(3)]	**-**	(57)
Corporate		
Offshore & International [(4)]	**-**	(207)
Net Acquisition and Divestiture Activity	**185**	(422)
Net Capital Investment	**$ 3,752**	$ 2,233

(1) Includes capital expenditures on The Bow office project.
(2) Sale of Mackenzie Delta assets closed May 30, 2007.
(3) Sale of EnCana's office building project assets, The Bow, closed February 9, 2007.
(4) 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	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*								
Canadian Plains	**857**	**856**	860	875	876	858	874	891
Canadian Foothills	**1,273**	**1,289**	1,256	1,255	1,313	1,280	1,231	1,196
United States	**1,591**	**1,629**	1,552	1,345	1,464	1,387	1,303	1,222
Integrated Oil - Other	**66**	**67**	65	91	69	105	98	91
Total Produced Gas	**3,787**	**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	**31,116**	**30,479**	31,752	32,156	31,706	32,064	31,740	33,129
Canadian Foothills	**8,621**	**8,376**	8,867	8,216	8,441	7,978	7,959	8,489
Heavy Oil								
Canadian Plains	**36,323**	**34,618**	38,029	38,784	38,581	38,647	38,408	39,510
Foster Creek/Christina Lake	**27,024**	**24,671**	29,376	26,814	27,190	28,740	27,994	23,269
Integrated Oil - Other	**3,261**	**3,009**	3,514	2,688	3,040	2,235	2,489	2,990
Natural Gas Liquids [1]								
Canadian Plains	**1,226**	**1,189**	1,262	1,260	1,422	1,209	1,206	1,203
Canadian Foothills	**11,517**	**11,779**	11,256	10,056	10,966	9,932	9,811	9,497
United States	**13,358**	**13,482**	13,232	14,180	14,791	15,578	13,809	12,503
Total Oil and Natural Gas Liquids	**132,446**	**127,603**	137,288	134,154	136,137	136,383	133,416	130,590
Total *(MMcfe/d)*	**4,582**	**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
Crude oil runs *(Mbbls/d)*	**423**	**437**	408	432	439	460	396	433
Crude utilization *(%)*	**94%**	**97%**	90%	96%	97%	102%	88%	96%
Refined products *(Mbbls/d)*	**450**	**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	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas - Canadian Plains *($/Mcf)*								
Price	**8.34**	**9.50**	7.19	6.10	6.21	5.26	6.66	6.25
Production and mineral taxes	**0.12**	**0.17**	0.06	0.11	0.04	0.13	0.14	0.12
Transportation and selling	**0.24**	**0.22**	0.25	0.26	0.25	0.25	0.26	0.27
Operating	**0.94**	**0.96**	0.93	0.69	0.81	0.62	0.69	0.65
Netback	**7.04**	**8.15**	5.95	5.04	5.11	4.26	5.57	5.21
Produced Gas - Canadian Foothills *($/Mcf)*								
Price	**8.79**	**9.94**	7.61	6.30	6.44	5.46	6.86	6.46
Production and mineral taxes	**0.06**	**0.09**	0.03	0.08	0.04	0.08	0.11	0.10
Transportation and selling	**0.45**	**0.43**	0.47	0.42	0.41	0.41	0.43	0.43
Operating	**1.40**	**1.39**	1.41	1.05	1.14	0.96	1.02	1.09
Netback	**6.88**	**8.03**	5.70	4.75	4.85	4.01	5.30	4.84
Produced Gas - United States *($/Mcf)*								
Price	**9.08**	**9.93**	8.19	5.38	5.03	4.68	5.73	6.24
Production and mineral taxes	**0.67**	**0.72**	0.62	0.34	0.29	0.38	0.17	0.53
Transportation and selling	**0.81**	**0.81**	0.81	0.62	0.64	0.60	0.65	0.61
Operating	**0.71**	**0.71**	0.71	0.65	0.70	0.52	0.71	0.67
Netback	**6.89**	**7.69**	6.05	3.77	3.40	3.18	4.20	4.43
Produced Gas - Total *($/Mcf)*								
Price	**8.81**	**9.83**	7.75	5.89	5.83	5.10	6.38	6.32
Production and mineral taxes	**0.33**	**0.37**	0.28	0.18	0.14	0.21	0.14	0.26
Transportation and selling	**0.55**	**0.55**	0.56	0.45	0.46	0.44	0.47	0.45
Operating	**1.02**	**1.01**	1.02	0.82	0.90	0.72	0.83	0.82
Netback	**6.91**	**7.90**	5.89	4.44	4.33	3.73	4.94	4.79
Natural Gas Liquids - Canadian Plains *($/bbl)*								
Price	**85.40**	**96.34**	75.09	59.98	73.12	61.29	56.08	46.69
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**-**	**-**	-	-	-	-	-	-
Netback	**85.40**	**96.34**	75.09	59.98	73.12	61.29	56.08	46.69
Natural Gas Liquids - Canadian Foothills *($/bbl)*								
Price	**91.25**	**101.23**	80.80	59.26	73.42	63.06	55.10	42.82
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**1.39**	**1.73**	1.04	1.14	1.08	2.02	0.83	0.61
Netback	**89.86**	**99.50**	79.76	58.12	72.34	61.04	54.27	42.21
Natural Gas Liquids - United States *($/bbl)*								
Price	**94.14**	**105.73**	82.22	59.83	73.45	60.17	55.43	47.77
Production and mineral taxes	**8.46**	**9.75**	7.13	4.28	6.12	1.95	4.71	4.56
Transportation and selling	**-**	**-**	-	0.01	-	0.01	0.01	0.01
Netback	**85.68**	**95.98**	75.09	55.54	67.33	58.21	50.71	43.20
Natural Gas Liquids - Total *($/bbl)*								
Price	**92.44**	**103.29**	81.24	59.61	73.42	61.31	55.33	45.66
Production and mineral taxes	**4.29**	**4.94**	3.63	2.36	3.30	1.13	2.59	2.43
Transportation and selling	**0.62**	**0.78**	0.46	0.46	0.44	0.76	0.34	0.26
Netback	**87.53**	**97.57**	77.15	56.79	69.68	59.42	52.40	42.97
Crude Oil - Light and Medium - Canadian Plains *($/bbl)*								
Price	**96.25**	**107.08**	85.90	56.41	68.78	59.68	52.43	44.81
Production and mineral taxes	**3.33**	**3.97**	2.72	2.37	2.36	2.16	2.37	2.59
Transportation and selling	**1.22**	**1.27**	1.16	1.33	1.22	1.39	1.27	1.43
Operating	**12.31**	**13.05**	11.60	9.20	10.34	8.84	9.10	8.55
Netback	**79.39**	**88.79**	70.42	43.51	54.86	47.29	39.69	32.24
Crude Oil - Light and Medium - Canadian Foothills *($/bbl)*								
Price	**103.53**	**114.28**	93.42	64.63	81.51	67.07	57.00	52.31
Production and mineral taxes	**1.59**	**2.05**	1.16	1.05	1.59	0.76	1.47	0.37
Transportation and selling	**2.30**	**2.70**	1.92	1.77	1.66	2.16	1.79	1.49
Operating	**14.59**	**15.39**	13.84	10.84	12.72	11.21	9.31	10.03
Netback	**85.05**	**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	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil - Heavy - Canadian Plains *($/bbl)*								
Price	**83.96**	**98.65**	70.44	43.91	49.52	48.22	40.70	37.22
Production and mineral taxes	**(0.01)**	**(0.10)**	0.07	0.05	0.07	0.06	0.06	(0.01)
Transportation and selling	**1.44**	**1.60**	1.29	1.18	1.13	1.36	1.19	1.03
Operating	**10.59**	**11.30**	9.93	7.59	9.06	7.27	7.56	6.48
Netback	**71.94**	**85.85**	59.15	35.09	39.26	39.53	31.89	29.72
Crude Oil - Total - excluding Foster Creek/Christina Lake *($/bbl)*								
Price	**90.68**	**103.40**	78.82	50.76	59.93	54.68	47.02	41.42
Production and mineral taxes	**1.53**	**1.81**	1.28	1.09	1.12	1.01	1.16	1.06
Transportation and selling	**1.48**	**1.61**	1.36	1.32	1.23	1.47	1.31	1.27
Operating	**12.16**	**13.00**	11.39	9.03	10.52	8.68	8.85	8.06
Netback	**75.51**	**86.98**	64.79	39.32	47.06	43.52	35.70	31.03
Crude Oil - Heavy - Foster Creek/Christina Lake *($/bbl)*								
Price	**76.10**	**93.64**	59.67	40.14	45.58	42.86	39.40	33.28
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**2.74**	**2.77**	2.72	2.88	2.75	2.10	3.62	3.07
Operating [(1)]	**18.94**	**21.41**	16.62	14.46	14.05	12.55	14.02	17.12
Netback	**54.42**	**69.46**	40.33	22.80	28.78	28.21	21.76	13.09
Crude Oil - Total *($/bbl)*								
Price	**87.08**	**100.99**	74.10	47.90	56.23	51.50	44.92	39.19
Production and mineral taxes	**1.16**	**1.36**	0.96	0.79	0.83	0.74	0.84	0.77
Transportation and selling	**1.79**	**1.90**	1.69	1.74	1.62	1.64	1.94	1.75
Operating	**13.83**	**15.08**	12.68	10.49	11.43	9.72	10.27	10.54
Netback	**70.30**	**82.65**	58.77	34.88	42.35	39.40	31.87	26.13
Total Liquids - Canada *($/bbl)*								
Price	**87.46**	**100.97**	74.69	48.92	57.92	52.50	45.83	39.50
Production and mineral taxes	**1.03**	**1.20**	0.86	0.72	0.74	0.66	0.76	0.70
Transportation and selling	**1.74**	**1.86**	1.62	1.68	1.56	1.66	1.84	1.67
Operating	**12.29**	**13.34**	11.30	9.47	10.20	8.78	9.29	9.60
Netback	**72.40**	**84.57**	60.91	37.05	45.42	41.40	33.94	27.53
Total Liquids *($/bbl)*								
Price	**88.13**	**101.46**	75.44	50.05	59.60	53.37	46.81	40.25
Production and mineral taxes	**1.77**	**2.09**	1.46	1.08	1.32	0.81	1.16	1.04
Transportation and selling	**1.56**	**1.67**	1.46	1.51	1.39	1.47	1.65	1.51
Operating	**11.13**	**12.00**	10.30	8.57	9.19	7.87	8.41	8.81
Netback	**73.67**	**85.70**	62.22	38.89	47.70	43.22	35.59	28.89
Total *($/Mcfe)*								
Price	**9.82**	**11.02**	8.61	6.35	6.57	5.80	6.65	6.40
Production and mineral taxes	**0.32**	**0.37**	0.28	0.18	0.15	0.19	0.15	0.24
Transportation and selling	**0.50**	**0.50**	0.50	0.42	0.42	0.41	0.43	0.42
Operating [(2)]	**1.16**	**1.17**	1.15	0.93	1.02	0.83	0.93	0.95
Netback	**7.84**	**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 $0.15/Mcfe (2007 - $0.06/Mcfe).

Impact of Realized Financial Hedging

Natural Gas *($/Mcf)*	**(0.52)**	**(1.29)**	0.27	1.33	1.49	1.65	1.24	0.92
Liquids *($/bbl)*	**(8.36)**	**(10.99)**	(5.85)	(3.05)	(8.76)	(4.36)	(1.34)	2.34
Total *($/Mcfe)*	**(0.67)**	**(1.38)**	0.05	0.99	0.96	1.21	0.96	0.82

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