Q2 2009

ENCANA
energy for people

EnCana generates second quarter cash flow of US$2.2 billion, or $2.87 per share – down 25 percent

Natural gas hedges deliver $900 million of realized after-tax gains

Calgary, Alberta, (July 23, 2009) – EnCana Corporation (TSX & NYSE: ECA) continued to deliver strong financial and operating performance in the second quarter of 2009 – a period of very low natural gas prices. Cash flow was $2.2 billion, or $2.87 per share, and operating earnings were $917 million, or $1.22 per share – down 25 and 38 percent respectively on a per share basis compared to the second quarter of 2008. EnCana's financial performance was greatly enhanced by its commodity price hedges, which contributed a $900 million after-tax gain, or $1.20 per share, to cash flow in the second quarter. Second quarter natural gas and oil production remained flat at 4.6 billion cubic feet equivalent per day (Bcfe/d) compared to the second quarter of 2008.

"EnCana's continued strong financial and operating performance during this period of weak natural gas prices provides clear evidence of how our risk management measures reduce volatility in our business and help us continue to enhance long-term value creation. In the past year, natural gas prices dropped close to 70 percent, yet we have continued to meet or exceed our 2009 financial and operating objectives. Our natural gas price hedges provide an increased level of certainty to our cash flows so that we can most effectively manage our capital programs. Operationally, our production is on track for the year and we have additional natural gas productive capacity that we are not bringing on due to the prevailing weak prices. In our oil activities, we've seen a promising price recovery from the first quarter of 2009 and our newly expanded oil projects at Foster Creek and Christina Lake are ramping up production, up about 65 percent in the past year," said Randy Eresman, EnCana's President & Chief Executive Officer.

"Through 2009, EnCana will remain focused on directing our capital investment to our lowest cost, highest return projects and on maintaining our financial strength and flexibility. We are taking advantage of cost deflation and reduced industry activity by renegotiating supply and services contracts and by improving efficiencies. EnCana's cost reduction initiatives, announced in February, have already exceeded our savings target of $900 million for the year. Some of those savings, achieved primarily through capital reductions, have been redeployed to other parts of our portfolio, largely to shale gas plays," Eresman said.

"Our financial position remains strong. In the past few months, we have secured additional support for our financial future by hedging more than 45 percent of our expected natural gas production during the 2010 gas year at a price averaging $6.09 per thousand cubic feet (Mcf). During all periods in the economic cycle, we strive to be the leading North American resource play company developing unconventional natural gas and enhanced oil," Eresman said.

IMPORTANT NOTE: EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report gas and oil 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). Per share amounts for cash flow and earnings are on a diluted basis.

Second Quarter 2009 Highlights

(all year-over-year comparisons are to the second quarter of 2008)

Financial

- Cash flow decreased 25 percent per share to $2.87, or $2.2 billion
- Operating earnings were down 38 percent per share to $1.22, or $917 million
- Net earnings decreased 80 percent to 32 cents per share, or $239 million
- Capital investment, excluding acquisitions and divestitures, was down 37 percent to $1.1 billion, primarily due to lower drilling and completion costs as a result of fewer wells drilled, cost deflation, a weaker Canadian dollar and lower long-term incentive costs as a result of a decline in share price
- Free cash flow was $1.1 billion, down 8 percent (Free cash flow is defined in Note 1 on page 8)
- EnCana's integrated oil business venture with ConocoPhillips generated $293 million in operating cash flow, comprised of $139 million from the company's Foster Creek and Christina Lake upstream projects, and $154 million from the downstream business. Operating cash flow was down $174 million largely due to lower crack spreads and capacity utilization in the downstream business
- Realized natural gas prices were down 18 percent to $6.99 per Mcf and realized liquids prices decreased 44 percent to $50.23 per barrel (bbl). These prices include financial hedges
- At the end of the quarter, debt to capitalization was 27 percent and debt to adjusted EBITDA was 0.7 times
- Paid dividend of 40 cents per share
- Completed public offering in the United States of notes totalling $500 million at 6.5 percent

Operating – Upstream

- Key resource play production was up 1 percent, with a 27 percent increase in oil production and a 1 percent decrease in natural gas production
- Total natural gas production decreased 1 percent to 3.79 billion cubic feet per day (Bcf/d), down 1 percent per share
- Total oil and natural gas liquids (NGLs) production increased 6 percent to almost 136,000 barrels per day (bbls/d), up 6 percent per share
- Foster Creek and Christina Lake oil production grew 65 percent to approximately 40,700 bbls/d net to EnCana
- Operating and administrative costs of $1.15 per thousand cubic feet equivalent (Mcfe) decreased from $1.71 per Mcfe in the second quarter of 2008, primarily due to lower long-term incentive costs as a result of a decline in share price, a weaker Canadian dollar, and lower repairs, maintenance and workover costs

Operating – Downstream

- Refined products averaged 428,000 bbls/d (214,000 bbls/d net to EnCana), down 8 percent
- Refinery crude utilization of 89 percent or 404,000 bbls/d crude throughput (202,000 bbls/d net to EnCana), down 8 percent.

Net earnings positively impacted by hedging program

EnCana's net earnings were impacted by mark-to-market accounting for hedging contracts. EnCana's second quarter net earnings of $239 million were down $982 million from the second quarter of 2008. Net earnings in the second quarter of 2009 included a $900 million after-tax, realized gain on hedging, primarily offset by a $750 million after-tax, unrealized loss that was previously included in net earnings as unrealized gains due to mark-to-market accounting. It is because of these dramatic mark-to-market accounting swings in net earnings that EnCana focuses on operating earnings as a better measure of quarter-over-quarter earnings performance.

Realized after-tax hedging gains for the first eight months of the 2008-2009 natural gas year, which runs from November 1, 2008 to October 31, 2009, were $1.9 billion and, as of June 30, 2009, unrealized after-tax gains for the remainder of the gas year were about $1.1 billion, for a total of approximately $3.0 billion, after tax.

Financial Summary – Total Consolidated

(for the period ended June 30) ($ millions, except per share amounts)	**Q2 2009**	Q2 2008	% Δ	**6 months 2009**	6 months 2008	% Δ
Cash flow[1]	**2,153**	2,889	-25	**4,097**	5,278	-22
Per share diluted	**2.87**	3.85	-25	**5.45**	7.02	-22
Operating earnings[1]	**917**	1,469	-38	**1,865**	2,514	-26
Per share diluted	**1.22**	1.96	-38	**2.48**	3.34	-26
Net earnings	**239**	1,221	-80	**1,201**	1,314	-9
Per share diluted	**0.32**	1.63	-80	**1.60**	1.75	-9

Earnings Reconciliation Summary – Total Consolidated

	Q2 2009	Q2 2008	% Δ	6 months 2009	6 months 2008	% Δ
Net earnings	**239**	1,221		**1,201**	1,314	
Add back (losses) & deduct gains						
Unrealized mark-to-market gain (loss), after tax	**(750)**	(235)		**(661)**	(972)	
Non-operating foreign exchange gain (loss), after tax	**72**	(13)		**(3)**	(228)	
Operating earnings[1]	**917**	1,469	-38	**1,865**	2,514	-26
Per share diluted	**1.22**	1.96	-38	**2.48**	3.34	-26

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

Production & Drilling Summary

Total Consolidated

(for the period ended June 30) (After royalties)	**Q2 2009**	Q2 2008	% Δ	**6 months 2009**	6 months 2008	% Δ
Natural Gas (MMcf/d)	**3,788**	3,841	-1	**3,828**	3,787	+1
Natural gas production per 1,000 shares (Mcf/d)	**5.04**	5.12	-1	**5.10**	5.05	+1
Oil and NGLs (Mbbls/d)	**136**	128	+6	**135**	132	+2
Oil and NGLs production per 1,000 shares (Mcfe/d)	**1.09**	1.02	+6	**1.08**	1.06	+2
Total Production (MMcfe/d)	**4,602**	4,607	-	**4,638**	4,582	+1
Total production per 1,000 shares (Mcfe/d)	**6.13**	6.14	-	**6.18**	6.11	+1
Net wells drilled	**216**	409	-47	**1,099**	1,552	-29

Key resource play oil production grows 27 percent; key resource play natural gas production steady
Oil and natural gas production from key resource plays increased 1 percent to 3.56 Bcfe/d compared to 3.51 Bcfe/d in the second quarter of 2008. Oil production was up 27 percent from the second quarter of 2008 to about 75,000 bbls/d led by Foster Creek and Christina Lake. Natural gas resource play production was down slightly, by 1 percent, to 3.1 Bcf/d, with lower volumes offset by Cutbank Ridge, which saw strong performance from the company's Montney developments in British Columbia. Production volumes benefited from lower royalties in Alberta, which were offset by a decision, due to lower prices and netbacks in certain areas, to shut in some wells, restrict some wells' productive capacity and delay some well completions or tie-ins to sales pipelines. These company-wide initiatives resulted in between 300 million and 400 million cubic feet per day (MMcf/d) being kept off line.

Integrated oil business contributes solid second quarter performance
EnCana's integrated oil business continued its strong performance with Foster Creek and Christina Lake production increasing 65 percent to about 40,700 bbls/d compared to the same quarter in 2008. Year-over-year oil prices fell dramatically from the record highs seen one year ago, but prices recovered significantly, up close to 40 percent, from the low levels experienced in the first quarter of 2009. Operating cash flow for Foster Creek and Christina Lake was up 11 percent to $139 million in 2009 compared to $125 million in 2008. The downstream operations reported a 55 percent decrease in operating cash flow to $154 million from $342 million mainly due to lower crack spreads and capacity utilization.

Expansion of enhanced oil production capacity at Foster Creek and Christina Lake remains on track
At Foster Creek, phases D and E were commissioned in the second quarter, each adding 30,000 bbls/d of productive capacity. Production continues to ramp up and is on target to exit 2009 exceeding 90,000 bbls/d (45,000 bbls/d net to EnCana). In the second quarter, a regulatory application was initiated for Foster Creek's phases F, G, and H with each phase expected to add about 30,000 bbls/d of productive capacity. At Christina Lake, construction of phase C continues to proceed on schedule and on budget. Phase C is expected to add about 40,000 bbls/d of capacity, with first production forecast in late 2011. Phase D of the Christina Lake project is targeted to be sanctioned by EnCana and ConocoPhillips in the fourth quarter of 2009. Regulatory applications for phases E, F and G at Christina Lake are expected to be filed in the third quarter of 2009 with each of these new phases designed to add approximately 40,000 bbls/d of productive capacity. EnCana continues to proceed through the regulatory application process for future expansion phases at Foster Creek and Christina Lake although exact timing of construction and initial production from these phases is subject to receipt of regulatory approvals and partnership sanction.

Haynesville and Horn River shale plays continue to show very strong results
EnCana continues to see improved operational performance and strong initial production rates from its Haynesville shale gas play. To date, EnCana has drilled 25 gross horizontal wells in the play. EnCana has increased fracture stimulations in each horizontal well from eight to as many as 14. This efficiency initiative has helped increase initial production rates and reduce well costs by about 35 percent from prior wells to an estimated $9 million per well. The strongest well performance continues to be in the northern portion of the company's Red River Parish leases where EnCana has a joint venture with Shell. EnCana exited the second quarter with gross production from North Louisiana of about 100 MMcf/d. EnCana is currently operating 10 rigs in the Haynesville Shale, up from five at the start of 2009, and is participating in another four rigs operated by Shell.

At Horn River, the joint drilling program by EnCana and Apache Corporation at Two Island Lake continues to meet or exceed expectations for both initial well production and expected size of the resource. As a result of the joint venture's combined activities, to date 32 gross wells have been drilled to evaluate the basin and 10 gross horizontal wells placed on production. Similar to activity at the Haynesville, fracture stimulations at Horn River have increased to up to 14 stages per horizontal section. The first wells completed in 2009 were placed on production towards the end of the quarter. The wells have shown strong results with flow rates of 9.5 MMcf/d to 11 MMcf/d after 15 days of initial flow. EnCana also commissioned a new compression and dehydration facility as well as a gas gathering pipeline that connects the Two Island Lake area with the Spectra pipeline system near the proposed EnCana operated Cabin gas plant.

Large opportunity ahead for abundant, affordable, cleaner-burning natural gas
"Looking ahead, we strongly believe there are tremendous opportunities for expanding the use of clean-burning natural gas to help solve some of our continent's most pressing energy, environmental and economic challenges. A number of respected geological authorities have recently confirmed the abundant nature of North American natural gas. This abundance will help ensure an affordable future for expanding natural gas in our economy, primarily by displacing foreign oil in transportation and by fuelling electricity generation. While the use of natural gas as a convenient and economic transportation fuel for trucks and cars is not common in North America, it is in wide use on other continents. As a step in that direction, EnCana has started to convert a portion of its vehicle fleet to run on natural gas in select Canadian and U.S. operating locations," Eresman said.

Growth from key North American resource plays

Resource Play (After royalties)	Daily Production								
	2009			2008					2007
	YTD	**Q2**	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas (MMcf/d)									
Jonah	**600**	**576**	623	603	573	615	630	595	557
Piceance	**371**	**355**	386	385	377	407	383	372	348
East Texas	**356**	**304**	409	334	408	339	316	273	143
Fort Worth	**144**	**138**	149	142	143	148	137	140	124
Greater Sierra	**215**	**216**	215	220	228	228	219	205	211
Cutbank Ridge	**332**	**340**	323	296	311	322	280	271	258
Bighorn	**171**	**186**	156	167	165	185	170	146	126
CBM	**319**	**330**	309	304	308	309	303	298	259
Shallow Gas	**667**	**661**	673	700	683	691	712	715	726
Total natural gas (MMcf/d)	**3,175**	**3,106**	3,243	3,151	3,196	3,244	3,150	3,015	2,752
Oil (Mbbls/d)									
Foster Creek	**31**	**34**	28	26	29	27	21	27	24
Christina Lake	**6**	**6**	7	4	6	5	4	2	3
Pelican Lake	**20**	**19**	21	22	20	22	21	24	23
Weyburn	**16**	**15**	16	14	15	14	13	14	15
Total oil (Mbbls/d)[1]	**74**	**75**	72	66	71	67	59	67	65
Total (MMcfe/d)[1]	**3,617**	**3,557**	3,676	3,548	3,621	3,648	3,506	3,417	3,141
% change from prior period	**+4.6**	**-3.2**	+1.5	+13.0	-0.7	+4.1	+2.6	+2.7	+12.9

1 Totals may not add due to rounding.

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled								
	2009			2008					2007
	YTD	**Q2**	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas									
Jonah	**65**	**30**	35	175	40	43	49	43	135
Piceance	**88**	**35**	53	328	70	94	81	83	286
East Texas	**26**	**11**	15	78	23	22	22	11	35
Fort Worth	**22**	**6**	16	83	21	21	20	21	75
Greater Sierra	**25**	**10**	15	106	14	29	27	36	109
Cutbank Ridge	**38**	**18**	20	82	17	17	24	24	93
Bighorn	**35**	**14**	21	64	5	11	18	30	62
CBM	**279**	**1**	278	698	359	78	10	251	1,079
Shallow Gas	**381**	**45**	336	1,195	383	233	83	496	1,914
Total gas wells	**959**	**170**	789	2,809	932	548	334	995	3,788
Oil									
Foster Creek	**16**	**10**	6	20	1	6	1	12	23
Christina Lake	**-**	**-**	-	-	-	-	-	-	3
Pelican Lake	**5**	**1**	4	-	-	-	-	-	-
Weyburn	**-**	**-**	-	21	3	4	5	9	37
Total oil wells	**21**	**11**	10	41	4	10	6	21	63
Total	**980**	**181**	799	2,850	936	558	340	1,016	3,851

Second quarter natural gas and oil prices						
	Q2 2009	Q2 2008	% Δ	**6 months 2009**	6 months 2008	% Δ
Natural gas ($/MMBtu)						
NYMEX	**3.50**	10.93	-68	**4.19**	**9.48**	-56
EnCana realized gas price[1] ($/Mcf)	**6.99**	8.54	-18	**7.11**	**8.29**	-14
Oil and NGLs ($/bbl)						
WTI	**59.79**	123.80	-52	**51.68**	**111.12**	-53
Western Canadian Select (WCS)	**52.37**	102.18	-49	**43.50**	**89.58**	-51
Differential WTI/WCS	**7.42**	21.62	-66	**8.18**	**21.54**	-62
EnCana realized liquids price [1]	**50.23**	90.47	-44	**42.45**	**79.77**	-47
Chicago 3-2-1 crack spread ($/bbl)	**10.95**	13.60	-19	**10.35**	**10.65**	-3

1 Realized prices include the impact of financial hedging.

Price risk management

Risk management positions at June 30, 2009 are presented in Note 16 to the unaudited Interim Consolidated Financial Statements. In the second quarter of 2009, EnCana's commodity price risk management measures resulted in realized gains of approximately $900 million after tax, composed of an $896 million after-tax gain on gas prices and basis hedges and a $4 million after-tax gain on other hedges.

EnCana has hedged two-thirds of expected 2009 natural gas production, about 2.6 Bcf/d, through October of this year at an average NYMEX equivalent price of $9.13 per Mcf. EnCana has also extended its risk management program through 2010. As of July 21, 2009, EnCana had established fixed price hedges on more than 45 percent of the company's expected 2010 natural gas production - or about 2 Bcf/d - at an average NYMEX equivalent price of $6.09 per Mcf for the gas year, which runs from November 1, 2009 to October 31, 2010. EnCana also has 20,000 bbls/d of expected 2010 oil production hedged at an average fixed price of WTI $76.45 per bbl. This price hedging strategy increases certainty in cash flow to help ensure that EnCana can meet its capital and dividend requirements without substantially adding to debt. EnCana continually assesses its hedging needs and the opportunities available prior to establishing its capital program for the upcoming year.

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, 2009 to common shareholders of record as of September 15, 2009. Based on the July 22, 2009 closing share price on the New York Stock Exchange of $52.57, this represents an annualized yield of about 3 percent.

"Plans for splitting EnCana into two independent companies, creating an integrated oil company and a pure-play natural gas company, continue to be evaluated, but are currently on hold as market conditions continue to be volatile," Eresman said.

Guidance updated

EnCana has updated its 2009 guidance for total natural gas, oil and NGLs production to a range of 4.4 to 4.8 Bcfe/d from 4.5 to 4.7 Bcfe/d. EnCana has also updated its capital investment guidance from $6.1 billion to a range of $5.5 billion to $6 billion. Total operating cost guidance has been reduced to $1.00 from $1.10 per Mcfe. Updated guidance and key resource play information is posted on the company's website at www.encana.com.

EnCana sells non-core properties for $632 million

On July 16, 2009, EnCana announced it had reached an agreement to sell approximately 409,000 net acres of non-core natural gas and oil producing properties for approximately $632 million to Bonavista Energy Trust. Current production on these lands is approximately 60 MMcfe/d, after royalties. The transaction includes properties known as the Hoadley trend which covers an expansive area in west-central Alberta. The sale has an effective date of April 1, 2009 and is subject to typical closing conditions and regulatory approvals. It is expected to close in the third quarter of 2009.

Financial strength

EnCana has a very strong balance sheet, with 88 percent of EnCana's outstanding debt comprised of long-term, fixed-rate debt with an average remaining term of more than 13 years. Upcoming debt maturities in 2009 are $250 million and in 2010 are $200 million. At June 30, 2009, EnCana had $3.4 billion in unused committed credit facilities. EnCana manages its financial strategy to achieve a strong investment grade credit rating. EnCana targets a debt to capitalization ratio of less than 40 percent and a debt to adjusted EBITDA ratio of less than 2.0 times. At June 30, 2009, the company's debt to capitalization ratio was 27 percent and debt to adjusted EBITDA, on a trailing 12-month basis, was 0.7 times.

On May 4, 2009, EnCana completed a public offering in the United States of $500 million notes with an interest rate of 6.50 percent due on May 15, 2019. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness. The offering was made in the United States under EnCana's previously filed shelf prospectus dated March 11, 2008 and a prospectus supplement dated April 29, 2009.

In the quarter, EnCana invested $1.1 billion in capital on continued development of the company's long-term production and refining assets – including the coker and refinery expansion (CORE) project at the Wood River refinery in Illinois, expansion of upstream oil projects in northeast Alberta, development of the Deep Panuke natural gas project offshore Nova Scotia, and other long-term upstream projects with substantial future growth potential.

NOTE 1: Non-GAAP measures
This interim report contains references to non-GAAP measures as follows:

- 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, in this interim report and interim financial statements.
- 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.
- 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 the U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- Capitalization is a non-GAAP measure defined as debt plus shareholders' equity. Debt to capitalization and debt to adjusted EBITDA are two ratios which 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 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 $50 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: future economic and operating performance (including per share growth, debt to capitalization ratio, debt to adjusted EBITDA ratio, sustainable growth and returns, free cash flow, cash flow, cash flow per share, operating earnings and increases in net asset value); projections contained in the company's guidance forecasts and the anticipated ability to meet the company's guidance forecasts; anticipated life of proved reserves; anticipated growth and success of resource plays and the expected characteristics of resource plays; anticipated production and drilling in the Horn River and Haynesville areas; anticipated cost reductions and production efficiencies from fracture stimulations; anticipated capacity and timing for the proposed Cabin Gas Plant; planned expansion of in-situ oil production; anticipated crude oil and natural gas prices, including basis differentials for various regions; anticipated expansion and production at Foster Creek and Christina Lake; anticipated divestitures; potential dividends; anticipated success of EnCana's price risk management strategy; anticipated hedging gains; potential demand for natural gas; anticipated drilling; potential capital expenditures and investment; potential oil, natural gas and NGLs production in 2009 and beyond; anticipated plans to ramp up production in the event of the recovery of natural gas prices; anticipated conversion of natural gas powered vehicles; anticipated costs and cost reductions; the company's plans for splitting into two independent companies and the conditions which may be required therefore; the expected closing date for the Bonavista Energy Trust transaction; and references to potential exploration. 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 assumptions, 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 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, greenhouse gas, carbon, accounting 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 2009 cash flow for EnCana is based upon achieving average production of oil and gas for 2009 of approximately 4.4 to 4.8 Bcfe/d, year-to-date actuals and forward curve estimates for commodity prices and US/Canadian dollar foreign exchange rate as of June 30, 2009 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 interim report.

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, 2009, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2008. 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 22, 2009.

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 Advisory section located at the end of this document.

EnCana's Financial Strategy in the Current Economic Environment

Although economic conditions have improved slightly from the start of 2009, the current economic environment continues to be challenging and uncertain amidst a global recession, low commodity prices and volatile financial markets. In this economic environment, EnCana is highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, further optimizing capital investments and continuing to pay a stable dividend to shareholders. This measured investment approach is underpinned by a strong balance sheet and a market risk mitigation strategy where EnCana has hedged about two thirds of its expected gas production through October 2009 at an average NYMEX equivalent price of $9.13 per Mcf and, as of June 30, 2009, approximately 1.7 billion cubic feet per day ("Bcf/d") of gas fixed price contracts from November 2009 to October 2010 at an average NYMEX equivalent price of $6.16 per Mcf. Additional actions within EnCana's risk management program are more fully described in the Risk Management section of this MD&A. During the first six months of 2009, EnCana has benefited from its commodity price hedging program, which has resulted in realized hedging gains of $1.6 billion after-tax.

EnCana has a strong balance sheet and continues to employ a conservative capital structure. As at June 30, 2009, 88 percent of EnCana's outstanding debt was composed of long-term, fixed rate debt with an average remaining term of more than 13 years. Upcoming maturities are $250 million in 2009 and $200 million in 2010. As at June 30, 2009, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.2 billion and unused committed bank credit facilities in the amount of $3.4 billion. EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times. At June 30, 2009, the Company's Debt to Capitalization ratio was 27 percent and Debt to Adjusted EBITDA was 0.7 times.

In addition, EnCana continues to monitor expenses and capital programs. In light of the current market situation, EnCana has planned a measured, flexible approach to 2009 investment and has designed a 2009 capital program with the flexibility to adjust investment depending upon how economic circumstances unfold during the year. Additional detail regarding EnCana's 2009 capital investment is available in the Corporate Guidance on the Company's website at www.encana.com.

EnCana's Business

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

EnCana's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and natural gas liquids ("NGLs") and other related activities within the Canadian cost centre.
- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.

- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include 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 and Other** mainly 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 sells substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. Segmented financial information is presented on an after eliminations basis.

EnCana has a decentralized decision making and reporting structure. Accordingly, the Company is organized into divisions as follows:

- **Canadian Plains** Division includes natural gas and crude oil exploration, development and production assets located in eastern Alberta and Saskatchewan.
- **Canadian Foothills** Division includes natural gas exploration, development and production assets located in western Alberta and British Columbia as well as the Company's Canadian offshore assets.
- **USA** Division includes natural gas exploration, development and production assets located in the United States and comprises the USA segment described above.
- **Integrated Oil** Division is the combined total of Integrated Oil – Canada and Downstream Refining. Integrated Oil – Canada includes the Company's exploration for, and development and production of bitumen using enhanced recovery methods. Integrated Oil – Canada is composed of EnCana's interests in the FCCL Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.

2009 versus 2008 Results Review

In the second quarter of 2009 compared to the second quarter of 2008, EnCana:

- Reported a 25 percent decrease in Cash Flow to $2,153 million primarily due to lower commodity prices partially offset by realized hedging gains of $900 million after-tax and lower expenses;
- Reported a 38 percent decrease in Operating Earnings to $917 million;
- Reported an 80 percent decrease in Net Earnings to $239 million primarily due to lower commodity prices. Net Earnings in the quarter included realized hedging gains of $900 million after-tax that were mostly offset by the reversal of accrued after-tax unrealized mark-to-market hedging gains recognized in prior periods netted against additional after-tax unrealized hedging gains resulting primarily from new contracts entered into during the quarter;
- Reported Free Cash Flow of $1,075 million compared to $1,171 million in 2008;
- Reported total production of 4,602 million cubic feet equivalent ("MMcfe") per day ("MMcfe/d"), which remained relatively unchanged;
- Reported decreased production from natural gas key resource plays of 1 percent and increased production from oil key resource plays of 27 percent;
- Reported a 68 percent decrease in average natural gas prices, excluding financial hedges, to $3.12 per thousand cubic feet ("Mcf") and a 52 percent decrease in average liquids prices, excluding financial hedges, to $49.14 per barrel ("bbl"); and
- Subsequent to the second quarter, EnCana reached an agreement to sell certain non-core natural gas and oil producing properties in Alberta for approximately $632 million.

In the six months of 2009 compared to the six months of 2008, EnCana:

- Reported a 22 percent decrease in Cash Flow to $4,097 million primarily due to lower commodity prices partially offset by realized hedging gains of $1,599 million after-tax and lower expenses;
- Reported a 26 percent decrease in Operating Earnings to $1,865 million;
- Reported a 9 percent decrease in Net Earnings to $1,201 million primarily due to lower commodity prices. Net Earnings for the six months of 2009 included realized hedging gains of $1,599 million after-tax offset by the reversal of accrued after-tax unrealized mark-to-market hedging gains recognized in prior periods netted against

additional after-tax unrealized hedging gains resulting primarily from new contracts entered into during the second quarter;

- Reported Free Cash Flow of $1,511 million compared to $1,711 million in 2008;
- Reported a 1 percent increase in total production to 4,638 MMcfe/d;
- Reported increased production from natural gas key resource plays of 3 percent and from oil key resource plays of 16 percent;
- Reported a 58 percent decrease in average natural gas prices, excluding financial hedges, to $3.68 per Mcf and a 54 percent decrease in average liquids prices, excluding financial hedges, to $40.81 per bbl; and
- Subsequent to the second quarter, EnCana reached an agreement to sell certain non-core natural gas and oil producing properties in Alberta for approximately $632 million.

Business Environment

EnCana's financial results are significantly influenced by fluctuations in commodity prices, which include price differentials and crack spreads, and the U.S./Canadian dollar exchange rate. EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found in the December 31, 2008 Management's Discussion and Analysis and Note 16 to the Interim Consolidated Financial Statements. The following table shows benchmark information on a quarterly basis to assist in understanding quarterly volatility in prices and foreign exchange rates that have impacted EnCana's financial results.

Quarterly Market Benchmark Prices and Foreign Exchange Rates

	Six Months Ended June 30		2009		2008				2007	
(Average for the period)	**2009**	2008	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Natural Gas Price Benchmarks										
AECO *(C$/Mcf)*	**$ 4.65**	$ 8.24	**$ 3.66**	$ 5.63	$ 6.79	$ 9.24	$ 9.35	$ 7.13	$ 6.00	$ 5.61
NYMEX *($/MMBtu)*	**4.19**	9.48	**3.50**	4.89	6.94	10.24	10.93	8.03	6.97	6.16
Rockies (Opal) *($/MMBtu)*	**2.84**	7.79	**2.37**	3.31	3.53	5.88	8.56	7.02	3.46	2.94
Texas (HSC) *($/MMBtu)*	**3.82**	9.16	**3.44**	4.21	6.37	9.98	10.58	7.73	6.64	5.89
Basis Differential *($/MMBtu)*										
AECO/NYMEX	**0.37**	1.28	**0.39**	0.35	1.10	1.28	1.71	0.84	0.85	0.84
Rockies/NYMEX	**1.35**	1.69	**1.13**	1.58	3.41	4.36	2.37	1.01	3.50	3.22
Texas/NYMEX	**0.37**	0.32	**0.06**	0.68	0.58	0.26	0.35	0.30	0.33	0.27
Crude Oil Price Benchmarks										
West Texas Intermediate (WTI) *($/bbl)*	**51.68**	111.12	**59.79**	43.31	59.08	118.22	123.80	97.82	90.50	75.15
Western Canadian Select (WCS) *($/bbl)*	**43.50**	89.58	**52.37**	34.38	39.95	100.22	102.18	76.37	56.85	52.71
Differential - WTI/WCS *($/bbl)*	**8.18**	21.54	**7.42**	8.93	19.13	18.00	21.62	21.45	33.65	22.44
Refining Margin Benchmark										
Chicago 3-2-1 Crack Spread *($/bbl)* (1)	**10.35**	10.65	**10.95**	9.75	6.31	17.29	13.60	7.69	9.17	18.48
Foreign Exchange										
U.S./Canadian Dollar Exchange Rate	**0.829**	0.993	**0.857**	0.803	0.825	0.961	0.990	0.996	1.019	0.957

(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 Ultra Low Sulphur Diesel.

Consolidated Financial Results

($ millions, except per share amounts)	Six Months Ended June 30 2009	Six Months Ended June 30 2008	2009 Q2	2009 Q1	2008 Q4	2008 Q3	2008 Q2	2008 Q1	2007 Q4	2007 Q3
Total Consolidated										
Cash Flow (1)	**$ 4,097**	$ 5,278	**$ 2,153**	$ 1,944	$ 1,299	$ 2,809	$ 2,889	$ 2,389	$ 1,934	$ 2,218
- per share – diluted	**5.45**	7.02	**2.87**	2.59	1.73	3.74	3.85	3.17	2.56	2.93
Net Earnings	**1,201**	1,314	**239**	962	1,077	3,553	1,221	93	1,082	934
- per share – basic	**1.60**	1.75	**0.32**	1.28	1.44	4.74	1.63	0.12	1.44	1.24
- per share – diluted	**1.60**	1.75	**0.32**	1.28	1.43	4.73	1.63	0.12	1.43	1.24
Operating Earnings (2)	**1,865**	2,514	**917**	948	449	1,442	1,469	1,045	849	1,032
- per share – diluted	**2.48**	3.34	**1.22**	1.26	0.60	1.92	1.96	1.39	1.12	1.37
Cash Dividends – per share	**0.80**	0.80	**0.40**	0.40	0.40	0.40	0.40	0.40	0.20	0.20
Revenues, Net of Royalties	**8,370**	12,856	**3,762**	4,608	6,359	10,849	7,422	5,434	5,875	5,654

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

Despite the continued low commodity price environment during the six months of 2009, EnCana generated strong financial results. EnCana's upstream operations continued to benefit from its commodity price hedging program. Further discussion of EnCana's financial results can be found in the Results of Operations 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 and net change in non-cash working capital from continuing operations. While Cash Flow is considered a non-GAAP measure, it is 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

($ millions)	Three Months Ended June 30 2009	Three Months Ended June 30 2008	Six Months Ended June 30 2009	Six Months Ended June 30 2008
Cash From Operating Activities	**$ 1,955**	$ 1,996	**$ 3,786**	$ 3,754
(Add back) deduct:				
Net change in other assets and liabilities	**9**	(171)	**23**	(264)
Net change in non-cash working capital	**(207)**	(722)	**(334)**	(1,260)
Cash Flow	**$ 2,153**	$ 2,889	**$ 4,097**	$ 5,278

Three Months Ended June 30, 2009 versus 2008

Cash Flow in 2009 decreased $736 million or 25 percent compared to 2008 as a result of:

- Average total natural gas prices, excluding financial hedges, decreased 68 percent to $3.12 per Mcf in 2009 compared to $9.83 per Mcf in 2008;
- Average total liquids prices, excluding financial hedges, decreased 52 percent to $49.14 per bbl in 2009 compared to $101.46 per bbl in 2008; and
- Natural gas production volumes in 2009 decreased 1 percent to 3,788 million cubic feet ("MMcf") per day ("MMcf/d") from 3,841 MMcf/d in 2008;
- Operating Cash Flow from Downstream operations decreased $188 million to $154 million in 2009;

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $900 million after-tax in 2009 compared to losses of $400 million after-tax in 2008;

- Liquids production volumes in 2009 increased 6 percent to 135,653 barrels per day ("bbls/d") from 127,603 bbls/d in 2008; and
- Decreases in operating, production and mineral taxes, transportation and selling, administrative and interest expenses in 2009 compared to 2008.

Six Months Ended June 30, 2009 versus 2008

Cash Flow in 2009 decreased $1,181 million or 22 percent compared to 2008 as a result of:

- Average total natural gas prices, excluding financial hedges, decreased 58 percent to $3.68 per Mcf in 2009 compared to $8.81 per Mcf in 2008; and
- Average total liquids prices, excluding financial hedges, decreased 54 percent to $40.81 per bbl in 2009 compared to $88.13 per bbl in 2008;
- Operating Cash Flow from Downstream operations decreased $222 million to $213 million in 2009;

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $1,599 million after-tax in 2009 compared to losses of $387 million after-tax in 2008;
- Natural gas production volumes in 2009 increased 1 percent to 3,828 MMcf/d from 3,787 MMcf/d in 2008; and
- Decreases in operating, transportation and selling, administrative, production and mineral taxes and interest expenses in 2009 compared to 2008.

Net Earnings

Three Months Ended June 30, 2009 versus 2008

Net Earnings in 2009 of $239 million were $982 million lower compared to 2008. Items affecting Cash Flow detailed previously, also affect Net Earnings. Items affecting Net Earnings were:

- Realized hedging gains of $900 million after-tax in 2009 compared to realized hedging losses of $400 million after-tax in 2008 detailed previously in the change to Cash Flow were mostly offset by the reversal of accrued after-tax unrealized mark-to-market hedging gains recognized in prior periods netted against additional after-tax unrealized hedging gains resulting primarily from new contracts entered into during the quarter;

partially offset by:

- DD&A decreased $117 million in 2009 compared to 2008 primarily due to lower DD&A rates as a result of higher proved reserves and the lower U.S./Canadian dollar exchange rate;
- Long-term compensation costs decreased $112 million in 2009 compared to 2008 due to the change in the EnCana share price and the lower U.S./Canadian dollar exchange rate; and
- Non-operating foreign exchange gains of $72 million after-tax in 2009 compared to losses of $13 million after-tax in 2008.

Six Months Ended June 30, 2009 versus 2008

Net Earnings in 2009 of $1,201 million were $113 million lower compared to 2008. Items affecting Cash Flow detailed previously, also affect Net Earnings. Items affecting Net Earnings were:

- Realized hedging gains of $1,599 million after-tax in 2009 compared to realized hedging losses of $387 million after-tax in 2008 detailed previously in the change to Cash Flow were partially offset by the reversal of accrued after-tax unrealized mark-to-market hedging gains recognized in prior periods netted against additional after-tax unrealized hedging gains resulting primarily from new contracts entered into during the second quarter;
- Long-term compensation costs decreased $255 million in 2009 compared to 2008 due to the change in the EnCana share price and the lower U.S./Canadian dollar exchange rate;
- Non-operating foreign exchange losses of $3 million after-tax in 2009 compared to losses of $228 million after-tax in 2008; and
- DD&A decreased $169 million in 2009 compared to 2008 primarily due to lower DD&A rates as a result of higher proved reserves and the lower U.S./Canadian dollar exchange rate.

Operating Earnings

Operating Earnings is a non-GAAP measure that adjusts Net Earnings by non-operating items that Management believes reduces 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.

Summary of Operating Earnings

	Three Months Ended June 30				Six Months Ended June 30			
	2009		2008		2009		2008	
($ millions, except per share amounts)		Per share[4]		Per share[4]		Per share[4]		Per share[4]
Net Earnings, as reported	**$ 239**	**$ 0.32**	$ 1,221	$ 1.63	**$ 1,201**	**$ 1.60**	$ 1,314	$ 1.75
Add back (losses) and deduct gains:								
Unrealized mark-to-market hedging gain (loss), after-tax [1]	**(750)**	**(1.00)**	(235)	(0.31)	**(661)**	**(0.88)**	(972)	(1.29)
Non-operating foreign exchange gain (loss), after-tax [2]	**72**	**0.10**	(13)	(0.02)	**(3)**	**-**	(228)	(0.30)
Operating Earnings [3]	**$ 917**	**$ 1.22**	$ 1,469	$ 1.96	**$ 1,865**	**$ 2.48**	$ 2,514	$ 3.34

(1) Unrealized mark-to-market hedging gains (losses), after-tax are offset by realized gains (losses), after-tax in Net Earnings. In the 2009 second quarter results, the unrealized mark-to-market hedging gains (losses), after-tax primarily represents the reversal of gains (losses) recognized in prior periods. The realized gains (losses), after-tax primarily represents the recording of the final resulting settlement of hedge positions.
(2) Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt and 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.
(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 hedging 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. The Company's calculation of Operating Earnings excludes foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.
(4) 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 decreased 13 percent to $0.857 in the second quarter of 2009 compared to $0.990 in the second quarter of 2008 and decreased 17 percent to $0.829 in the six months of 2009 compared to $0.993 in the six months of 2008. The table below summarizes the impacts of these changes on EnCana's operations when compared to the same periods in the prior year.

	Three Months Ended June 30, 2009		Six Months Ended June 30, 2009	
Average U.S./Canadian Dollar Exchange Rate	**$ 0.857**		**$ 0.829**	
Change from comparative period in prior year	**(0.133)**		**(0.164)**	
($ millions, except $/Mcfe amounts)	**$ millions**	**$/Mcfe**	**$ millions**	**$/Mcfe**
Increase (decrease) in:				
Capital Investment	**$ (73)**		**$ (257)**	
Upstream Operating Expense	**(43)**	**(0.10)**	**(110)**	**(0.13)**
Other Operating Expense [1]	**(1)**		**(5)**	
Administrative Expense	**(12)**	**(0.03)**	**(26)**	**(0.03)**
DD&A Expense	**(86)**		**(210)**	

(1) Expenses related to Market Optimization and Corporate and Other.

Results of Operations

Production Volumes

	Six Months Ended June 30		2009		2008				2007	
	2009	2008	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Produced Gas *(MMcf/d)*	**3,828**	3,787	**3,788**	3,869	3,858	3,917	3,841	3,733	3,722	3,630
Crude Oil *(bbls/d)*	**112,477**	106,345	**112,968**	111,981	110,628	106,826	101,153	111,538	108,958	109,664
NGLs *(bbls/d)*	**22,492**	26,101	**22,685**	22,299	25,222	26,730	26,450	25,750	27,179	26,719
Total *(MMcfe/d)* (1)	**4,638**	4,582	**4,602**	4,675	4,673	4,718	4,607	4,557	4,539	4,448

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

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)	
	2009	**2009 vs 2008**	2008	**2009**	2008	**2009**	**2009 vs 2008**	2008	**2009**	2008
Natural Gas *(MMcf/d)*										
Jonah	**576**	**-9%**	630	**30**	49	**600**	**-2%**	613	**65**	92
Piceance	**355**	**-7%**	383	**35**	81	**371**	**-2%**	377	**88**	164
East Texas	**304**	**-4%**	316	**11**	22	**356**	**21%**	294	**26**	33
Fort Worth	**138**	**1%**	137	**6**	20	**144**	**4%**	138	**22**	41
Greater Sierra	**216**	**-1%**	219	**10**	27	**215**	**2%**	211	**25**	63
Cutbank Ridge	**340**	**21%**	280	**18**	24	**332**	**21%**	275	**38**	48
Bighorn	**186**	**9%**	170	**14**	18	**171**	**8%**	158	**35**	48
CBM	**330**	**9%**	303	**1**	10	**319**	**6%**	300	**279**	261
Shallow Gas	**661**	**-7%**	712	**45**	83	**667**	**-6%**	713	**381**	579
	3,106	**-1%**	3,150	**170**	334	**3,175**	**3%**	3,079	**959**	1,329
Oil *(bbls/d)*										
Foster Creek	**34,249**	**63%**	21,038	**10**	1	**31,227**	**31%**	23,904	**16**	13
Christina Lake	**6,428**	**77%**	3,633	**-**	-	**6,493**	**108%**	3,120	**-**	-
	40,677	**65%**	24,671	**10**	1	**37,720**	**40%**	27,024	**16**	13
Pelican Lake	**19,225**	**-10%**	21,434	**1**	-	**20,247**	**-11%**	22,669	**5**	-
Weyburn	**15,238**	**16%**	13,180	**-**	5	**15,665**	**15%**	13,580	**-**	14
	75,140	**27%**	59,285	**11**	6	**73,632**	**16%**	63,273	**21**	27
Total *(MMcfe/d)*	**3,557**	**1%**	3,506	**181**	340	**3,617**	**5%**	3,459	**980**	1,356

Total production volumes were relatively unchanged in the second quarter of 2009 compared to the second quarter of 2008 primarily due to increased production from EnCana's key resource plays of 1 percent, mainly attributable to a 65 percent increase in production volumes at Foster Creek/Christina Lake, and lower royalties offset by natural declines in conventional properties as well as shut-in and curtailed production and delayed well completions and tie-ins due to the low price environment. Total production volumes increased 1 percent or 56 MMcfe/d in the six months of 2009 compared to the six months of 2008 primarily due to increased production from EnCana's key resource plays of 5 percent, mainly attributable to a 40 percent increase in production volumes at Foster Creek/Christina Lake, and lower royalties offset by natural declines in conventional properties as well as shut-in and curtailed production and delayed well completions and tie-ins due to the low price environment.

Operating Netback Information

	Three Months Ended June 30					
	2009			2008		
	Gas ($/Mcf)	**Liquids ($/bbl)**	**Total ($/Mcfe)**	Gas ($/Mcf)	Liquids ($/bbl)	Total ($/Mcfe)
Price	**$ 3.12**	**$ 49.14**	**$ 4.02**	$ 9.83	$ 101.46	$ 11.02
Expenses						
Production and mineral taxes	**0.06**	**0.88**	**0.08**	0.37	2.09	0.37
Transportation and selling	**0.50**	**1.55**	**0.46**	0.55	1.67	0.50
Operating	**0.75**	**8.38**	**0.86**	1.01	12.00	1.17
Netback excluding Realized Financial Hedging	**1.81**	**38.33**	**2.62**	7.90	85.70	8.98
Realized Financial Hedging Gain (Loss)	**3.87**	**1.09**	**3.21**	(1.29)	(10.99)	(1.38)
Netback including Realized Financial Hedging	**$ 5.68**	**$ 39.42**	**$ 5.83**	$ 6.61	$ 74.71	$ 7.60

	Six Months Ended June 30					
	2009			2008		
	Gas ($/Mcf)	**Liquids ($/bbl)**	**Total ($/Mcfe)**	Gas ($/Mcf)	Liquids ($/bbl)	Total ($/Mcfe)
Price	**$ 3.68**	**$ 40.81**	**$ 4.22**	$ 8.81	$ 88.13	$ 9.82
Expenses						
Production and mineral taxes	**0.10**	**0.90**	**0.11**	0.33	1.77	0.32
Transportation and selling	**0.49**	**1.46**	**0.45**	0.55	1.56	0.50
Operating	**0.75**	**8.42**	**0.86**	1.02	11.13	1.16
Netback excluding Realized Financial Hedging	**2.34**	**30.03**	**2.80**	6.91	73.67	7.84
Realized Financial Hedging Gain (Loss)	**3.43**	**1.64**	**2.88**	(0.52)	(8.36)	(0.67)
Netback including Realized Financial Hedging	**$ 5.77**	**$ 31.67**	**$ 5.68**	$ 6.39	$ 65.31	$ 7.17

Netbacks, excluding financial hedges, decreased significantly during the second quarter and six months of 2009 compared to 2008 primarily due to lower commodity prices partially offset by lower expenses, the impact of the lower U.S./Canadian dollar exchange rate and lower long-term compensation costs due to the change in the EnCana share price.

As part of ongoing efforts to maintain financial resilience and flexibility, EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found in the December 31, 2008 Management's Discussion and Analysis and Note 16 to the Interim Consolidated Financial Statements. As evidenced in the table above, EnCana has benefited significantly from its hedging program during this period of weaker commodity prices.

Net Capital Investment

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2009**	2008	**2009**	2008
Canada				
Canadian Plains	**$ 69**	$ 158	**$ 228**	$ 420
Canadian Foothills	**280**	583	**745**	1,363
Integrated Oil – Canada	**103**	144	**229**	352
USA	**385**	660	**925**	1,179
Downstream Refining	**227**	122	**429**	177
Market Optimization	**-**	5	**(3)**	7
Corporate & Other	**14**	46	**33**	69
Capital Investment	**1,078**	1,718	**2,586**	3,567
Acquisitions	**34**	278	**113**	336
Divestitures	**(20)**	(79)	**(53)**	(151)
Net Capital Investment	**$ 1,092**	$ 1,917	**$ 2,646**	$ 3,752

EnCana's capital investment for the six months ended June 30, 2009 was funded by Cash Flow.

Capital investment during the six months of 2009 was primarily focused on continued development of EnCana's North American key resource plays and expansion of the Company's downstream heavy oil refining capacity through its joint venture with ConocoPhillips. Reported capital investment was lower due to changes in the average U.S./Canadian dollar exchange rate as well as the EnCana share price in determining long-term compensation costs. The net impact of these factors on capital investment was a decrease of $456 million in the six months of 2009 compared to the same period in 2008. Further information regarding the Company's capital investment can be found in the Divisional Results section of this MD&A.

Acquisitions and Divestitures

On May 5, 2009, the Company acquired the common shares of Kerogen Resources Canada, ULC for net cash consideration of $24 million. The acquisition included $37 million of property, plant and equipment and the assumption of $6 million of current liabilities and $7 million of future income taxes. The operations are included in the Canadian Foothills Division. The Company also had some minor property acquisitions and divestitures in the six months of 2009 and 2008.

Subsequent to the second quarter, on July 16, 2009, EnCana reached an agreement to sell certain non-core natural gas and oil producing properties in Alberta for approximately $632 million.

Free Cash Flow

EnCana's second quarter 2009 Free Cash Flow of $1,075 million and six months 2009 Free Cash Flow of $1,511 million were lower compared to the same periods in 2008. Reasons for the decrease in total Cash Flow and capital investment are discussed under the Cash Flow and Net Capital Investment sections of this MD&A.

($ millions)	Three Months Ended June 30 2009	Three Months Ended June 30 2008	Six Months Ended June 30 2009	Six Months Ended June 30 2008
Cash Flow [1]	**$ 2,153**	$ 2,889	**$ 4,097**	$ 5,278
Capital Investment	**1,078**	1,718	**2,586**	3,567
Free Cash Flow [2]	**$ 1,075**	$ 1,171	**$ 1,511**	$ 1,711

(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 activities, dividends and/or other financing activities.

Divisional Results

As discussed in EnCana's Business section of this MD&A, the Company has a decentralized decision making and reporting structure and is organized into divisions. Accordingly, results are presented at the divisional level. Canadian Plains Division and Canadian Foothills Division are included in the Canada segment. USA Division comprises the USA segment. Integrated Oil Division is the combined total of Integrated Oil – Canada and Downstream Refining.

Canadian Plains

Financial Results

Three Months Ended June 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	**$ 233**	**$ 341**	**$ 4**	**$ 578**	$ 739	$ 714	$ 2	$ 1,455
Realized Financial Hedging Gain (Loss)	**242**	**-**	**-**	**242**	(110)	(70)	-	(180)
Expenses								
Production and mineral taxes	**5**	**6**	**-**	**11**	13	11	-	24
Transportation and selling	**10**	**43**	**-**	**53**	18	97	-	115
Operating	**51**	**55**	**2**	**108**	74	72	1	147
Operating Cash Flow	**$ 409**	**$ 237**	**$ 2**	**$ 648**	$ 524	$ 464	$ 1	$ 989

Six Months Ended June 30, 2009 versus 2008

	2009				2008			
($ millions)	Gas	Oil & NGLs	Other	Total	Gas	Oil & NGLs	Other	Total
Revenues, Net of Royalties and Hedging	$ 551	$ 590	$ 6	$ 1,147	$ 1,302	$ 1,299	$ 4	$ 2,605
Realized Financial Hedging Gain (Loss)	445	3	-	448	(83)	(106)	-	(189)
Expenses								
Production and mineral taxes	8	13	-	21	18	19	-	37
Transportation and selling	21	94	-	115	37	187	-	224
Operating	102	106	3	211	147	140	2	289
Operating Cash Flow	$ 865	$ 380	$ 3	$ 1,248	$ 1,017	$ 847	$ 2	$ 1,866

Production Volumes

	Six Months Ended June 30		2009		2008				2007	
	2009	2008	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Produced Gas *(MMcf/d)*	796	857	792	800	820	831	856	860	876	858
Crude Oil *(bbls/d)*	64,855	67,439	62,691	67,043	64,990	64,789	65,097	69,781	70,287	70,711
NGLs *(bbls/d)*	1,181	1,226	1,162	1,201	1,126	1,147	1,189	1,262	1,422	1,209
Total *(MMcfe/d)* (1)	1,192	1,269	1,175	1,209	1,217	1,227	1,253	1,286	1,306	1,290

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

Produced Gas

Three Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $154 million in the second quarter of 2009 compared to the same period in 2008 due to:

- A $451 million impact resulting from a 66 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $55 million impact resulting from a 7 percent decrease in natural gas production volumes. Produced gas volumes decreased in the second quarter of 2009 due to expected natural declines for the Shallow Gas key resource play and conventional properties partially offset by lower royalties;

offset by:

- Realized financial hedging gains of $242 million or $3.36 per Mcf in 2009 compared to losses of $110 million or $1.42 per Mcf in 2008.

The decrease in Canadian Plains natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Canadian Plains natural gas transportation and selling costs of $10 million in 2009 decreased $8 million or 44 percent compared to 2008 due to lower volumes and costs to eastern Canada and the U.S. as well as the lower U.S./Canadian dollar exchange rate.

Canadian Plains natural gas operating expenses of $51 million in 2009 were $23 million or 31 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price, lower repairs and maintenance and workover costs partially offset by higher property tax and lease costs and increased salaries and benefits.

Six Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $223 million in the six months of 2009 compared to the same period in 2008 due to:

- A $652 million impact resulting from a 54 percent decrease in natural gas prices, excluding the impact of financial hedging; and

- A $99 million impact resulting from a 7 percent decrease in natural gas production volumes. Produced gas volumes decreased in the six months of 2009 due to expected natural declines for the Shallow Gas key resource play and conventional properties as well as the impact of wellhead freeze-offs and other temporary production shut-ins resulting from extreme winter weather in southern Alberta during the first quarter partially offset by lower royalties;

offset by:

- Realized financial hedging gains of $445 million or $3.09 per Mcf in 2009 compared to losses of $83 million or $0.53 per Mcf in 2008.

The decrease in Canadian Plains natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Canadian Plains natural gas transportation and selling costs of $21 million in 2009 decreased $16 million or 43 percent compared to 2008 due to lower volumes and costs to eastern Canada and the U.S. as well as the lower U.S./Canadian dollar exchange rate.

Canadian Plains natural gas operating expenses of $102 million in 2009 were $45 million or 31 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price, lower repairs and maintenance and workover costs partially offset by higher property tax and lease costs and increased salaries and benefits.

Crude Oil and NGLs

Three Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $303 million in the second quarter of 2009 compared to the same period in 2008 due to:

- A $302 million impact resulting from a 50 percent decrease in crude oil prices and 60 percent decrease in NGLs prices, excluding financial hedges;
- A $53 million impact resulting from a decrease in average prices and volume of condensate used for blending with heavy oil; and
- An $18 million impact resulting from a 4 percent decrease in crude oil volumes and 2 percent decrease in NGLs volumes. Production in 2009 from the Pelican Lake key resource play of 19,225 bbls/d was down 10 percent mainly due to a scheduled facility turnaround and Suffield production of 12,254 bbls/d was down 7 percent primarily due to natural declines. These were partially offset by lower royalties and a 16 percent increase in production at Weyburn, which averaged 15,238 bbls/d in 2009, mainly due to well optimizations;

offset by:

- Realized financial hedging gains on liquids were less than $1 million in 2009 compared to losses of $70 million or $11.43 per bbl in 2008.

Canadian Plains crude oil prices decreased 50 percent to $51.55 per bbl in 2009 from $102.55 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices offset by lower average differentials. Total realized financial hedging gains on crude oil for Canadian Plains were less than $1 million in 2009 compared to losses of approximately $69 million or $11.44 per bbl in 2008.

Canadian Plains NGLs prices decreased 60 percent to $38.36 per bbl in 2009 from $96.34 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Plains crude oil transportation and selling costs of $43 million in 2009 decreased $54 million or 56 percent compared to 2008 primarily due to a decrease in average prices and volume of condensate used for blending with heavy oil and the lower U.S./Canadian dollar exchange rate.

Canadian Plains crude oil operating costs of $55 million in 2009 were $17 million or 24 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price and reduced workover costs. 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.

Six Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $600 million in the six months of 2009 compared to the same period in 2008 due to:

- A $555 million impact resulting from a 52 percent decrease in crude oil prices and 57 percent decrease in NGLs prices, excluding financial hedges;
- A $90 million impact resulting from a decrease in average prices and volume of condensate used for blending with heavy oil; and
- A $64 million impact resulting from a 4 percent decrease in crude oil volumes and 4 percent decrease in NGLs volumes. Production in 2009 from the Pelican Lake key resource play of 20,247 bbls/d was down 11 percent mainly due to natural declines and a scheduled facility turnaround and Suffield production of 12,974 bbls/d was down 5 percent primarily due to natural declines. These were partially offset by lower royalties and a 15 percent increase in production at Weyburn, which averaged 15,665 bbls/d in 2009, mainly due to well optimizations;

offset by:

- Realized financial hedging gains on liquids of $3 million or $0.22 per bbl in 2009 compared to losses of $106 million or $8.43 per bbl in 2008.

Canadian Plains crude oil prices decreased 52 percent to $42.92 per bbl in 2009 from $89.58 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices offset by lower average differentials. Total realized financial hedging gains on crude oil for Canadian Plains were approximately $3 million or $0.22 per bbl in 2009 compared to losses of approximately $105 million or $8.45 per bbl in 2008.

Canadian Plains NGLs prices decreased 57 percent to $36.59 per bbl in 2009 from $85.40 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Plains crude oil transportation and selling costs of $94 million in 2009 decreased $93 million or 50 percent compared to 2008 primarily due to a decrease in average prices and volume of condensate used for blending with heavy oil and the lower U.S./Canadian dollar exchange rate.

Canadian Plains crude oil operating costs of $106 million in 2009 were $34 million or 24 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price and reduced workover costs partially offset by higher repairs and maintenance costs. 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.

Capital Investment

Canadian Plains capital investment of $228 million during the six months of 2009 was primarily focused on the Shallow Gas, Pelican Lake and Weyburn key resource plays. The $192 million decrease compared to 2008 was primarily due to lower drilling, completion and facility costs resulting from fewer wells drilled and tied in, the lower U.S./Canadian dollar exchange rate and lower capitalized long-term compensation costs. Canadian Plains drilled 430 net wells in the six months of 2009 compared to 680 net wells in 2008, consistent with the planned reduction in spending in 2009.

Canadian Foothills

Canadian Foothills Division includes the Company's Canadian offshore assets.

Financial Results

Three Months Ended June 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	$ 389	$ 74	$ 10	$ 473	$ 1,167	$ 195	$ 15	$ 1,377
Realized Financial Hedging Gain (Loss)	434	-	-	434	(167)	(21)	-	(188)
Expenses								
Production and mineral taxes	5	1	-	6	11	1	-	12
Transportation and selling	37	1	-	38	51	3	-	54
Operating	124	6	3	133	163	12	5	180
Operating Cash Flow	$ 657	$ 66	$ 7	$ 730	$ 775	$ 158	$ 10	$ 943

Six Months Ended June 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	$ 917	$ 131	$ 20	$ 1,068	$ 2,037	$ 353	$ 33	$ 2,423
Realized Financial Hedging Gain (Loss)	754	-	-	754	(128)	(31)	-	(159)
Expenses								
Production and mineral taxes	9	2	-	11	14	2	-	16
Transportation and selling	71	4	-	75	104	6	-	110
Operating	244	12	7	263	324	23	11	358
Operating Cash Flow	$ 1,347	$ 113	$ 13	$ 1,473	$ 1,467	$ 291	$ 22	$ 1,780

Production Volumes

	Six Months Ended June 30		2009		2008				2007	
	2009	2008	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Produced Gas *(MMcf/d)*	1,312	1,273	1,343	1,281	1,302	1,351	1,289	1,256	1,313	1,280
Crude Oil *(bbls/d)*	7,969	8,621	7,800	8,140	8,437	8,217	8,376	8,867	8,441	7,978
NGLs *(bbls/d)*	9,626	11,517	9,824	9,427	11,265	11,730	11,779	11,256	10,966	9,932
Total *(MMcfe/d)* (1)	1,418	1,394	1,449	1,386	1,420	1,471	1,410	1,377	1,429	1,387

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

Produced Gas

Three Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $177 million in the second quarter of 2009 compared to the same period in 2008 due to:

- An $823 million impact resulting from a 68 percent decrease in natural gas prices, excluding the impact of financial hedging;

offset by:

- Realized financial hedging gains of $434 million or $3.55 per Mcf in 2009 compared to losses of $167 million or $1.42 per Mcf in 2008; and
- A $49 million impact resulting from a 4 percent increase in natural gas production volumes. Produced gas volumes increased in the second quarter of 2009 as a result of lower royalties and drilling success in the key resource plays

of Cutbank Ridge and CBM partially offset by delayed well completions and tie-ins due to the low price environment, natural declines at Greater Sierra and conventional properties and the volume impact of minor property divestitures in 2008.

The decrease in Canadian Foothills natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Canadian Foothills natural gas transportation and selling costs of $37 million in 2009 decreased $14 million or 27 percent compared to 2008 due to the lower U.S./Canadian dollar exchange rate and lower volumes transported to the U.S.

Canadian Foothills natural gas operating expenses of $124 million in 2009 were $39 million or 24 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price, reduced repairs and maintenance and workover costs offset by higher salaries and benefits and property tax and lease costs.

Six Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $238 million in the six months of 2009 compared to the same period in 2008 due to:

- A $1,171 million impact resulting from a 56 percent decrease in natural gas prices, excluding the impact of financial hedging;

offset by:

- Realized financial hedging gains of $754 million or $3.17 per Mcf in 2009 compared to losses of $128 million or $0.55 per Mcf in 2008; and
- A $51 million impact resulting from a 3 percent increase in natural gas production volumes. Produced gas volumes increased in the six months of 2009 as a result of the impact of lower royalties and drilling success in the key resource plays of Cutbank Ridge and CBM partially offset by delayed well completions and tie-ins due to the low price environment, natural declines at conventional properties and the volume impact of minor property divestitures in 2008.

The decrease in Canadian Foothills natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Canadian Foothills natural gas transportation and selling costs of $71 million in 2009 decreased $33 million or 32 percent compared to 2008 due to the lower U.S./Canadian dollar exchange rate and lower volumes transported to the U.S.

Canadian Foothills natural gas operating expenses of $244 million in 2009 were $80 million or 25 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price, reduced repairs and maintenance and workover costs offset by higher salaries and benefits and property tax and lease costs.

Crude Oil and NGLs

Three Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $100 million in the second quarter of 2009 compared to the same period in 2008 due to:

- A $97 million impact resulting from a 54 percent decrease in crude oil prices and 60 percent decrease in NGLs prices, excluding financial hedges; and
- A $24 million impact resulting from a 7 percent decrease in crude oil volumes and 17 percent decrease in NGLs volumes. The decreases were due to natural declines and the volume impact of property divestitures;

offset by:

- Realized financial hedging losses on liquids were $21 million or $11.19 per bbl in 2008, with no comparable amount in 2009.

Canadian Foothills crude oil prices decreased 54 percent to $53.10 per bbl in 2009 from $114.28 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices offset by 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, with no comparable amount in 2009.

Canadian Foothills NGLs prices decreased 60 percent to $40.07 per bbl in 2009 from $101.23 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Foothills crude oil operating costs of $6 million in 2009 were $6 million or 50 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate and lower chemical costs. 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.

Six Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $191 million in the six months of 2009 compared to the same period in 2008 due to:

- A $176 million impact resulting from a 56 percent decrease in crude oil prices and 58 percent decrease in NGLs prices, excluding financial hedges; and
- A $46 million impact resulting from an 8 percent decrease in crude oil volumes and 16 percent decrease in NGLs volumes. The decreases were due to natural declines and the volume impact of property divestitures;

offset by:

- Realized financial hedging losses on liquids were less than $1 million in 2009 compared to losses of $31 million or $8.45 per bbl in 2008.

Canadian Foothills crude oil prices decreased 56 percent to $45.13 per bbl in 2009 from $103.53 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices offset by lower average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were less than $1 million in 2009 compared to losses of approximately $13 million or $8.17 per bbl in 2008.

Canadian Foothills NGLs prices decreased 58 percent to $38.00 per bbl in 2009 from $91.25 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Foothills crude oil operating costs of $12 million in 2009 were $11 million or 48 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate and lower gathering and processing costs. 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.

Capital Investment

Canadian Foothills capital investment of $745 million during the six months of 2009 was primarily focused on the CBM, Cutbank Ridge, Greater Sierra and Bighorn key resource plays. The $618 million decrease compared to 2008 was primarily due to lower drilling and facility costs, the lower U.S./Canadian dollar exchange rate and lower capitalized long-term compensation costs. Canadian Foothills drilled 385 net wells in the six months of 2009 compared to 473 net wells in 2008.

USA

Financial Results

Three Months Ended June 30, 2009 versus 2008

	2009				2008			
($ millions)	**Gas**	**Oil & NGLs**	**Other**	**Total**	Gas	Oil & NGLs	Other	Total
Revenues, Net of Royalties and Hedging	**$ 433**	**$ 50**	**$ 32**	**$ 515**	$ 1,472	$ 130	$ 87	$ 1,689
Realized Financial Hedging Gain (Loss)	**611**	**-**	**-**	**611**	(164)	-	-	(164)
Expenses								
Production and mineral taxes	**11**	**4**	**-**	**15**	107	11	-	118
Transportation and selling	**125**	**-**	**-**	**125**	120	-	-	120
Operating	**77**	**-**	**22**	**99**	106	-	80	186
Operating Cash Flow	**$ 831**	**$ 46**	**$ 10**	**$ 887**	$ 975	$ 119	$ 7	$ 1,101

Six Months Ended June 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	$ 1,043	$ 79	$ 59	$ 1,181	$ 2,630	$ 229	$ 159	$ 3,018
Realized Financial Hedging Gain (Loss)	1,119	-	-	1,119	(139)	-	-	(139)
Expenses								
Production and mineral taxes	54	7	-	61	194	20	-	214
Transportation and selling	248	-	-	248	235	-	-	235
Operating	159	-	55	214	207	-	148	355
Operating Cash Flow	$ 1,701	$ 72	$ 4	$ 1,777	$ 1,855	$ 209	$ 11	$ 2,075

Production Volumes

	Six Months Ended June 30		2009		2008				2007	
	2009	2008	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Produced Gas *(MMcf/d)*	1,663	1,591	1,581	1,746	1,677	1,674	1,629	1,552	1,464	1,387
NGLs *(bbls/d)*	11,685	13,358	11,699	11,671	12,831	13,853	13,482	13,232	14,791	15,578
Total *(MMcfe/d)* (1)	1,733	1,671	1,651	1,816	1,754	1,757	1,710	1,631	1,553	1,480

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

Produced Gas

Three Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $264 million in the second quarter of 2009 compared to the same period in 2008 due to:

- A $996 million impact resulting from a 70 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $43 million impact resulting from a 3 percent decrease in natural gas production volumes. Produced gas volumes in the USA decreased in the second quarter of 2009 primarily as a result of shut-in and curtailed production as well as delayed well completions due to the low price environment partially offset by drilling and operational success;

offset by:

- Realized financial hedging gains of $611 million or $4.25 per Mcf in 2009 compared to losses of $164 million or $1.11 per Mcf in 2008.

The decrease in USA natural gas prices in 2009, excluding the impact of financial hedges, reflects the changes in NYMEX, Rockies (Opal) and Texas (HSC) benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas production and mineral taxes for the USA of $11 million in 2009 decreased $96 million or 90 percent compared to 2008 primarily as a result of lower natural gas prices and high cost well tax credits.

Natural gas transportation and selling costs for the USA of $125 million in 2009 increased $5 million or 4 percent compared to 2008 primarily due to additional gathering and processing costs in East Texas.

Natural gas operating expenses for the USA of $77 million in 2009 were $29 million or 27 percent lower compared to 2008 as a result of lower long-term compensation costs due to the change in the EnCana share price, less activity resulting in lower workover costs, repairs and maintenance and reduced labour costs.

Six Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $329 million in the six months of 2009 compared to the same period in 2008 due to:

- A $1,691 million impact resulting from a 62 percent decrease in natural gas prices, excluding the impact of financial hedging;

offset by:

- Realized financial hedging gains of $1,119 million or $3.72 per Mcf in 2009 compared to losses of $139 million or $0.48 per Mcf in 2008; and
- A $104 million impact resulting from a 5 percent increase in natural gas production volumes. Produced gas volumes in the USA increased in the six months of 2009 as a result of drilling and operational success in East Texas and Haynesville partially offset by shut-in and curtailed production as well as delayed well completions due to the low price environment.

The decrease in USA natural gas prices in 2009, excluding the impact of financial hedges, reflects the changes in NYMEX, Rockies (Opal) and Texas (HSC) benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas production and mineral taxes for the USA of $54 million in 2009 decreased $140 million or 72 percent compared to 2008 primarily as a result of lower natural gas prices and high cost well tax credits.

Natural gas transportation and selling costs for the USA of $248 million in 2009 increased $13 million or 6 percent compared to 2008 primarily due to additional gathering and processing costs in East Texas.

Natural gas operating expenses for the USA of $159 million in 2009 were $48 million or 23 percent lower compared to 2008 as a result of lower long-term compensation costs due to the change in the EnCana share price, less activity resulting in lower workover costs, repairs and maintenance and reduced labour costs.

Crude Oil and NGLs

All of EnCana's liquids production in the USA relates to NGLs.

Three Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $80 million in the second quarter of 2009 compared to the same period in 2008 due to:

- A $63 million impact resulting from a 55 percent decrease in NGLs prices, excluding financial hedges; and
- A $17 million impact resulting from a 13 percent decrease in NGLs volumes.

USA NGLs prices decreased 55 percent to $47.27 per bbl in 2009 from $105.73 per bbl in 2008 primarily as a result of the change in the WTI benchmark price.

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.

Six Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $150 million in the six months of 2009 compared to the same period in 2008 due to:

- A $120 million impact resulting from a 60 percent decrease in NGLs prices, excluding financial hedges; and
- A $30 million impact resulting from a 13 percent decrease in NGLs volumes.

USA NGLs prices decreased 60 percent to $37.42 per bbl in 2009 from $94.14 per bbl in 2008 primarily as a result of the change in the WTI benchmark price.

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.

Capital Investment

USA capital investment of $925 million during the six months of 2009 was primarily focused on the East Texas and Jonah key resource plays, as well as Haynesville. The $254 million decrease compared to 2008 was primarily due to lower activity in the Piceance and Fort Worth key resource plays as well as lower capitalized long-term compensation costs offset by increased drilling and facility spending in Haynesville. The number of net wells drilled in the USA in the six months of 2009 decreased to 249 from 370 in 2008.

Integrated Oil

Foster Creek/Christina Lake Operations

EnCana is 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 current plan of the upstream business is to increase production capacity at Foster Creek/Christina Lake to approximately 218,000 bbls/d (on a 100 percent basis) of bitumen with the completion of current expansion phases.

Financial Results

Three Months Ended June 30, 2009 versus 2008

($ millions)	Oil 2009	Oil 2008
Revenues, Net of Royalties and Hedging	**$ 263**	$ 333
Realized Financial Hedging Gain (Loss)	**14**	(35)
Expenses		
Transportation and selling	**100**	123
Operating	**38**	50
Operating Cash Flow	**$ 139**	$ 125

Six Months Ended June 30, 2009 versus 2008

($ millions)	Oil 2009	Oil 2008
Revenues, Net of Royalties and Hedging	**$ 403**	$ 594
Realized Financial Hedging Gain (Loss)	**37**	(58)
Expenses		
Transportation and selling	**166**	243
Operating	**78**	91
Operating Cash Flow	**$ 196**	$ 202

Production Volumes

	Six Months Ended June 30		2009		2008				2007	
	2009	2008	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Crude Oil *(bbls/d)*	**37,720**	27,024	**40,677**	34,729	35,068	31,547	24,671	29,376	27,190	28,740
Total *(MMcfe/d)* (1)	**226**	162	**244**	208	210	189	148	176	163	172

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

Crude Oil

Three Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $21 million in the second quarter of 2009 compared to the same period in 2008 due to:

- A $170 million impact resulting from a decrease in crude oil prices, excluding financial hedges;
- A $28 million impact resulting from a decrease in average prices of condensate used for blending with heavy oil;

offset by:

- A $128 million impact resulting from a 59 percent increase in crude oil sales volumes attributable to a 65 percent increase in production volumes and changes in inventory levels; and
- Realized financial hedging gains primarily on condensate used for blending of $14 million in 2009 compared to losses of $35 million in 2008.

Foster Creek/Christina Lake bitumen prices decreased 49 percent to $47.34 per bbl in 2009 from $93.64 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices offset by a narrowing of the average differentials. WCS as a percentage of WTI was 88 percent in 2009 compared to 83 percent in 2008.

Crude oil transportation and selling costs of $100 million in 2009 decreased $23 million or 19 percent compared to 2008 primarily due to a decrease in average prices of condensate used for blending with heavy oil and variability in sales destinations and pipelines utilized to transport the product.

Crude oil operating costs of $38 million in 2009 were $12 million or 24 percent lower compared to 2008 mainly due to lower fuel gas costs and the lower U.S./Canadian dollar exchange rate.

Six Months Ended June 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $96 million in the six months of 2009 compared to the same period in 2008 due to:

- A $254 million impact resulting from a decrease in crude oil prices, excluding financial hedges;
- An $82 million impact resulting from a decrease in average prices of condensate used for blending with heavy oil;

offset by:

- A $145 million impact resulting from a 41 percent increase in crude oil sales volumes attributable to a 40 percent increase in production volumes and changes in inventory levels; and
- Realized financial hedging gains primarily on condensate used for blending of $37 million in 2009 compared to losses of $58 million in 2008.

Foster Creek/Christina Lake bitumen prices decreased 50 percent to $38.16 per bbl in 2009 from $76.10 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices offset by a narrowing of the average differentials. WCS as a percentage of WTI was 84 percent in 2009 compared to 81 percent in 2008.

Crude oil transportation and selling costs of $166 million in 2009 decreased $77 million or 32 percent compared to 2008 primarily due to a decrease in average prices of condensate used for blending with heavy oil and variability in sales destinations and pipelines utilized to transport the product.

Crude oil operating costs of $78 million in 2009 were $13 million or 14 percent lower compared to 2008 mainly due to lower fuel gas costs and the lower U.S./Canadian dollar exchange rate partially offset by increased workover costs.

Downstream Operations

Financial Results

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2009**	2008	**2009**	2008
Revenues	**$ 1,313**	$ 2,769	**$ 2,239**	$ 4,815
Expenses				
Operating	**112**	127	**230**	259
Purchased product	**1,047**	2,300	**1,796**	4,121
Operating Cash Flow	**$ 154**	$ 342	**$ 213**	$ 435

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).

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 bbls/d of crude oil, of which approximately 35,000 bbls/d is heavy crude oil (on a 100 percent basis) and approximately 45,000 bbls/d of NGLs (on a 100 percent basis).

The current plan of the downstream business is to refine approximately 275,000 bbls/d (on a 100 percent basis) of heavy crude oil (135,000 bbls/d of bitumen equivalent) to primarily motor fuels with the completion of the Wood River Coker and Refinery Expansion ("CORE") project in 2011. As at June 30, 2009, the Wood River and Borger refineries have processing capability to refine approximately 145,000 bbls/d (on a 100 percent basis) of heavy crude oil (70,000 bbls/d of bitumen equivalent).

The two refineries have a combined crude oil refining capacity of 452,000 bbls/d (on a 100 percent basis) and operated at an average 89 percent of that capacity during the second quarter of 2009 compared to 97 percent in 2008 and 89 percent during the six months of 2009 compared to 94 percent in 2008. Refinery crude utilization was lower in 2009 primarily due to unplanned refinery unit outages and maintenance activities. Refined products averaged 428,000 bbls/d (214,000 bbls/d net to EnCana) in the second quarter of 2009 compared to 464,000 bbls/d (232,000 bbls/d net to EnCana) in 2008 and 425,000 bbls/d (212,500 bbls/d net to EnCana) in the six months of 2009 compared to 450,000 bbls/d (225,000 bbls/d net to EnCana) in 2008.

Operating Cash Flow decreased $188 million or 55 percent in the second quarter of 2009 and decreased $222 million or 51 percent during the six months of 2009. Weaker refining margins combined with lower capacity utilization accounted for approximately $141 million and $95 million of the decrease in Operating Cash Flow in the second quarter and six months of 2009, respectively.

The decrease in crude prices results in lower inventory valuations and therefore comparatively higher purchased product costs of $70 million for the second quarter of 2009 and $141 million for the six months of 2009.

Operating costs which are comprised of labour, utilities and supplies are lower for both the second quarter and the six months of 2009 due to lower energy input costs partially offset by higher maintenance and turnaround costs.

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.

Gas production volumes from Athabasca were 72 MMcf/d in the second quarter of 2009 compared to 67 MMcf/d in 2008. The increase in production volumes was the result of current and prior period royalty expense reductions, offset by increased internal usage to supply a portion of the fuel gas requirements at Foster Creek and expected natural declines. Production volumes were 57 MMcf/d in the six months of 2009 compared to 66 MMcf/d in 2008 primarily due to increased internal usage of gas and expected natural declines.

Oil production volumes from Senlac were 1,800 bbls/d in the second quarter of 2009 compared to 3,009 bbls/d in 2008 and 1,933 bbls/d in the six months of 2009 compared to 3,261 bbls/d in 2008. The decrease in volumes at Senlac during the second quarter of 2009 was due to a prior period royalty expense increase, a planned turnaround and natural declines.

Capital Investment

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2009**	2008	**2009**	2008
Integrated Oil – Canada	**$ 103**	$ 144	**$ 229**	$ 352
Downstream Refining	**227**	122	**429**	177
Total Integrated Oil Division	**$ 330**	$ 266	**$ 658**	$ 529

Integrated Oil Division capital investment of $658 million during the six months of 2009 was primarily focused on continued development of the Foster Creek and Christina Lake key resource plays and on the CORE project at the Wood River refinery. The $129 million increase in capital investment in the six months of 2009 compared to the same period in 2008 was primarily due to:

- Spending related to the Wood River CORE project increased $213 million to $345 million in the six months of 2009 compared to $132 million in 2008. In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the CORE project. EnCana's 50 percent share of the CORE project is expected to cost approximately $1.8 billion and is anticipated to be completed and in full operation in 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and more than double heavy crude oil refining capacity to 240,000 bbls/d (on a 100 percent basis);

partially offset by:

- Lower facility costs with substantial completion of the Foster Creek Phases D and E expansions late in the fourth quarter of 2008. These expansions have increased plant capacity to 120,000 bbls/d (on a 100 percent basis);
- Lower drilling costs mainly due to drilling of fewer stratigraphic test wells net to EnCana (2009 – 39; 2008 – 134) at Foster Creek, Christina Lake, Borealis and Senlac related to the next phases of development; and
- The lower U.S./Canadian dollar exchange rate and lower capitalized long-term compensation costs.

Depreciation, Depletion and Amortization ("DD&A")

Total DD&A expenses of $980 million in the second quarter of 2009 decreased $117 million or 11 percent compared to 2008. Total DD&A expenses of $1,963 million in the six months of 2009 decreased $169 million or 8 percent compared to 2008.

Upstream DD&A

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

Three Months Ended June 30, 2009 versus 2008

Upstream DD&A expenses of $902 million in the second quarter of 2009 decreased $89 million or 9 percent compared to 2008 due to:

- DD&A expenses in Canada for 2009 were lower than 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate; and
- DD&A expenses in the USA for 2009 were lower than 2008 primarily due to lower DD&A rates resulting from lower future development costs and higher proved reserves.

Six Months Ended June 30, 2009 versus 2008

Upstream DD&A expenses of $1,802 million in the six months of 2009 decreased $155 million or 8 percent compared to 2008 due to:

- DD&A expenses in Canada for 2009 were lower than 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate;
- DD&A expenses in the USA for 2009 were lower than 2008 primarily due to lower DD&A rates resulting from lower future development costs and higher proved reserves;

partially offset by:

- Increased production volumes of 1 percent primarily in Foster Creek and Christina Lake as well as the USA.

Downstream DD&A

EnCana calculates DD&A on a straight-line basis over estimated service lives of approximately 25 years.

Downstream refining DD&A was $46 million in the second quarter of 2009 compared to $44 million in 2008 and $97 million in the six months of 2009 compared to $88 million in 2008 as a result of a full year of depreciation on prior year capital additions, as well as accelerated depreciation on certain assets expected to be retired sooner than originally anticipated.

Market Optimization

Financial Results

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2009**	2008	**2009**	2008
Revenues	**$ 366**	$ 647	**$ 858**	$ 1,272
Expenses				
Operating	**7**	8	**15**	19
Purchased product	**356**	628	**829**	1,235
Operating Cash Flow	**3**	11	**14**	18
Depreciation, depletion and amortization	**4**	4	**9**	8
Segment Income	**$ (1)**	$ 7	**$ 5**	$ 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.

Revenues and purchased product expenses decreased in the six months of 2009 compared to 2008 mainly due to decreased pricing partially offset by increases in volume required for Market Optimization.

Capital Investment

Market Optimization capital investment in the six months of 2009 and 2008 was focused on developing infrastructure for optimization activities and maintaining power generation facilities.

Corporate and Other

Financial Results

($ millions)	Three Months Ended June 30 2009	Three Months Ended June 30 2008	Six Months Ended June 30 2009	Six Months Ended June 30 2008
Revenues	**$ (1,113)**	$ (329)	**$ (980)**	$ (1,423)
Expenses				
Operating	**3**	(8)	**29**	(8)
Depreciation, depletion and amortization	**28**	58	**55**	79
Segment Income (Loss)	**$ (1,144)**	$ (379)	**$ (1,064)**	$ (1,494)

Revenues represent primarily unrealized mark-to-market gains or losses related to financial natural gas and liquids hedge contracts.

Operating expenses in the six months of 2009 relate to mark-to-market losses on long-term power generation contracts and downstream crude supply positions.

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

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

($ millions)	Three Months Ended June 30 2009	Three Months Ended June 30 2008	Six Months Ended June 30 2009	Six Months Ended June 30 2008
Revenues				
Natural Gas	**$ (1,099)**	$ (208)	**$ (941)**	$ (1,321)
Crude Oil	**(15)**	(120)	**(40)**	(103)
	(1,114)	(328)	**(981)**	(1,424)
Expenses	**4**	(10)	**26**	(13)
	(1,118)	(318)	**(1,007)**	(1,411)
Income Tax Expense (Recovery)	**(368)**	(83)	**(346)**	(439)
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ (750)**	$ (235)	**$ (661)**	$ (972)

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 16 to the Interim Consolidated Financial Statements.

Summary of Hedging Impacts on Net Earnings

($ millions)	Three Months Ended June 30 2009	Three Months Ended June 30 2008	Six Months Ended June 30 2009	Six Months Ended June 30 2008
Unrealized Mark-to-Market Gains (Losses), after-tax [1]	$ (750)	$ (235)	$ (661)	$ (972)
Realized Hedging Gains (Losses), after-tax [2]	900	(400)	1,599	(387)
Hedging Impacts on Net Earnings	$ 150	$ (635)	$ 938	$ (1,359)

(1) Includes primarily the reversal of accrued after-tax unrealized mark-to-market (gains) losses recognized in prior periods and change in the fair value of contracts in place at the beginning of the period as well as contracts entered into during the period.
(2) Included in Divisional financial results.

Consolidated Expenses

($ millions)	Three Months Ended June 30 2009	Three Months Ended June 30 2008	Six Months Ended June 30 2009	Six Months Ended June 30 2008
Administrative	$ 120	$ 225	$ 205	$ 381
Interest, net	129	147	233	281
Accretion of asset retirement obligation	19	20	36	41
Foreign exchange (gain) loss, net	(60)	(35)	(2)	60
(Gain) loss on divestitures	3	(17)	2	(17)

Administrative expenses decreased $105 million in the second quarter of 2009 compared to 2008 and $176 million in the six months of 2009 compared to 2008. The year-to-date decrease was primarily due to lower long-term compensation expenses of $126 million as a result of the change in the EnCana share price and the lower U.S./Canadian dollar exchange rate. In addition, 2008 expenses included a one time charge of $23 million for a legal settlement and higher costs related to the proposed corporate reorganization.

Net interest expense in the six months of 2009 decreased $48 million from 2008 primarily as a result of lower average outstanding debt and a lower weighted average interest rate. EnCana's total long-term debt, including current portion, decreased $1,431 million to $8,938 million at June 30, 2009 compared to $10,369 million at June 30, 2008. EnCana's year-to-date weighted average interest rate on outstanding debt was 5.2 percent in 2009 compared to 5.5 percent in 2008.

The foreign exchange gain of $2 million in the six months of 2009 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 the foreign exchange revaluation of the partnership contribution receivable, other foreign exchange gains and losses arising from the settlement of foreign currency transactions and the translation of EnCana's monetary assets and liabilities.

Income Tax

Total income tax expense in the six months of 2009 was $366 million, which was $511 million lower than the same period in 2008 due to lower net earnings before income tax, particularly in the US where the effective income tax rate is higher than in Canada.

Current income tax expense in the six months of 2009 was $560 million, which was $244 million lower than the same period in 2008. This reduction was due to lower operating cash flows.

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

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

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

Capital Investment

Corporate and Other capital investment in the six months of 2009 and 2008 was primarily directed to business information systems, leasehold improvements and office furniture.

Liquidity and Capital Resources

($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2009	2008	**2009**	2008
Net cash from (used in)				
Operating activities	**$ 1,955**	$ 1,996	**$ 3,786**	$ 3,754
Investing activities	**(1,307)**	(2,036)	**(3,095)**	(3,570)
Financing activities	**(956)**	(72)	**(749)**	44
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**9**	1	**5**	(3)
Increase (decrease) in cash and cash equivalents	**$ (299)**	$ (111)	**$ (53)**	$ 225

Operating Activities

Net cash from operating activities decreased $41 million in the second quarter of 2009 compared to 2008 and increased $32 million in the six months of 2009 compared to 2008. Cash Flow was $2,153 million during the second quarter of 2009 compared to $2,889 million in 2008 and $4,097 million during the six months of 2009 compared to $5,278 million in 2008. Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in other assets and liabilities and net changes in non-cash working capital, primarily from decreases in accounts receivable and accrued revenues and inventories offset by decreases in accounts payable and accrued liabilities and income tax payable.

Excluding the impact of current risk management assets and liabilities, the Company had a working capital deficit of $660 million at June 30, 2009 compared to $734 million at June 30, 2008. As is typical in the oil and gas industry, there is a timing difference between cash receipts from sales transactions and payments of trade payables, which often results in a working capital deficit. EnCana anticipates that it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used for investing activities in the six months of 2009 decreased $475 million compared to the same period in 2008. Capital expenditures, including property acquisitions, decreased $1,228 million in the six months of 2009 compared to 2008. Reasons for this change are discussed under the Net Capital Investment and Divisional Results sections of this MD&A. Increases in cash used for investing activities from net changes in non-cash working capital and net changes in investments and other were offset by reductions in capital expenditures.

Financing Activities

Net repayment of long-term debt in the six months of 2009 was $169 million compared to net issuance of $894 million for the same period in 2008. EnCana’s total long-term debt, including current portion, was $8,938 million at June 30, 2009 compared to $10,369 million at June 30, 2008.

On May 4, 2009, EnCana completed a public offering in the United States of senior unsecured notes in the aggregate principal amount of $500 million. The notes have a coupon rate of 6.5 percent and mature on May 15, 2019. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

EnCana maintains a Canadian and a U.S. dollar shelf prospectus and two committed bank credit facilities.

On May 21, 2009, EnCana renewed a shelf prospectus whereby it may issue from time to time up to C$2.0 billion, or the equivalent in foreign currencies, of debt securities in Canada. At June 30, 2009, C$2.0 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions.

EnCana has in place 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 United States. At June 30, 2009, $3.5 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions. The shelf prospectus was renewed in 2008 and expires in April 2010.

As at June 30, 2009, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.2 billion.

As at June 30, 2009, EnCana had available unused committed bank credit facilities in the amount of $3.4 billion. EnCana has in place a revolving bank credit facility for C$4.5 billion that remains committed through October 28, 2012. One of EnCana's U.S. subsidiaries has in place a revolving bank credit facility for $600 million, of which $565 million is accessible, that remains committed through February 28, 2013.

EnCana is currently in compliance with and anticipates that it will continue to be in compliance with all financial covenants under its credit facility agreements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor's Ratings Services has assigned a rating of "A-" with a "Negative" outlook, Moody's Investors Service has assigned a rating of "Baa2" with a "Stable" outlook, and DBRS Limited has assigned a rating of "A (low)" and has placed the rating "Under Review with Developing Implications". DBRS Limited placed the rating "Under Review" following the May 11, 2008 announcement of the proposed corporate reorganization.

EnCana has obtained regulatory approval under Canadian securities laws to purchase up to approximately 75.0 million Common Shares under a Normal Course Issuer Bid ("NCIB"). During the six months of 2009, EnCana did not purchase any of its Common Shares compared to 4.8 million Common Shares purchased for total consideration of approximately $326 million for the same period in 2008.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. Dividend payments were $601 million in the six months of 2009 and $600 million in the six months of 2008. These dividends were funded by Cash Flow.

Financial Metrics

	June 30 2009	December 31 2008
Debt to Capitalization (1)	**27%**	28%
Debt to Adjusted EBITDA (times) (2)	**0.7**	0.7

(1) Capitalization is a non-GAAP measure defined as Long-Term Debt including current portion plus Shareholders' Equity.
(2) Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Net Earnings from Continuing Operations before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Debt to Capitalization and 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 targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times.

At June 30, 2009, EnCana's Debt to Capitalization ratio was 27 percent (December 31, 2008 – 28 percent) and Debt to Adjusted EBITDA was 0.7 times (December 31, 2008 – 0.7 times).

Outstanding Share Data

(millions)	June 30 2009	December 31 2008
Common Shares outstanding, beginning of year	**750.4**	750.2
Common Shares issued under option plans	**0.2**	3.0
Common Shares issued from PSU Trust	**0.5**	-
Common Shares purchased	**-**	(2.8)
Common Shares outstanding, end of period	**751.1**	750.4
Weighted average Common Shares outstanding – diluted	**751.4**	751.8

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, 2009 and 2008.

Employees have been granted options to purchase Common Shares under various plans. At June 30, 2009, approximately 0.3 million options without Tandem Share Appreciation Rights ("TSARs") attached were outstanding, all of which are exercisable.

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 deciding to realize the value of their options have exercised their TSARs to receive a cash payment. At June 30, 2009, approximately 21.6 million options with TSARs attached were outstanding, of which 12.5 million are exercisable.

In 2007, 2008 and 2009 EnCana also granted Performance TSARs, which vest and expire under the same terms and service conditions as TSARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited. At June 30, 2009, approximately 18.9 million Performance TSARs were outstanding, of which 3.8 million are exercisable.

In 2008, EnCana granted Share Appreciation Rights ("SARs") and Performance SARs to certain employees, which entitle 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 are 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, 2009, approximately 5.9 million SARs and Performance SARs were outstanding, of which 0.6 million are exercisable.

In April 2009, the remaining 0.5 million Common Shares held in trust relating to EnCana's PSU plan were sold for total consideration of $25 million. Of the amount received, $19 million was credited to Share capital and $6 million to Paid in surplus, representing the excess consideration received over the original price of the Common Shares acquired by the trust. Effective May 15, 2009, EnCana's PSU plan was complete and the trust agreement was terminated.

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 principal debt obligations of $8,964 million at June 30, 2009 are $1,039 million in obligations related to Commercial Paper. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for the periods disclosed in the Liquidity and Capital Resources section of this MD&A. Further details regarding EnCana's long-term debt are described in Note 10 to the Interim Consolidated Financial Statements.

The Company expects its 2009 commitments to be funded from Cash Flow.

As at June 30, 2009, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 91 Bcf at a weighted average price of $3.90 per Mcf.

Leases

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

Variable Interest Entities ("VIEs")

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which 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 Haynesville represented an interest in a VIE from September 25, 2008 to March 24, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Haynesville. On March 24, 2009, when the arrangement with Brown Haynesville was completed, the assets were transferred to EnCana.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million, reducing the qualifying like kind exchange to approximately $300 million. The relationship with Brown Southwest represented an interest in a VIE from July 23, 2008 to January 19, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Southwest. On January 19, 2009, when the arrangement with Brown Southwest 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. All but one of these lawsuits has been settled prior to 2009, without admitting any liability in the lawsuits.

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, on January 1, 2009, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064 "Goodwill and Intangible Assets". The adoption of this standard has had no material impact on EnCana's Consolidated Financial Statements. Additional information on the effects of the implementation of the new standard can be found in Note 2 to the Interim Consolidated Financial Statements.

Recent Accounting Pronouncements

International Financial Reporting Standards ("IFRS")
In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information.

The key elements of EnCana's changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

The Company has substantially completed analyzing accounting policy alternatives and outlining process and system design changes required for significant areas of impact. The significant areas of impact continue to include property, plant & equipment ("PP&E"), impairment testing, asset retirement obligation, stock-based compensation, employee future benefits, and income taxes. The areas identified as being significant have the greatest potential impact to the Company's financial statements or the greatest risk in terms of complexity to implement.

The Company expects one of the most significant impacts of the IFRS changeover will be in the accounting for certain upstream activities. Under Canadian GAAP, EnCana follows the CICA's guideline on full cost accounting. In moving to IFRS, EnCana will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs. Upstream DD&A will be calculated at a lower unit of account level than the current country cost centre basis. In addition, impairment testing will be performed at a lower level than the current country cost centre basis.

In September 2008, the International Accounting Standards Board ("IASB") issued an exposure draft outlining additional exemptions for first-time adopters of IFRS. Included in the exposure draft is an exemption which would permit full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) over reserves to the unit of account level upon transition to IFRS. This exemption would relieve the Company from retrospective application of IFRS for upstream PP&E. In May 2009, the IASB agreed to commence drafting the final amendments for the proposed exemption, which EnCana intends to adopt if it is approved and adopted into IFRS. The Company is also evaluating the impact of other first-time adoption exemptions available upon initial transition to IFRS.

EnCana will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company's Consolidated Financial Statements is not reasonably determinable at this time.

Business Combinations
As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1582 "Business Combinations", which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations.

Consolidated Financial Statements
As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1601 "Consolidated Financials Statements", which together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Non-controlling Interests
As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1602 "Non-controlling Interests", which establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to

a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Risk Management

EnCana's business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, are impacted by risks that are categorized as follows:

- financial risks including market risks (such as commodity price, foreign exchange and interest rates), credit and liquidity;
- operational risks including capital, operating and reserves replacement risks; and
- safety, environmental and regulatory risks.

EnCana takes a proactive approach in identifying and managing risks that can affect the Company. Mitigation of these risks include, but are not limited to, the use of financial instruments and physical contracts, 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, 2008 Management's Discussion and Analysis and Note 16 to the Interim Consolidated Financial Statements.

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 emission reduction plans in the future. 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 and capital costs in order to comply with GHG emissions legislation. However, EnCana will continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

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

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' was 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 started at C$10 per tonne of carbon equivalent emissions, rising by C$5 per tonne a year for the next four years. The forecast cost of carbon associated with the British Columbia regulations is not material to EnCana at this time and is being actively managed.

The American Clean Energy and Security Act (ACESA) was passed by the House of Representatives on June 26, 2009. This climate change legislation would establish a GHG cap-and-trade system and provide incentives for the development of renewable energy. The Act aims to reduce GHG emissions by 17 percent from 2005 levels by 2020, and 83 percent by 2050. EnCana is following the developments of this complex bill very closely as it moves to the Senate – both for the impact it may have on energy production and use, as well as the potential it holds to expand markets for the use of natural gas as a clean burning energy alternative.

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:

- significant production weighting in natural gas;
- recognition as an industry leader in CO_2 sequestration;

- focus on energy efficiency and the development of technology to reduce GHG emissions;
- involvement in the creation of industry best practices; and
- 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 composed 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 the Company's steam to oil ratio help to support and drive its focus on cost reduction.
2. Respond to Price Signals
   As regulatory regimes for GHGs develop in the jurisdictions where EnCana works, inevitably price signals begin to emerge. The Company has initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of its 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, EnCana is also attempting, where appropriate, 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, the Company gains useful knowledge that allows it to explore different strategies for managing its emissions and costs. These scenarios influence EnCana's long range planning and its analyses on the implications of regulatory trends.

EnCana incorporates the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on its strategy, with a current price range from $15 to $65 per tonne of emissions applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. EnCana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, EnCana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

EnCana recognizes that there is a cost associated with carbon emissions. EnCana is confident that greenhouse gas regulations and the cost of carbon at various price levels have been adequately considered as part of its business planning and scenarios analysis. EnCana believes that the resource play strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. 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 the Company's website at www.encana.com.

Alberta's New Royalty Programs
The Alberta Government's New Royalty Framework ("NRF") and Transitional Royalty Program ("TRP") came into effect on January 1, 2009. The NRF established new royalties for conventional oil, natural gas and bitumen that are linked to commodity prices, well production volumes and well depths for gas wells and oil quality for oil wells. These new rates apply to both new and existing conventional oil and gas activities and enhanced oil recovery projects in Alberta. The TRP allows for a one time option of selecting between transitional rates and the NRF rates on new natural gas or conventional oil wells drilled between 1,000 metres to 3,500 metres in depth. The TRP rates would apply until January 1, 2014, at which time all wells would be moved to the NRF.

On March 3, 2009, the Alberta Government announced a stimulus package Energy Incentive Program that focuses on keeping drilling and service crews at work. There are two components of this program that affect EnCana; the Drilling Royalty Credit and New Well Incentive. The Drilling Royalty Credit is a depth related credit for the drilling of new conventional oil and gas wells between April 1, 2009 and March 31, 2011. The New Well Incentive provides a 5 percent royalty rate for new gas and conventional oil wells that come on production between April 1, 2009 and March 31, 2011 for a period of 12 months or 0.5 billion cubic feet equivalent ("Bcfe") for gas wells or 50,000 barrels of oil equivalent ("BOE") for oil wells, whichever comes first.

Impacts as a result of the NRF, TRP and Energy Incentive Programs change the economics of operating in Alberta, and accordingly, are reflected in EnCana's capital programs.

Outlook

During the current challenging economic environment, EnCana is highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, further optimizing capital investments and continuing to pay a stable dividend to shareholders.

EnCana monitors the risks under its control and has policies in place to mitigate those risks. EnCana is managing commodity price risk through its financial risk management program designed to help ensure financial resilience and flexibility and is closely monitoring interest, credit and counterparty risk. In addition, the Company continues to monitor expenses and capital programs and maintain flexibility to adjust to changing economic circumstances. EnCana has planned a conservative, prudent and flexible capital program in 2009 that currently targets total natural gas and oil production at approximately 2008 levels and advances the Company's multi-year projects. EnCana expects to continue to fund the Foster Creek and Christina Lake expansion projects, Wood River CORE project and other capital projects at the present time. EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times. At June 30, 2009 the Company's Debt to Capitalization ratio was 27 percent and Debt to Adjusted EBITDA was 0.7 times.

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 natural gas represents an abundant, secure, long-term supply of energy to meet North American needs.

Volatility in crude oil prices is expected to continue throughout 2009 as a result of market uncertainties over supply and refining, changes in demand due to the overall state of the world economies, OPEC actions and the worldwide credit and liquidity crisis. Canadian crude oil prices will face added uncertainty due to the risk of refinery disruptions in an already tight United States Midwest market and growing domestic production could result in pipeline constraints out of Western Canada.

The Company expects its 2009 capital investment program to be funded from Cash Flow.

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

EnCana's results are affected by external market and risk 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 2009 results is available in the Corporate Guidance on the Company's website at www.encana.com. EnCana updated its Corporate Guidance to reflect the impact on operations of expected conditions for 2009. EnCana's news release dated July 23, 2009 and financial statements are available on www.sedar.com.

Advisory

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: projected natural gas and oil production levels for 2009; projections relating to the adequacy of the Company's provision for taxes; the expected impact of the Alberta Royalty Framework and Transitional Royalty Program; projections with respect to natural gas production from unconventional resource plays and in-situ oil resources including with respect to the Foster Creek and Christina Lake projects, the CORE project and planned expansions of the Company's downstream heavy oil processing capacity and the capital costs and expected timing of the same; projections relating to the volatility of natural gas and crude oil prices in 2009 and beyond and the reasons therefor; the Company's projected capital investment levels for 2009, the flexibility of capital spending plans 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 changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on the Company's operations and 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; the Company's continued compliance with financial covenants under its credit facilities; projections relating to the Company's natural gas, crude oil and natural gas liquids reserves; the Company's ability to pay its creditors, suppliers, commitments and fund its 2009 capital program and pay dividends to shareholders; the impact of the current business market conditions, including the economic recession and financial market turmoil on the Company's operations and expected results; the effect of the Company's risk mitigation policies, systems, processes and insurance program; the Company's expectations for future Debt to Capitalization and Debt to Adjusted EBITDA ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards, including IFRS, on the Company and its Consolidated Financial Statements; and projections that natural gas represents an abundant, secure, long-term supply of energy to meet North American needs. 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 crude oil; risks associated with technology and the application thereof to the business of the Company; 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, greenhouse gas, carbon accounting 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.

Forward-looking information respecting anticipated 2009 cash flow, operating cash flow and pre-tax cash flow for EnCana is based upon achieving average production of oil and gas for 2009 of approximately 4.4 to 4.8 Bcfe/d, year-to-date actuals and forward curve estimates for commodity prices and U.S./Canadian dollar foreign exchange rate as of June 30, 2009, 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.

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 23, 2009, which 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 that 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 Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

Non-GAAP Measures
Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Cash Flow per share – diluted, Free Cash Flow, Operating Earnings, Operating Earnings per share – diluted, Adjusted EBITDA, Debt, 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", "our" and "its" 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, **2009**	Three Months Ended June 30, 2008	Six Months Ended June 30, **2009**	Six Months Ended June 30, 2008
Revenues, Net of Royalties	*(Note 4)*	**$ 3,762**	$ 7,422	**$ 8,370**	$ 12,856
Expenses	*(Note 4)*				
Production and mineral taxes		**32**	154	**93**	268
Transportation and selling		**321**	427	**614**	839
Operating		**512**	709	**1,065**	1,405
Purchased product		**1,385**	2,882	**2,594**	5,275
Depreciation, depletion and amortization		**980**	1,097	**1,963**	2,132
Administrative		**120**	225	**205**	381
Interest, net	*(Note 6)*	**129**	147	**233**	281
Accretion of asset retirement obligation	*(Note 11)*	**19**	20	**36**	41
Foreign exchange (gain) loss, net	*(Note 7)*	**(60)**	(35)	**(2)**	60
(Gain) loss on divestitures	*(Note 5)*	**3**	(17)	**2**	(17)
		3,441	5,609	**6,803**	10,665
Net Earnings Before Income Tax		**321**	1,813	**1,567**	2,191
Income tax expense	*(Note 8)*	**82**	592	**366**	877
Net Earnings		**$ 239**	$ 1,221	**$ 1,201**	$ 1,314
Net Earnings per Common Share	*(Note 15)*				
Basic		**$ 0.32**	$ 1.63	**$ 1.60**	$ 1.75
Diluted		**$ 0.32**	$ 1.63	**$ 1.60**	$ 1.75

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statement of Retained Earnings *(unaudited)*

($ millions)		Six Months Ended June 30, 2009	2008
Retained Earnings, Beginning of Year		**$ 17,584**	$ 13,082
Net Earnings		**1,201**	1,314
Dividends on Common Shares		**(601)**	(600)
Charges for Normal Course Issuer Bid	*(Note 12)*	**-**	(243)
Retained Earnings, End of Period		**$ 18,184**	$ 13,553

Consolidated Statement of Comprehensive Income *(unaudited)*

($ millions)	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Net Earnings	**$ 239**	$ 1,221	**$ 1,201**	$ 1,314
Other Comprehensive Income, Net of Tax				
Foreign Currency Translation Adjustment	**916**	48	**645**	(352)
Comprehensive Income	**$ 1,155**	$ 1,269	**$ 1,846**	$ 962

Consolidated Statement of Accumulated Other Comprehensive Income *(unaudited)*

($ millions)	Six Months Ended June 30, 2009	2008
Accumulated Other Comprehensive Income, Beginning of Year	**$ 833**	$ 3,063
Foreign Currency Translation Adjustment	**645**	(352)
Accumulated Other Comprehensive Income, End of Period	**$ 1,478**	$ 2,711

See accompanying Notes to Consolidated Financial Statements.

Consolidated Balance Sheet *(unaudited)*

($ millions)		**As at June 30, 2009**	As at December 31, 2008
Assets			
Current Assets			
Cash and cash equivalents		**$ 330**	$ 383
Accounts receivable and accrued revenues		**1,472**	1,568
Current portion of partnership contribution receivable		**321**	313
Risk management	*(Note 16)*	**1,927**	2,818
Inventories	*(Note 9)*	**710**	520
		4,760	5,602
Property, Plant and Equipment, net	*(Note 4)*	**37,377**	35,424
Investments and Other Assets		**955**	727
Partnership Contribution Receivable		**2,672**	2,834
Risk Management	*(Note 16)*	**44**	234
Goodwill		**2,530**	2,426
	(Note 4)	**$ 48,338**	$ 47,247
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,401**	$ 2,871
Income tax payable		**527**	424
Current portion of partnership contribution payable		**315**	306
Risk management	*(Note 16)*	**14**	43
Current portion of long-term debt	*(Note 10)*	**250**	250
		3,507	3,894
Long-Term Debt	*(Note 10)*	**8,688**	8,755
Other Liabilities		**903**	576
Partnership Contribution Payable		**2,697**	2,857
Risk Management	*(Note 16)*	**26**	7
Asset Retirement Obligation	*(Note 11)*	**1,325**	1,265
Future Income Taxes		**6,945**	6,919
		24,091	24,273
Shareholders' Equity			
Share capital	*(Note 12)*	**4,579**	4,557
Paid in surplus	*(Note 12)*	**6**	-
Retained earnings		**18,184**	17,584
Accumulated other comprehensive income		**1,478**	833
Total Shareholders' Equity		**24,247**	22,974
		$ 48,338	$ 47,247

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows *(unaudited)*

($ millions)		Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating Activities					
Net earnings		**$ 239**	$ 1,221	**$ 1,201**	$ 1,314
Depreciation, depletion and amortization		**980**	1,097	**1,963**	2,132
Future income taxes	*(Note 8)*	**(231)**	152	**(194)**	73
Unrealized (gain) loss on risk management	*(Note 16)*	**1,118**	318	**1,007**	1,411
Unrealized foreign exchange (gain) loss		**(69)**	(11)	**(49)**	65
Accretion of asset retirement obligation	*(Note 11)*	**19**	20	**36**	41
(Gain) loss on divestitures	*(Note 5)*	**3**	(17)	**2**	(17)
Other		**94**	109	**131**	259
Net change in other assets and liabilities		**9**	(171)	**23**	(264)
Net change in non-cash working capital		**(207)**	(722)	**(334)**	(1,260)
Cash From Operating Activities		**1,955**	1,996	**3,786**	3,754
Investing Activities					
Capital expenditures	*(Note 4)*	**(1,088)**	(1,996)	**(2,675)**	(3,903)
Proceeds from divestitures	*(Note 5)*	**20**	79	**53**	151
Corporate acquisition	*(Note 5)*	**(24)**	-	**(24)**	-
Net change in investments and other		**(28)**	(18)	**(170)**	(9)
Net change in non-cash working capital		**(187)**	(101)	**(279)**	191
Cash (Used in) Investing Activities		**(1,307)**	(2,036)	**(3,095)**	(3,570)
Financing Activities					
Net issuance (repayment) of revolving long-term debt		**(1,170)**	426	**(665)**	367
Issuance of long-term debt	*(Note 10)*	**496**	-	**496**	723
Repayment of long-term debt		**-**	(196)	**-**	(196)
Issuance of common shares	*(Note 12)*	**19**	13	**21**	76
Purchase of common shares	*(Note 12)*	**-**	(15)	**-**	(326)
Dividends on common shares		**(301)**	(300)	**(601)**	(600)
Cash From (Used in) Financing Activities		**(956)**	(72)	**(749)**	44
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**9**	1	**5**	(3)
Increase (Decrease) in Cash and Cash Equivalents		**(299)**	(111)	**(53)**	225
Cash and Cash Equivalents, Beginning of Period		**629**	889	**383**	553
Cash and Cash Equivalents, End of Period		**$ 330**	$ 778	**$ 330**	$ 778

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 ("GAAP"). EnCana's operations are in the business of the exploration for, the development of, and the 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, 2008, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. Certain information and disclosures normally required to be included in the notes to the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, 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, 2008.

2. Changes in Accounting Policies and Practices

On January 1, 2009, the Company adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook Section:

- "Goodwill and Intangible Assets", Section 3064. The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard has had no material impact on EnCana's Consolidated Financial Statements.

3. Recent Accounting Pronouncements

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information. The impact of IFRS on the Company's Consolidated Financial Statements is not reasonably determinable at this time.

As of January 1, 2011, EnCana will be required to adopt the following CICA Handbook sections:

- "Business Combinations", Section 1582, which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations.

- "Consolidated Financial Statements", Section 1601, which together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

- "Non-controlling Interests", Section 1602, which establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Segmented Information

The Company's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and NGLs and other related activities within the Canadian cost centre.

- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.

- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.

- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include 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 and Other** mainly 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 sells substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

On December 31, 2008, EnCana updated its segmented reporting to present the upstream Canadian and United States cost centres and Downstream Refining as separate reportable segments. This resulted in EnCana presenting the Canadian portion of the Integrated Oil Division as part of the Canada segment. Previously, this was aggregated and presented in the Integrated Oil segment. Prior periods have been restated to reflect the new presentation.

EnCana has a decentralized decision making and reporting structure. Accordingly, the Company is organized into Divisions as follows:

- **Canadian Plains** Division includes natural gas and crude oil exploration, development and production assets located in eastern Alberta and Saskatchewan.

- **Canadian Foothills** Division includes natural gas exploration, development and production assets located in western Alberta and British Columbia as well as the Company's Canadian offshore assets.

- **USA** Division includes natural gas exploration, development and production assets located in the United States and comprises the USA segment described above.

- **Integrated Oil** Division is the combined total of Integrated Oil – Canada and Downstream Refining. Integrated Oil – Canada includes the Company's exploration for, and development and production of bitumen using enhanced recovery methods. Integrated Oil – Canada is composed of EnCana's interests in the FCCL Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Segmented Information (continued)

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

Segment and Geographic Information

	Canada		USA		Downstream Refining	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 2,070**	$ 2,810	**$ 1,126**	$ 1,525	**$ 1,313**	$ 2,769
Expenses						
Production and mineral taxes	**17**	36	**15**	118	**-**	-
Transportation and selling	**196**	307	**125**	120	**-**	-
Operating	**291**	396	**99**	186	**112**	127
Purchased product	**(18)**	(46)	**-**	-	**1,047**	2,300
	1,584	2,117	**887**	1,101	**154**	342
Depreciation, depletion and amortization	**523**	570	**379**	421	**46**	44
Segment Income (Loss)	**$ 1,061**	$ 1,547	**$ 508**	$ 680	**$ 108**	$ 298

	Market Optimization		Corporate & Other		Consolidated	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 366**	$ 647	**$ (1,113)**	$ (329)	**$ 3,762**	$ 7,422
Expenses						
Production and mineral taxes	**-**	-	**-**	-	**32**	154
Transportation and selling	**-**	-	**-**	-	**321**	427
Operating	**7**	8	**3**	(8)	**512**	709
Purchased product	**356**	628	**-**	-	**1,385**	2,882
	3	11	**(1,116)**	(321)	**1,512**	3,250
Depreciation, depletion and amortization	**4**	4	**28**	58	**980**	1,097
Segment Income (Loss)	**$ (1)**	$ 7	**$ (1,144)**	$ (379)	**532**	2,153
Administrative					**120**	225
Interest, net					**129**	147
Accretion of asset retirement obligation					**19**	20
Foreign exchange (gain) loss, net					**(60)**	(35)
(Gain) loss on divestitures					**3**	(17)
					211	340
Net Earnings Before Income Tax					**321**	1,813
Income tax expense					**82**	592
Net Earnings					**$ 239**	$ 1,221

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Segmented Information (continued)

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

Product and Divisional Information

Canada Segment

	Canadian Plains		Canadian Foothills		Integrated Oil - Canada		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 820**	$ 1,275	**$ 907**	$ 1,189	**$ 343**	$ 346	**$ 2,070**	$ 2,810
Expenses								
Production and mineral taxes	**11**	24	**6**	12	**-**	-	**17**	36
Transportation and selling	**53**	115	**38**	54	**105**	138	**196**	307
Operating	**108**	147	**133**	180	**50**	69	**291**	396
Purchased product	**-**	-	**-**	-	**(18)**	(46)	**(18)**	(46)
Operating Cash Flow	**$ 648**	$ 989	**$ 730**	$ 943	**$ 206**	$ 185	**$ 1,584**	$ 2,117

Canadian Plains Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 475**	$ 629	**$ 341**	$ 644	**$ 4**	$ 2	**$ 820**	$ 1,275
Expenses								
Production and mineral taxes	**5**	13	**6**	11	**-**	-	**11**	24
Transportation and selling	**10**	18	**43**	97	**-**	-	**53**	115
Operating	**51**	74	**55**	72	**2**	1	**108**	147
Operating Cash Flow	**$ 409**	$ 524	**$ 237**	$ 464	**$ 2**	$ 1	**$ 648**	$ 989

Canadian Foothills Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 823**	$ 1,000	**$ 74**	$ 174	**$ 10**	$ 15	**$ 907**	$ 1,189
Expenses								
Production and mineral taxes	**5**	11	**1**	1	**-**	-	**6**	12
Transportation and selling	**37**	51	**1**	3	**-**	-	**38**	54
Operating	**124**	163	**6**	12	**3**	5	**133**	180
Operating Cash Flow	**$ 657**	$ 775	**$ 66**	$ 158	**$ 7**	$ 10	**$ 730**	$ 943

USA Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,044**	$ 1,308	**$ 50**	$ 130	**$ 32**	$ 87	**$ 1,126**	$ 1,525
Expenses								
Production and mineral taxes	**11**	107	**4**	11	**-**	-	**15**	118
Transportation and selling	**125**	120	**-**	-	**-**	-	**125**	120
Operating	**77**	106	**-**	-	**22**	80	**99**	186
Operating Cash Flow	**$ 831**	$ 975	**$ 46**	$ 119	**$ 10**	$ 7	**$ 887**	$ 1,101

Integrated Oil Division

	Oil *		Downstream Refining		Other *		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 277**	$ 298	**$ 1,313**	$ 2,769	**$ 66**	$ 48	**$ 1,656**	$ 3,115
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**-**	-	**-**	-
Transportation and selling	**100**	123	**-**	-	**5**	15	**105**	138
Operating	**38**	50	**112**	127	**12**	19	**162**	196
Purchased product	**-**	-	**1,047**	2,300	**(18)**	(46)	**1,029**	2,254
Operating Cash Flow	**$ 139**	$ 125	**$ 154**	$ 342	**$ 67**	$ 60	**$ 360**	$ 527

* Oil and Other comprise Integrated Oil - Canada. Other includes production of natural gas and bitumen from the Athabasca and Senlac properties.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Segmented Information (continued)

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

Segment and Geographic Information

	Canada		USA		Downstream Refining	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 3,953**	$ 5,313	**$ 2,300**	$ 2,879	**$ 2,239**	$ 4,815
Expenses						
Production and mineral taxes	**32**	54	**61**	214	**-**	-
Transportation and selling	**366**	604	**248**	235	**-**	-
Operating	**577**	780	**214**	355	**230**	259
Purchased product	**(31)**	(81)	**-**	-	**1,796**	4,121
	3,009	3,956	**1,777**	2,075	**213**	435
Depreciation, depletion and amortization	**1,007**	1,139	**795**	818	**97**	88
Segment Income (Loss)	**$ 2,002**	$ 2,817	**$ 982**	$ 1,257	**$ 116**	$ 347

	Market Optimization		Corporate & Other		Consolidated	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 858**	$ 1,272	**$ (980)**	$ (1,423)	**$ 8,370**	$ 12,856
Expenses						
Production and mineral taxes	**-**	-	**-**	-	**93**	268
Transportation and selling	**-**	-	**-**	-	**614**	839
Operating	**15**	19	**29**	(8)	**1,065**	1,405
Purchased product	**829**	1,235	**-**	-	**2,594**	5,275
	14	18	**(1,009)**	(1,415)	**4,004**	5,069
Depreciation, depletion and amortization	**9**	8	**55**	79	**1,963**	2,132
Segment Income (Loss)	**$ 5**	$ 10	**$ (1,064)**	$ (1,494)	**2,041**	2,937
Administrative					**205**	381
Interest, net					**233**	281
Accretion of asset retirement obligation					**36**	41
Foreign exchange (gain) loss, net					**(2)**	60
(Gain) loss on divestitures					**2**	(17)
					474	746
Net Earnings Before Income Tax					**1,567**	2,191
Income tax expense					**366**	877
Net Earnings					**$ 1,201**	$ 1,314

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Segmented Information (continued)

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

Product and Divisional Information

Canada Segment	Canadian Plains 2009	Canadian Plains 2008	Canadian Foothills 2009	Canadian Foothills 2008	Integrated Oil - Canada 2009	Integrated Oil - Canada 2008	Total 2009	Total 2008
Revenues, Net of Royalties	**$ 1,595**	$ 2,416	**$ 1,822**	$ 2,264	**$ 536**	$ 633	**$ 3,953**	$ 5,313
Expenses								
Production and mineral taxes	**21**	37	**11**	16	**-**	1	**32**	54
Transportation and selling	**115**	224	**75**	110	**176**	270	**366**	604
Operating	**211**	289	**263**	358	**103**	133	**577**	780
Purchased product	**-**	-	**-**	-	**(31)**	(81)	**(31)**	(81)
Operating Cash Flow	**$ 1,248**	$ 1,866	**$ 1,473**	$ 1,780	**$ 288**	$ 310	**$ 3,009**	$ 3,956

Canadian Plains Division	Gas 2009	Gas 2008	Oil & NGLs 2009	Oil & NGLs 2008	Other 2009	Other 2008	Total 2009	Total 2008
Revenues, Net of Royalties	**$ 996**	$ 1,219	**$ 593**	$ 1,193	**$ 6**	$ 4	**$ 1,595**	$ 2,416
Expenses								
Production and mineral taxes	**8**	18	**13**	19	**-**	-	**21**	37
Transportation and selling	**21**	37	**94**	187	**-**	-	**115**	224
Operating	**102**	147	**106**	140	**3**	2	**211**	289
Operating Cash Flow	**$ 865**	$ 1,017	**$ 380**	$ 847	**$ 3**	$ 2	**$ 1,248**	$ 1,866

Canadian Foothills Division	Gas 2009	Gas 2008	Oil & NGLs 2009	Oil & NGLs 2008	Other 2009	Other 2008	Total 2009	Total 2008
Revenues, Net of Royalties	**$ 1,671**	$ 1,909	**$ 131**	$ 322	**$ 20**	$ 33	**$ 1,822**	$ 2,264
Expenses								
Production and mineral taxes	**9**	14	**2**	2	**-**	-	**11**	16
Transportation and selling	**71**	104	**4**	6	**-**	-	**75**	110
Operating	**244**	324	**12**	23	**7**	11	**263**	358
Operating Cash Flow	**$ 1,347**	$ 1,467	**$ 113**	$ 291	**$ 13**	$ 22	**$ 1,473**	$ 1,780

USA Division	Gas 2009	Gas 2008	Oil & NGLs 2009	Oil & NGLs 2008	Other 2009	Other 2008	Total 2009	Total 2008
Revenues, Net of Royalties	**$ 2,162**	$ 2,491	**$ 79**	$ 229	**$ 59**	$ 159	**$ 2,300**	$ 2,879
Expenses								
Production and mineral taxes	**54**	194	**7**	20	**-**	-	**61**	214
Transportation and selling	**248**	235	**-**	-	**-**	-	**248**	235
Operating	**159**	207	**-**	-	**55**	148	**214**	355
Operating Cash Flow	**$ 1,701**	$ 1,855	**$ 72**	$ 209	**$ 4**	$ 11	**$ 1,777**	$ 2,075

Integrated Oil Division	Oil * 2009	Oil * 2008	Downstream Refining 2009	Downstream Refining 2008	Other * 2009	Other * 2008	Total 2009	Total 2008
Revenues, Net of Royalties	**$ 440**	$ 536	**$ 2,239**	$ 4,815	**$ 96**	$ 97	**$ 2,775**	$ 5,448
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**-**	1	**-**	1
Transportation and selling	**166**	243	**-**	-	**10**	27	**176**	270
Operating	**78**	91	**230**	259	**25**	42	**333**	392
Purchased product	**-**	-	**1,796**	4,121	**(31)**	(81)	**1,765**	4,040
Operating Cash Flow	**$ 196**	$ 202	**$ 213**	$ 435	**$ 92**	$ 108	**$ 501**	$ 745

* Oil and Other comprise Integrated Oil - Canada. Other includes production of natural gas and bitumen from the Athabasca and Senlac properties.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Segmented Information (continued)

Capital Expenditures

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	**2009**	2008
Capital				
Canadian Plains	**$ 69**	$ 158	**$ 228**	$ 420
Canadian Foothills	**280**	583	**745**	1,363
Integrated Oil - Canada	**103**	144	**229**	352
Canada	**452**	885	**1,202**	2,135
USA	**385**	660	**925**	1,179
Downstream Refining	**227**	122	**429**	177
Market Optimization	**-**	5	**(3)**	7
Corporate & Other	**14**	46	**33**	69
	1,078	1,718	**2,586**	3,567
Acquisition Capital				
Canadian Plains	**1**	-	**1**	-
Canadian Foothills	**1**	20	**74**	92
Canada	**2**	20	**75**	92
USA	**8**	258	**14**	244
	10	278	**89**	336
Total	**$ 1,088**	$ 1,996	**$ 2,675**	$ 3,903

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which 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 Haynesville represented an interest in a Variable Interest Entity ("VIE") from September 25, 2008 to March 24, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Haynesville. On March 24, 2009, when the arrangement with Brown Haynesville was completed, the assets were transferred to EnCana.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million, reducing the qualifying like kind exchange to approximately $300 million. The relationship with Brown Southwest represented an interest in a VIE from July 23, 2008 to January 19, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Southwest. On January 19, 2009, when the arrangement with Brown Southwest was completed, the assets were transferred to EnCana.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Segmented Information (continued)

Property, Plant and Equipment and Total Assets by Segment

	Property, Plant and Equipment		Total Assets	
	As at		As at	
	June 30, 2009	December 31, 2008	**June 30, 2009**	December 31, 2008
Canada	**$ 18,362**	$ 17,082	**$ 24,889**	$ 23,419
USA	**13,677**	13,541	**14,752**	14,635
Downstream Refining	**4,376**	4,032	**5,075**	4,637
Market Optimization	**134**	140	**419**	429
Corporate & Other	**828**	629	**3,203**	4,127
Total	**$ 37,377**	$ 35,424	**$ 48,338**	$ 47,247

On February 9, 2007, EnCana announced that it had entered into a 25 year lease agreement with a third party developer for The Bow office project. As at June 30, 2009, Corporate and Other Property, Plant and Equipment and Total Assets includes EnCana's accrual to date of $442 million ($252 million at December 31, 2008) 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, 2009, Canada Property, Plant, and Equipment and Total Assets includes EnCana's accrual to date of $311 million ($199 million at December 31, 2008) 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.

5. Acquisitions and Divestitures

Acquisitions

On May 5, 2009, the Company acquired the common shares of Kerogen Resources Canada, ULC for net cash consideration of $24 million. The acquisition included $37 million of property, plant and equipment and the assumption of $6 million of current liabilities and $7 million of future income taxes. The operations are included in the Canadian Foothills Division.

Divestitures

Total year-to-date proceeds received on the sale of assets were $53 million (2008 - $151 million). The significant items are described below:

Canada

In 2009, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of $44 million (2008 - $70 million) in Canadian Foothills and did not complete any divestitures in Canadian Plains (2008 - $31 million).

6. Interest, Net

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	**2009**	2008
Interest Expense - Long-Term Debt	**$ 123**	$ 144	**$ 241**	$ 284
Interest Expense - Other *	**50**	56	**89**	110
Interest Income *	**(44)**	(53)	**(97)**	(113)
	$ 129	$ 147	**$ 233**	$ 281

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

7. Foreign Exchange (Gain) Loss, Net

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada *	**$ (439)**	$ (52)	**$ (289)**	$ 165
Translation of U.S. dollar partnership contribution receivable issued from Canada *	**247**	44	**160**	(99)
Other Foreign Exchange (Gain) Loss on:				
Monetary revaluations and settlements	**132**	(27)	**127**	(6)
	$ (60)	$ (35)	**$ (2)**	$ 60

* Reflects the current year change in foreign exchange rates calculated on the period end balance.

8. Income Taxes

The provision for income taxes is as follows:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Current				
Canada	**$ 268**	$ 172	**$ 440**	$ 406
United States	**38**	256	**114**	385
Other Countries	**7**	12	**6**	13
Total Current Tax	**313**	440	**560**	804
Future	**(231)**	152	**(194)**	73
	$ 82	$ 592	**$ 366**	$ 877

9. Inventories

	As at June 30, 2009	As at December 31, 2008
Product		
Canada	**$ 57**	$ 46
USA	**5**	8
Downstream Refining	**480**	323
Market Optimization	**154**	127
Parts and Supplies	**14**	16
	$ 710	$ 520

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

10. Long-Term Debt

	As at June 30, 2009	As at December 31, 2008
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 914**	$ 1,410
Unsecured notes	**1,075**	1,020
	1,989	2,430
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**125**	247
Unsecured notes	**6,850**	6,350
	6,975	6,597
Increase in Value of Debt Acquired	**49**	49
Debt Discounts and Financing Costs	**(75)**	(71)
Current Portion of Long-Term Debt	**(250)**	(250)
	$ 8,688	$ 8,755

On May 4, 2009, EnCana completed a public offering in the United States of senior unsecured notes in the aggregate principal amount of US$500 million. The notes have a coupon rate of 6.5 percent and mature on May 15, 2019. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

11. 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, 2009	As at December 31, 2008
Asset Retirement Obligation, Beginning of Year	**$ 1,265**	$ 1,458
Liabilities Incurred	**10**	54
Liabilities Settled	**(31)**	(115)
Liabilities Divested	**-**	(38)
Change in Estimated Future Cash Flows	**(8)**	54
Accretion Expense	**36**	79
Foreign Currency Translation	**53**	(227)
Asset Retirement Obligation, End of Period	**$ 1,325**	$ 1,265

12. Share Capital

(millions)	June 30, 2009 Number	Amount	December 31, 2008 Number	Amount
Common Shares Outstanding, Beginning of Year	**750.4**	**$ 4,557**	750.2	$ 4,479
Common Shares Issued under Option Plans	**0.2**	**2**	3.0	80
Common Shares Issued from PSU Trust	**0.5**	**19**	-	-
Stock-Based Compensation	**-**	**1**	-	11
Common Shares Purchased	**-**	**-**	(2.8)	(13)
Common Shares Outstanding, End of Period	**751.1**	**$ 4,579**	750.4	$ 4,557

Performance Share Units ("PSUs")

In April, 2009, the remaining 0.5 million Common Shares held in trust relating to EnCana's PSU plan were sold for total consideration of $25 million. Of the amount received, $19 million was credited to Share capital and $6 million to Paid in surplus, representing the excess consideration received over the original price of the Common Shares acquired by the trust. Effective May 15, 2009, EnCana's PSU plan was complete and the trust ageement was terminated.

Normal Course Issuer Bid

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under seven consecutive Normal Course Issuer Bids ("Bids"). EnCana is entitled to purchase, for cancellation, up to approximately 75.0 million Common Shares under the renewed Bid which commenced on November 13, 2008 and terminates on November 12, 2009. To June 30, 2009, there have been no purchases under the current bid (2008 - 4.8 million Common Shares for approximately $326 million).

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 granted. 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 related to options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSARs") attached to them at June 30, 2009. Information related to TSARs is included in Note 14.

	Stock Options ***(millions)***	**Weighted Average Exercise Price** ***(C$)***
Outstanding, Beginning of Year	**0.5**	**11.62**
Exercised	**(0.2)**	**11.58**
Outstanding, End of Period	**0.3**	**11.79**
Exercisable, End of Period	**0.3**	**11.79**

Range of Exercise Price (C$)	**Outstanding & Exercisable Options** Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*
11.50 to 14.50	0.3	0.6	11.79

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. 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 to preserve EnCana's access to capital markets and its ability to meet its financial obligations;
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 Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward the Company's overall debt position as measures of the Company's overall financial strength.

EnCana targets a Debt to Capitalization ratio of less than 40 percent. At June 30, 2009, EnCana's Debt to Capitalization ratio was 27 percent (December 31, 2008 - 28 percent) calculated as follows:

	As at	
	June 30, 2009	December 31, 2008
Debt	**$ 8,938**	$ 9,005
Total Shareholders' Equity	**24,247**	22,974
Total Capitalization	**$ 33,185**	$ 31,979
Debt to Capitalization ratio	**27%**	28%

EnCana targets a Debt to Adjusted EBITDA of less than 2.0 times. At June 30, 2009, Debt to Adjusted EBITDA was 0.7x (December 31, 2008 - 0.7x) calculated on a trailing twelve-month basis as follows:

	As at	
	June 30, 2009	December 31, 2008
Debt	**$ 8,938**	$ 9,005
Net Earnings	**$ 5,831**	$ 5,944
Add (deduct):		
Interest, net	**538**	586
Income tax expense	**2,122**	2,633
Depreciation, depletion and amortization	**4,054**	4,223
Accretion of asset retirement obligation	**74**	79
Foreign exchange (gain) loss, net	**361**	423
(Gain) loss on divestitures	**(121)**	(140)
Adjusted EBITDA	**$ 12,859**	$ 13,748
Debt to Adjusted EBITDA	**0.7x**	0.7x

EnCana has a long-standing practice of maintaining capital discipline, managing its capital structure and adjusting its capital structure 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 and definitions 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)

14. Compensation Plans

The following tables outline certain information related to EnCana's compensation plans at June 30, 2009. Additional information is contained in Note 19 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2008.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	**2009**	2008
Current Service Cost	**$ 3**	$ 4	**$ 7**	$ 8
Interest Cost	**5**	6	**10**	11
Expected Return on Plan Assets	**(3)**	(5)	**(7)**	(10)
Amortization of Net Actuarial Losses	**2**	1	**4**	2
Amortization of Past Service Costs	**-**	-	**1**	1
Amortization of Transitional Obligation	**1**	-	**1**	(1)
Expense for Defined Contribution Plan	**11**	10	**22**	20
Net Benefit Plan Expense	**$ 19**	$ 16	**$ 38**	$ 31

For the six months ended June 30, 2009, contributions of $3 million have been made to the defined benefit pension plans (2008 - $7 million).

B) Tandem Share Appreciation Rights ("TSARs")

The following table summarizes information related to the TSARs at June 30, 2009:

	Outstanding TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**19,411,939**	**53.97**
Granted	**3,937,960**	**55.33**
Exercised - SARs	**(1,457,058)**	**42.20**
Exercised - Options	**(45,264)**	**33.97**
Forfeited	**(257,684)**	**59.12**
Outstanding, End of Period	**21,589,893**	**55.00**
Exercisable, End of Period	**12,544,910**	**50.64**

For the period ended June 30, 2009, EnCana recorded compensation costs of $32 million related to the outstanding TSARs (2008 - $340 million).

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

The following table summarizes information related to the Performance TSARs at June 30, 2009:

	Outstanding Performance TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**12,979,725**	**63.13**
Granted	**7,751,720**	**55.31**
Exercised - SARs	**(99,163)**	**56.09**
Exercised - Options	**(765)**	**56.09**
Forfeited	**(1,768,602)**	**62.87**
Outstanding, End of Period	**18,862,915**	**59.98**
Exercisable, End of Period	**3,839,884**	**60.46**

For the period ended June 30, 2009, EnCana recorded compensation costs of $14 million related to the outstanding Performance TSARs (2008 - $126 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. Compensation Plans (continued)

D) Share Appreciation Rights ("SARs")

The following table summarizes information related to the SARs at June 30, 2009:

	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**1,285,065**	**72.13**
Granted	**1,112,020**	**55.41**
Forfeited	**(37,205)**	**68.14**
Outstanding, End of Period	**2,359,880**	**64.31**
Exercisable, End of Period	**281,758**	**72.33**

For the period ended June 30, 2009, EnCana has recorded compensation costs of $1 million related to the outstanding SARs (2008 - $5 million).

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

The following table summarizes information related to the Performance SARs at June 30, 2009:

	Outstanding Performance SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**1,620,930**	**69.40**
Granted	**2,140,440**	**55.31**
Forfeited	**(221,323)**	**68.62**
Outstanding, End of Period	**3,540,047**	**60.93**
Exercisable, End of Period	**298,663**	**69.40**

For the period ended June 30, 2009, EnCana has recorded compensation costs of $1 million related to the outstanding Performance SARs (2008 - $4 million).

F) Deferred Share Units ("DSUs")

The following table summarizes information related to the DSUs at June 30, 2009:

	Outstanding DSUs
Canadian Dollar Denominated	
Outstanding, Beginning of Year	**656,841**
Granted	**72,808**
Converted from HPR awards	**46,884**
Units, in Lieu of Dividends	**13,434**
Redeemed	**(45,352)**
Outstanding, End of Period	**744,615**

For the period ended June 30, 2009, EnCana has recorded compensation costs of $5 million related to the outstanding DSUs (2008 - $23 million).

In 2009, employees had the option to convert either 25 or 50 percent of their annual High Performance Results ("HPR") award into DSUs. The number of DSUs is based on the value of the award divided by the closing value of EnCana's share price at the end of the performance period of the HPR award. DSUs vest immediately, can be redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of termination.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

15. 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)	2009	**2009**	2008	**2009**	2008
Weighted Average Common Shares Outstanding - Basic	750.5	**751.0**	750.2	**750.8**	749.8
Effect of Dilutive Securities	0.9	**0.4**	1.1	**0.6**	2.5
Weighted Average Common Shares Outstanding - Diluted	751.4	**751.4**	751.3	**751.4**	752.3

16. 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.

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 11 to the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2008.

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 value of financial assets and liabilities were as follows:

	As at June 30, 2009		As at December 31, 2008	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Held-for-Trading:				
Cash and cash equivalents	**$ 330**	**$ 330**	$ 383	$ 383
Risk management assets *	**1,971**	**1,971**	3,052	3,052
Loans and Receivables:				
Accounts receivable and accrued revenues	**1,472**	**1,472**	1,568	1,568
Partnership contribution receivable *	**2,993**	**2,993**	3,147	3,147
Financial Liabilities				
Held-for-Trading:				
Risk management liabilities *	**$ 40**	**$ 40**	$ 50	$ 50
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**2,401**	**2,401**	2,871	2,871
Long-term debt *	**8,938**	**9,349**	9,005	8,242
Partnership contribution payable *	**3,012**	**3,012**	3,163	3,163

* Including current portion.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities

Net Risk Management Position	As at June 30, 2009	As at December 31, 2008
Risk Management		
Current asset	$ 1,927	$ 2,818
Long-term asset	44	234
	1,971	3,052
Risk Management		
Current liability	14	43
Long-term liability	26	7
	40	50
Net Risk Management Asset (Liability)	$ 1,931	$ 3,002

Summary of Unrealized Risk Management Positions

	As at June 30, 2009			As at December 31, 2008		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Natural gas	$ 1,952	$ 27	$ 1,925	$ 2,941	$ 10	$ 2,931
Crude oil	13	13	-	92	40	52
Power	6	-	6	19	-	19
Total Fair Value	$ 1,971	$ 40	$ 1,931	$ 3,052	$ 50	$ 3,002

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

	As at June 30, 2009	As at December 31, 2008
Prices actively quoted	$ 1,501	$ 2,055
Prices sourced from observable data or market corroboration	430	947
Total Fair Value	$ 1,931	$ 3,002

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.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities (continued)

Net Fair Value of Commodity Price Positions at June 30, 2009

	Notional Volumes		Term	Average Price		Fair Value
Natural Gas Contracts						
Fixed Price Contracts						
NYMEX Fixed Price	1,897	MMcf/d	2009	8.35	US$/Mcf	$ 1,388
NYMEX Fixed Price	1,415	MMcf/d	2010	6.13	US$/Mcf	112
Purchased Options						
NYMEX Call	(120)	MMcf/d	2009	11.67	US$/Mcf	(10)
NYMEX Put	414	MMcf/d	2009	9.10	US$/Mcf	355
Basis Contracts						
Canada	80	MMcf/d	2009			6
United States	373	MMcf/d	2009			(3)
Canada and United States *			2010-2013			31
						1,879
Other Financial Positions **						1
Total Unrealized Gain on Financial Contracts						1,880
Premiums Paid on Unexpired Options						45
Natural Gas Fair Value Position						$ 1,925

* 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 management.

	Notional Volumes		Term	Average Price		Fair Value
Crude Oil Contracts						
Fixed Price Contracts						
WTI NYMEX Fixed Price	19,000	bbls/d	2010	76.46	US$/bbl	$ 8
Other Financial Positions *						(8)
Crude Oil Fair Value Position						$ -

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

	Fair Value
Power Purchase Contracts	
Power Fair Value Position	$ 6

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities (continued)

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,	
	2009	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,345**	$ (586)	**$ 2,414**	$ (566)
Operating Expenses and Other	**(5)**	(2)	**(29)**	-
Gain (Loss) on Risk Management	**$ 1,340**	$ (588)	**$ 2,385**	$ (566)

	Unrealized Gain (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	**2009**	2008
Revenues, Net of Royalties	**$ (1,114)**	$ (328)	**$ (981)**	$ (1,424)
Operating Expenses and Other	**(4)**	10	**(26)**	13
Gain (Loss) on Risk Management	**$ (1,118)**	$ (318)	**$ (1,007)**	$ (1,411)

Reconciliation of Unrealized Risk Management Positions from January 1 to June 30, 2009

	2009		2008
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 2,892**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**1,378**	**$ 1,378**	$ (1,977)
Foreign Exchange Gain (Loss) on Canadian Dollar Contracts	**1**	**-**	-
Fair Value of Contracts Realized During the Period	**(2,385)**	**(2,385)**	566
Fair Value of Contracts Outstanding	**$ 1,886**	**$ (1,007)**	$ (1,411)
Premiums Paid on Unexpired Options	**45**		
Fair Value of Contracts and Premiums Paid, End of Period	**$ 1,931**		

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. The Company has used a 10% variability to assess the potential impact of commodity price changes. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting net earnings as at June 30, 2009 as follows:

	10% Price Increase	10% Price Decrease
Natural gas price	$ (469)	$ 469
Crude oil price	(57)	57
Power price	10	(10)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. Financial Instruments and Risk Management (continued)

C) Risks Associated with Financial Assets and Liabilities

The Company is exposed to financial risks arising from its financial assets and liabilities. Financial risks include market risks (such as commodity prices, foreign exchange and interest rates), credit risk and liquidity risk. The fair value or future cash flows of financial assets or liabilities may fluctuate due to movement in market prices and the exposure to credit and liquidity risks.

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is to not use derivative financial instruments for speculative purposes.

Natural Gas - To partially mitigate the natural gas commodity price risk, the Company has entered 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 commodity price risk on crude oil and condensate supply with swaps which fix WTI NYMEX prices.

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.

Credit Risk

Credit risk arises from the potential the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk 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. Any foreign currency agreements entered into 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. As at June 30, 2009, approximately 94 percent of EnCana's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At June 30, 2009, 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 a demand to fund its financial liabilities as they come due. The Company manages its liquidity risk through cash and debt management. As disclosed in Note 13, EnCana targets a Debt to Capitalization ratio between 30 and 40 percent and a 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, 2009, EnCana had available unused committed bank credit facilities in the amount of $3.4 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for $5.2 billion. The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. Financial Instruments and Risk Management (continued)

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

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor's Ratings Services has assigned a rating of "A-" with a "Negative" outlook, Moody's Investors Service has assigned a rating of "Baa2" with a "Stable" outlook and DBRS Limited has assigned a rating of "A (low)" and placed the rating "Under Review with Developing Implications". DBRS Limited placed the rating "Under Review" following the May 11, 2008 announcement of the proposed corporate reorganization.

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

	Less Than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	$ 2,401	$ -	$ -	$ -	$ 2,401
Risk Management Liabilities	14	26	-	-	40
Long-Term Debt *	736	2,046	3,341	9,924	16,047
Partnership Contribution Payable *	489	978	978	1,344	3,789

* Principal and interest, including current portion.

Included in EnCana's total long-term debt obligations of $16,047 million at June 30, 2009 are $1,039 million in principal obligations related to Commercial Paper. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 - 5 Years. Further information on Long-term Debt is contained in Note 10.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. 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 7, 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 the U.S. dollar partnership contribution receivable issued from Canada. At June 30, 2009, EnCana had $5,850 million in U.S. dollar debt issued from Canada ($5,350 million at December 31, 2008) and $2,993 million related to the U.S. dollar partnership contribution receivable ($3,147 million at December 31, 2008). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $25 million change in foreign exchange (gain) loss at June 30, 2009 (2008 - $21 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At June 30, 2009, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $7 million (2008 - $16 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. 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. All but one of these lawsuits has been settled prior to 2009, without admitting any liability in the lawsuits.

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.

18. Reclassification

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2009.

Supplemental Financial Information *(unaudited)*

Financial Statistics

($ millions, except per share amounts)		2009			2008			
	Year-to-date	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Consolidated								
Cash Flow (1)	**4,097**	**2,153**	1,944	9,386	1,299	2,809	2,889	2,389
Per share - Basic	**5.46**	**2.87**	2.59	12.51	1.73	3.74	3.85	3.19
- Diluted	**5.45**	**2.87**	2.59	12.48	1.73	3.74	3.85	3.17
Net Earnings	**1,201**	**239**	962	5,944	1,077	3,553	1,221	93
Per share - Basic	**1.60**	**0.32**	1.28	7.92	1.44	4.74	1.63	0.12
- Diluted	**1.60**	**0.32**	1.28	7.91	1.43	4.73	1.63	0.12
Operating Earnings (2)	**1,865**	**917**	948	4,405	449	1,442	1,469	1,045
Per share - Diluted	**2.48**	**1.22**	1.26	5.86	0.60	1.92	1.96	1.39
Effective Tax Rates using								
Net Earnings	**23.4%**			30.7%				
Operating Earnings, excluding divestitures	**25.5%**			28.0%				
Canadian Statutory Rate	**29.2%**			29.7%				
Foreign Exchange Rates *(US$ per C$1)*								
Average	**0.829**	**0.857**	0.803	0.938	0.825	0.961	0.990	0.996
Period end	**0.860**	**0.860**	0.794	0.817	0.817	0.944	0.982	0.973
Cash Flow Information								
Cash from Operating Activities	**3,786**	**1,955**	1,831	8,855	2,043	3,058	1,996	1,758
Deduct (Add back):								
Net change in other assets and liabilities	**23**	**9**	14	(262)	21	(19)	(171)	(93)
Net change in non-cash working capital	**(334)**	**(207)**	(127)	(269)	723	268	(722)	(538)
Cash Flow (1)	**4,097**	**2,153**	1,944	9,386	1,299	2,809	2,889	2,389

(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.

	2009	2008
Financial Metrics		
Debt to Capitalization (1)	**27%**	28%
Debt to Adjusted EBITDA (1, 2)	**0.7x**	0.7x
Return on Capital Employed (1, 2)	**19%**	20%
Return on Common Equity (2)	**26%**	27%

(1) Calculated using Debt defined as the current and long-term portions of Long-Term Debt.
(2) Calculated on a trailing twelve-month basis.

Supplemental Financial Information *(unaudited)*

Financial Statistics (continued)

($ millions, except per share amounts)

Common Share Information	**2009**			2008				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*								
Period end	**751.1**	**751.1**	750.6	750.4	750.4	750.3	750.2	750.0
Average - Basic	**750.8**	**751.0**	750.5	750.1	750.3	750.3	750.2	749.5
Average - Diluted	**751.4**	**751.4**	751.4	751.8	751.3	751.3	751.3	753.0
Price Range *($ per share)*								
TSX - C$								
High	**65.71**	**65.71**	63.50	97.81	68.04	95.91	97.81	79.26
Low	**44.64**	**50.33**	44.64	41.36	41.36	63.84	76.41	59.95
Close	**57.67**	**57.67**	51.60	56.96	56.96	67.96	93.36	78.20
NYSE - US$								
High	**58.34**	**58.34**	53.81	99.36	64.19	94.41	99.36	79.75
Low	**35.46**	**39.70**	35.46	34.00	34.00	61.13	74.16	58.13
Close	**49.47**	**49.47**	40.61	46.48	46.48	65.73	90.93	75.75
Dividends Paid *($ per share)*	**0.80**	**0.40**	0.40	1.60	0.40	0.40	0.40	0.40
Share Volume Traded *(millions)*	**765.5**	**323.8**	441.7	1,893.7	614.9	547.7	376.4	354.7
Share Value Traded *(US$ millions weekly average)*	**1,355.3**	**1,248.1**	1,495.5	2,348.6	2,114.5	2,912.5	2,486.0	1,900.5

Net Capital Investment *($ millions, for the six months ended June 30)*	**2009**	2008
Capital Investment		
Canada		
Canadian Plains	**$ 228**	$ 420
Canadian Foothills	**745**	1,363
Integrated Oil - Canada	**229**	352
USA	**925**	1,179
Downstream Refining	**429**	177
Market Optimization	**(3)**	7
Corporate & Other	**33**	69
Capital Investment	**2,586**	3,567
Acquisitions		
Property		
Canada		
Canadian Plains	**1**	-
Canadian Foothills	**74**	92
USA	**14**	244
Corporate		
Canada		
Canadian Foothills [(1)]	**24**	-
Divestitures		
Property		
Canada		
Canadian Plains	**-**	(31)
Canadian Foothills	**(44)**	(70)
Integrated Oil - Canada	**-**	(8)
USA	**(4)**	(95)
Corporate & Other	**(5)**	53
Net Acquisition and Divestiture Activity	**60**	185
Net Capital Investment	**$ 2,646**	$ 3,752

[(1)] Acquisition of Kerogen Resources Canada, ULC on May 5, 2009.

Supplemental Financial Information *(unaudited)*

Operating Statistics - After Royalties

Production Volumes by Geographic Region	**2009**			2008				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*								
Canada	**2,165**	**2,207**	2,123	2,205	2,181	2,243	2,212	2,181
USA	**1,663**	**1,581**	1,746	1,633	1,677	1,674	1,629	1,552
	3,828	**3,788**	3,869	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids [(1)] *(bbls/d)*								
Canada	**123,284**	**123,954**	122,609	120,230	123,019	119,703	114,121	124,056
USA	**11,685**	**11,699**	11,671	13,350	12,831	13,853	13,482	13,232
	134,969	**135,653**	134,280	133,580	135,850	133,556	127,603	137,288
Total *(MMcfe/d)*								
Canada	**2,905**	**2,951**	2,859	2,926	2,919	2,961	2,897	2,926
USA	**1,733**	**1,651**	1,816	1,713	1,754	1,757	1,710	1,631
	4,638	**4,602**	4,675	4,639	4,673	4,718	4,607	4,557

(1) Natural gas liquids include condensate volumes.

Production Volumes	**2009**			2008				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*								
Canadian Plains	**796**	**792**	800	842	820	831	856	860
Canadian Foothills	**1,312**	**1,343**	1,281	1,300	1,302	1,351	1,289	1,256
USA	**1,663**	**1,581**	1,746	1,633	1,677	1,674	1,629	1,552
Integrated Oil - Other	**57**	**72**	42	63	59	61	67	65
Total Produced Gas	**3,828**	**3,788**	3,869	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids *(bbls/d)*								
Light and Medium Oil								
Canadian Plains	**31,562**	**31,183**	31,946	31,128	32,147	30,134	30,479	31,752
Canadian Foothills	**7,969**	**7,800**	8,140	8,473	8,437	8,217	8,376	8,867
Heavy Oil								
Canadian Plains	**33,293**	**31,508**	35,097	35,029	32,843	34,655	34,618	38,029
Integrated Oil - Foster Creek/Christina Lake	**37,720**	**40,677**	34,729	30,183	35,068	31,547	24,671	29,376
Integrated Oil - Other	**1,933**	**1,800**	2,069	2,729	2,133	2,273	3,009	3,514
Natural Gas Liquids [(1)]								
Canadian Plains	**1,181**	**1,162**	1,201	1,181	1,126	1,147	1,189	1,262
Canadian Foothills	**9,626**	**9,824**	9,427	11,507	11,265	11,730	11,779	11,256
USA	**11,685**	**11,699**	11,671	13,350	12,831	13,853	13,482	13,232
Total Oil and Natural Gas Liquids	**134,969**	**135,653**	134,280	133,580	135,850	133,556	127,603	137,288
Total *(MMcfe/d)*	**4,638**	**4,602**	4,675	4,639	4,673	4,718	4,607	4,557

(1) Natural gas liquids include condensate volumes.

Downstream Refining	**2009**			2008				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations [(1)]								
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**401**	**404**	398	423	434	412	437	408
Crude utilization *(%)*	**89%**	**89%**	88%	93%	96%	91%	97%	90%
Refined products *(Mbbls/d)*	**425**	**428**	421	448	456	438	464	435

(1) 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)

	2009			2008				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas - Canadian Plains *($/Mcf)*								
Price	**3.83**	**3.23**	4.42	7.77	5.65	8.67	9.50	7.19
Production and mineral taxes	**0.06**	**0.07**	0.05	0.12	0.06	0.17	0.17	0.06
Transportation and selling	**0.14**	**0.14**	0.15	0.23	0.21	0.24	0.22	0.25
Operating	**0.71**	**0.71**	0.71	0.78	0.65	0.59	0.96	0.93
Netback	**2.92**	**2.31**	3.51	6.64	4.73	7.67	8.15	5.95
Produced Gas - Canadian Foothills *($/Mcf)*								
Price	**3.86**	**3.19**	4.58	8.12	5.87	9.03	9.94	7.61
Production and mineral taxes	**0.04**	**0.04**	0.03	0.06	0.03	0.09	0.09	0.03
Transportation and selling	**0.30**	**0.30**	0.30	0.42	0.37	0.43	0.43	0.47
Operating	**1.03**	**1.02**	1.04	1.15	0.98	0.87	1.39	1.41
Netback	**2.49**	**1.83**	3.21	6.49	4.49	7.64	8.03	5.70
Produced Gas - Canada *($/Mcf)*								
Price	**3.84**	**3.20**	4.51	7.97	5.78	8.88	9.76	7.44
Production and mineral taxes	**0.04**	**0.05**	0.04	0.08	0.04	0.12	0.12	0.04
Transportation and selling	**0.24**	**0.23**	0.24	0.35	0.31	0.36	0.35	0.38
Operating	**0.92**	**0.89**	0.94	1.03	0.87	0.77	1.23	1.25
Netback	**2.64**	**2.03**	3.29	6.51	4.56	7.63	8.06	5.77
Produced Gas - USA *($/Mcf)*								
Price	**3.46**	**3.01**	3.88	7.89	5.01	8.54	9.93	8.19
Production and mineral taxes	**0.18**	**0.08**	0.27	0.56	0.35	0.56	0.72	0.62
Transportation and selling	**0.82**	**0.87**	0.78	0.84	0.87	0.86	0.81	0.81
Operating	**0.53**	**0.54**	0.51	0.59	0.56	0.38	0.71	0.71
Netback	**1.93**	**1.52**	2.32	5.90	3.23	6.74	7.69	6.05
Produced Gas - Total *($/Mcf)*								
Price	**3.68**	**3.12**	4.23	7.94	5.44	8.74	9.83	7.75
Production and mineral taxes	**0.10**	**0.06**	0.14	0.28	0.17	0.31	0.37	0.28
Transportation and selling	**0.49**	**0.50**	0.49	0.56	0.55	0.57	0.55	0.56
Operating	**0.75**	**0.75**	0.75	0.84	0.74	0.61	1.01	1.02
Netback	**2.34**	**1.81**	2.85	6.26	3.98	7.25	7.90	5.89
Natural Gas Liquids - Canadian Plains *($/bbl)*								
Price	**36.59**	**38.36**	34.86	78.91	45.13	98.35	96.34	75.09
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**-**	**-**	-	-	-	0.01	-	-
Netback	**36.59**	**38.36**	34.86	78.91	45.13	98.34	96.34	75.09
Natural Gas Liquids - Canadian Foothills *($/bbl)*								
Price	**38.00**	**40.07**	35.81	80.22	42.03	95.49	101.23	80.80
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**1.45**	**1.70**	1.19	1.33	1.33	1.20	1.73	1.04
Netback	**36.55**	**38.37**	34.62	78.89	40.70	94.29	99.50	79.76
Natural Gas Liquids - Canada *($/bbl)*								
Price	**37.84**	**39.89**	35.70	80.10	42.31	95.74	100.78	80.23
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**1.29**	**1.52**	1.06	1.21	1.21	1.10	1.57	0.94
Netback	**36.55**	**38.37**	34.64	78.89	41.10	94.64	99.21	79.29
Natural Gas Liquids - USA [(1)] *($/bbl)*								
Price	**37.42**	**47.27**	27.43	83.18	45.39	97.63	105.73	82.22
Production and mineral taxes	**3.33**	**4.18**	2.48	7.25	3.79	8.19	9.75	7.13
Transportation and selling	**-**	**-**	-	-	-	-	-	-
Netback	**34.09**	**43.09**	24.95	75.93	41.60	89.44	95.98	75.09
Natural Gas Liquids - Total *($/bbl)*								
Price	**37.62**	**43.70**	31.37	81.67	43.88	96.72	103.29	81.24
Production and mineral taxes	**1.73**	**2.16**	1.30	3.70	1.93	4.25	4.94	3.63
Transportation and selling	**0.62**	**0.74**	0.51	0.59	0.59	0.53	0.78	0.46
Netback	**35.27**	**40.80**	29.56	77.38	41.36	91.94	97.57	77.15
Crude Oil - Light and Medium - Canadian Plains *($/bbl)*								
Price	**46.24**	**55.00**	37.51	84.84	41.60	107.59	107.08	85.90
Production and mineral taxes	**2.28**	**1.86**	2.69	3.33	2.05	4.70	3.97	2.72
Transportation and selling	**0.99**	**1.02**	0.96	1.20	0.96	1.41	1.27	1.16
Operating	**9.42**	**9.35**	9.50	10.56	8.28	9.40	13.05	11.60
Netback	**33.55**	**42.77**	24.36	69.75	30.31	92.08	88.79	70.42

(1) The Natural Gas Liquids - USA netback is equivalent to the Total Liquids - USA netback.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2009			2008				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil - Light and Medium - Canadian Foothills *($/bbl)*								
Price	**45.13**	**53.10**	37.31	91.78	47.51	112.73	114.28	93.42
Production and mineral taxes	**1.04**	**1.06**	1.02	1.48	1.11	1.65	2.05	1.16
Transportation and selling	**0.70**	**(0.72)**	2.09	2.07	1.55	2.12	2.70	1.92
Operating	**8.86**	**9.21**	8.52	12.75	11.68	10.02	15.39	13.84
Netback	**34.53**	**43.55**	25.68	75.48	33.17	98.94	94.14	76.50
Crude Oil - Heavy - Canadian Plains *($/bbl)*								
Price	**39.72**	**48.22**	31.34	74.08	31.30	95.86	98.65	70.44
Production and mineral taxes	**(0.02)**	**0.02**	(0.07)	0.03	0.06	0.07	(0.10)	0.07
Transportation and selling	**1.27**	**1.37**	1.17	1.60	1.13	2.42	1.60	1.29
Operating	**8.71**	**9.61**	7.82	9.04	7.17	7.62	11.30	9.93
Netback	**29.76**	**37.22**	22.42	63.41	22.94	85.75	85.85	59.15
Crude Oil - Total - excluding Foster Creek/Christina Lake *($/bbl)*								
Price	**43.09**	**51.80**	34.49	80.31	37.20	102.66	103.40	78.82
Production and mineral taxes	**1.09**	**0.96**	1.22	1.56	1.02	2.16	1.81	1.28
Transportation and selling	**1.13**	**1.04**	1.21	1.52	1.13	2.00	1.61	1.36
Operating	**9.30**	**9.78**	8.83	10.43	8.28	8.99	13.00	11.39
Netback	**31.57**	**40.02**	23.23	66.80	26.77	89.51	86.98	64.79
Crude Oil - Heavy - Foster Creek/Christina Lake *($/bbl)*								
Price (1)	**38.16**	**47.34**	26.90	62.44	19.86	91.21	93.64	59.67
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**2.64**	**2.93**	2.29	2.36	2.04	2.10	2.77	2.72
Operating	**11.76**	**10.51**	13.28	15.53	10.73	15.53	21.41	16.62
Netback	**23.76**	**33.90**	11.33	44.55	7.09	73.58	69.46	40.33
Crude Oil - Total (2) *($/bbl)*								
Price	**41.46**	**50.22**	32.16	75.36	31.58	99.39	100.99	74.10
Production and mineral taxes	**0.73**	**0.62**	0.84	1.13	0.69	1.54	1.36	0.96
Transportation and selling	**1.63**	**1.71**	1.54	1.75	1.43	2.03	1.90	1.69
Operating	**10.12**	**10.04**	10.19	11.84	9.08	10.86	15.08	12.68
Netback	**28.98**	**37.85**	19.59	60.64	20.38	84.96	82.65	58.77
Total Liquids - Canada *($/bbl)*								
Price	**41.14**	**49.31**	32.48	75.85	32.63	98.99	100.97	74.69
Production and mineral taxes	**0.66**	**0.57**	0.77	1.01	0.62	1.37	1.20	0.86
Transportation and selling	**1.60**	**1.69**	1.50	1.70	1.41	1.93	1.86	1.62
Operating	**9.22**	**9.16**	9.29	10.57	8.19	9.68	13.34	11.30
Netback	**29.66**	**37.89**	20.92	62.57	22.41	86.01	84.57	60.91
Total Liquids *($/bbl)*								
Price	**40.81**	**49.14**	32.03	76.58	33.81	98.85	101.46	75.44
Production and mineral taxes	**0.90**	**0.88**	0.92	1.63	0.92	2.09	2.09	1.46
Transportation and selling	**1.46**	**1.55**	1.36	1.53	1.28	1.72	1.67	1.46
Operating	**8.42**	**8.38**	8.46	9.55	7.43	8.66	12.00	10.30
Netback	**30.03**	**38.33**	21.29	63.87	24.18	86.38	85.70	62.22
Total *($/Mcfe)*								
Price	**4.22**	**4.02**	4.42	8.77	5.48	10.04	11.02	8.61
Production and mineral taxes	**0.11**	**0.08**	0.15	0.28	0.17	0.32	0.37	0.28
Transportation and selling	**0.45**	**0.46**	0.44	0.50	0.49	0.53	0.50	0.50
Operating (3)	**0.86**	**0.86**	0.86	0.97	0.83	0.75	1.17	1.15
Netback	**2.80**	**2.62**	2.97	7.02	3.99	8.44	8.98	6.68

(1) 2008 price includes the impact of the write-down of condensate inventories to net realizable value (2008 - $4.26/bbl; Q4 2008 - $11.21/bbl; Q3 2008 - $3.07/bbl).

(2) The Crude Oil - Total netback is equivalent to the Crude Oil - Canada netback.

(3) 2009 year-to-date operating costs include costs related to long-term incentives of $0.01/Mcfe (2008 - $0.15/Mcfe).

Impact of Realized Financial Hedging

Natural Gas *($/Mcf)*	**3.43**	**3.87**	2.99	(0.02)	1.74	(0.80)	(1.29)	0.27
Liquids *($/bbl)*	**1.64**	**1.09**	2.21	(5.46)	2.35	(7.97)	(10.99)	(5.85)
Total *($/Mcfe)*	**2.88**	**3.21**	2.55	(0.17)	1.50	(0.89)	(1.38)	0.05

EnCana Corporation

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