EnCana's second quarter cash flow exceeds US$2.5 billion, or $3.33 per share – up 55 percent

Raising full year cash flow guidance to between $10.20 and $10.70 per share

Natural gas production increases 4 percent to 3.5 billion cubic feet per day

Calgary, Alberta, (July 25, 2007) – Solid natural gas and oilsands production growth, stronger realized gas prices and robust refining margins all contributed to substantial increases in EnCana Corporation's (TSX & NYSE: ECA) cash flow and operating earnings in the second quarter of 2007.

"Now transformed into a leading integrated producer of North American unconventional natural gas and in-situ oilsands, our company is hitting its stride. Our diverse portfolio of natural gas, oil and oilsands resource plays and our interests in two refineries are generating strong financial and operating performance. Second quarter cash flow and operating earnings are significantly higher than one year ago, production is on track to meet our full-year targets and capital costs are tracking below budget at mid-year. Our sustainable low-risk business model is delivering on our expectations and we are well positioned to create strong, long-term performance," said Randy Eresman, EnCana's President & Chief Executive Officer.

"Based on our expectations for the remainder of the year and the strong cash flow performance to date from our upstream operations and the larger-than-expected contributions from our integrated oilsands business, we are raising our annual guidance for total cash flow to a range of $7.8 billion to $8.2 billion. Also, having already completed a significant portion of our planned share purchase program, cash flow per share guidance is now between $10.20 and $10.70, representing a forecast growth range of 19 to 25 percent compared to 2006," Eresman said.

Second Quarter 2007 Highlights

(all comparisons are to the second quarter of 2006)

Financial – US$

- Cash flow per share diluted increased 55 percent to $3.33, or $2.55 billion (includes $0.17 billion, or 23 cents per share, of tax recoveries due to legislative changes)
- Operating earnings per share diluted up 84 percent to $1.80, or $1.38 billion (includes $0.23 billion, or 30 cents per share, of tax recoveries due to legislative changes)
- Net earnings per share diluted down 26 percent to $1.89, or $1.45 billion (in the second quarter of 2006 EnCana recorded about $1.3 billion of non-operating gains, or $1.57 per share)
- Integrated oilsands business generated $500 million of operating cash flow
- Core capital investment in continuing operations down 28 percent to $1.17 billion
- Generated $1.38 billion of free cash flow (as defined in Note 1 on page 7)
- Purchased approximately 12 million EnCana shares at an average price of $59.23 under the Normal Course Issuer Bid

Operating – Upstream

- Natural gas production increased 4 percent to 3.51 billion cubic feet per day (Bcf/d), up 14 percent per share
- Oil and natural gas liquids (NGLs) production up 1 percent on a pro forma basis to more than 133,000 barrels per day (bbls/d), up 10 percent per share (see pro forma note 1, Production & Drilling Summary, pg. 3)
- Total natural gas and liquids production increased 4 percent on a pro forma basis to 4.31 billion cubic feet of gas equivalent per day (Bcfe/d), up 13 percent per share
- Key natural gas resource play production up 12 percent
- Grew gross integrated oilsands production 43 percent to 56,000 bbls/d (28,000 bbls/d net to EnCana) at Foster Creek and Christina Lake
- Operating and administrative costs of $1.17 per thousand cubic feet equivalent (Mcfe) in line with guidance; an increase of 14 cents per Mcfe compared to one year earlier, made up of 8 cents due to increased long term compensation costs resulting from a higher EnCana share price, 2 cents due to foreign exchange and 4 cents due to inflation, energy and other activity-related costs

Operating – Downstream

- Refined products production averaged 421,000 bbls/d (210,500 bbls/d net to EnCana)
- Refinery crude utilization of 88 percent is lower than the first quarter of 2007 due to the planned turnaround and coker startup at the Borger refinery. Year-to-date utilization is above expectations at 92 percent largely due to a strong utilization rate of 100 percent at the Wood River refinery.
- New 25,000 bbls/d Borger coker is operating well and is processing Canadian heavy oil blended from bitumen

Natural gas production on track with 2007 forecast

Natural gas production in the second quarter rose steadily with strong year-over-year increases in a number of key resource plays – 49 percent in East Texas, 37 percent in coalbed methane (CBM) and 31 percent in Cutbank Ridge. EnCana's second largest resource play, Jonah, increased production 16 percent compared to one year ago. Gas production is currently about 3.5 Bcf/d, on track to achieve full-year guidance of 3.46 Bcf/d.

Integrated oilsands business has a strong start in 2007

The financial performance of EnCana's emerging integrated oilsands business has been well above expectations to date, largely due to stronger than anticipated refining margins. The second quarter U.S. Gulf Coast 3-2-1 crack spread averaged more than $24 per barrel, with the May average peaking above $28 per barrel. Second quarter operating cash flow from the integrated oilsands business was $500 million.

During the first quarter of 2007, the integrated oilsands business delivered about 9 percent of EnCana's total operating cash flow. After six months, that share has increased to about 14 percent, a notable rise to $661 million, which is more than the company's original full-year forecast of between $550 million and $650 million. As a result, EnCana has increased its 2007 guidance for integrated oilsands operating cash flow to $1.1 billion. Updated guidance is posted on the company's website www.encana.com.

"Our shareholders have benefited from refinery margins that are well above historical levels. While those margins are expected to soften in the latter half of 2007 following the end of the summer driving season, they are likely to stay strong for the foreseeable future due to limited spare refining capacity, continued strong transportation fuels demand and a stable economy. The financial performance of our integrated oilsands business in this, its inaugural year, has exceeded our expectations and the operating performance is tracking well against our objectives and targets – a great start to our newly created partnership with ConocoPhillips," Eresman said.

<u>IMPORTANT NOTE</u>: EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report production, sales and reserves on an after-royalties basis. The company's financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP).

Financial Summary – Total Consolidated

(for the period ended June 30) ($ millions, except per share amounts)	**Q2 2007**	Q2 2006	% Δ	**6 months 2007**	6 months 2006	% Δ
Cash flow[1]	**2,549**	1,815	+ 40	**4,301**	3,506	+ 23
Per share diluted	**3.33**	2.15	+ 55	**5.56**	4.10	+ 36
Operating earnings[1]	**1,376**	824	+ 67	**2,234**	1,518	+ 47
Per share diluted	**1.80**	0.98	+ 84	**2.89**	1.77	+ 63
Net earnings	**1,446**	2,157	- 33	**1,943**	3,631	- 46
Per share diluted	**1.89**	2.55	- 26	**2.51**	4.24	- 41
Core capital investment from continuing operations	**1,172**	1,632	- 28	**2,655**	3,578	- 26
Earnings Reconciliation Summary – Total Consolidated						
Net earnings from continuing operations	**1,446**	1,593	- 9	**1,943**	3,065	- 37
Net earnings from discontinued operations	**-**	564	n/a	**-**	566	n/a
Net earnings (loss)	**1,446**	2,157	- 33	**1,943**	3,631	- 46
(Add back losses & deduct gains)						
Unrealized mark-to-market hedging gain (loss), after-tax	**47**	160	n/a	**(376)**	990	n/a
Unrealized foreign exchange gain (loss) on translation of U.S. dollar Notes issued from Canada, after-tax	**(14)**	134	n/a	**(11)**	131	n/a
Future tax recovery due to Canada and Alberta tax rates reductions	**37**	457	n/a	**37**	457	n/a
Gain on discontinuance, after-tax	**-**	582	n/a	**59**	535	n/a
Operating earnings[1]	**1,376**	824	+ 67	**2,234**	1,518	+ 47
Per share diluted	**1.80**	0.98	+ 84	**2.89**	1.77	+ 63

1 Cash flow and Operating earnings are non-GAAP measures as defined in Note 1 on page 7.

Production & Drilling Summary

Total Consolidated

(for the period ended June 30) (After royalties)	**Q2 2007**	Q2 2006[1]	% Δ	**6 months 2007**	6 months 2006[1]	% Δ
Natural Gas (MMcf/d)	**3,506**	3,361	+ 4	**3,454**	3,352	+ 3
Natural gas production per 1,000 shares (Mcf)	**421**	369	+ 14	**819**	723	+ 13
Oil and NGLs (Mbbls/d)	**133**	132	+ 1	**132**	163	- 19
Oil and NGLs production per 1,000 shares (Mcfe)	**96**	87	+ 10	**188**	211	- 11
Total Production (MMcfe/d)	**4,306**	4,154	+ 4	**4,246**	4,328	- 2
Total per 1,000 shares (Mcfe)	**517**	456	+ 13	**1,007**	934	+ 8
Net wells drilled	**569**	558	+ 2	**1,833**	1,836	-

1 2006 information has been adjusted on a pro forma basis to reflect the integrated oilsands transaction; the first six months of 2006 includes production from EnCana's Ecuador assets, which were sold in the first quarter 2006.

Key natural gas resource play production up 12 percent from past year

Second quarter 2007 natural gas production from key North American resource plays increased 12 percent to 2.67 Bcf/d compared to 2.38 Bcf/d in the second quarter of 2006. This was driven mainly by double-digit production increases in six of the company's nine gas resource plays, led by East Texas, CBM in central and southern Alberta, Cutbank Ridge in northeast British Columbia, Bighorn in west-central Alberta, Jonah in Wyoming and the Barnett Shale play in the Fort Worth basin. Gross oilsands production from Foster Creek and Christina Lake was up 43 percent to about 56,000 bbls/d (about 28,000 bbls/d net to EnCana). Overall, second quarter gas and oil resource play production increased 8 percent in the past year (13 percent on a pro forma basis as reflected in the table below).

Growth from key North American resource plays

Resource Play	Daily Production								
	2007			2006					2005
(After royalties)	YTD	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas (MMcf/d)									
Jonah	**514**	**523**	504	464	487	455	450	461	435
Piceance	**342**	**349**	334	326	335	331	324	316	307
East Texas	**121**	**139**	103	99	95	106	93	99	90
Fort Worth	**115**	**124**	106	101	99	104	108	93	70
Greater Sierra	**202**	**219**	186	213	212	209	224	208	219
Cutbank Ridge	**218**	**226**	210	170	199	167	173	140	92
Bighorn	**109**	**115**	104	91	99	97	95	72	55
CBM[1]	**248**	**245**	251	194	211	209	179	177	112
Shallow Gas[2]	**732**	**729**	735	739	737	734	730	756	765
Total natural gas (MMcf/d)	**2,601**	**2,669**	2,533	2,397	2,474	2,412	2,376	2,322	2,145
Oil (Mbbls/d)									
Foster Creek[3]	**23**	**25**	20	18	21	19	16	18	14
Christina Lake[3]	**3**	**3**	3	3	3	3	3	3	3
Pelican Lake[4]	**23**	**23**	23	24	20	23	22	29	26
Total oil (Mbbls/d)	**49**	**51**	46	45	44	45	41	50	43
Total (MMcfe/d)	**2,892**	**2,972**	2,811	2,667	2,736	2,680	2,624	2,624	2,403
% change from prior period		**5.7**	2.7	11.0	2.1	2.1	-	-2.9	

1 CBM integrated volumes were restated in 2006 to report commingled volumes from the coal and sand intervals based on regulatory approval.

2 Shallow Gas volumes were restated in the first quarter 2007 to report commingled volumes from multiple zones within the same geographic area based upon regulatory approval.

3 Foster Creek and Christina Lake volumes in 2006 and 2005 were restated in the first quarter 2007 on a pro forma basis to reflect the integrated oilsands transaction.

4 Pelican Lake reached royalty payout in April 2006.

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled								
	2007			2006					2005
	YTD	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas									
Jonah	**81**	**42**	39	163	41	48	48	26	104
Piceance	**137**	**72**	65	220	50	48	59	63	266
East Texas	**18**	**11**	7	59	11	12	17	19	84
Fort Worth	**43**	**29**	14	97	19	22	27	29	59
Greater Sierra	**55**	**32**	23	115	5	16	34	60	164
Cutbank Ridge	**52**	**25**	27	116	19	35	36	26	135
Bighorn	**37**	**9**	28	52	7	7	18	20	51
CBM[1]	**426**	**18**	408	729	157	156	35	381	1,245
Shallow Gas[2]	**657**	**241**	416	1,310	389	475	217	229	1,389
Oil									
Foster Creek[3]	**9**	**1**	8	3	-	-	-	3	20
Christina Lake[3]	**2**	**2**	-	1	-	-	-	1	-
Pelican Lake	-	-	-	-	-	-	-	-	52
Total	**1,517**	**482**	1,035	2,865	698	819	491	857	3,568

1 CBM integrated net wells drilled were restated in 2006 to report commingled volumes from the coal and sand intervals based on regulatory approval.
2 Shallow Gas net wells drilled were restated in the first quarter 2007 as a result of reporting commingled volumes from multiple zones within the same geographic area based upon regulatory approval.
3 Foster Creek and Christina Lake net wells drilled in 2006 and 2005 were restated in the first quarter 2007 on a pro forma basis to reflect the integrated oilsands transaction.

Second quarter 2007 natural gas and oil prices

	Q2 2007	Q2 2006	% Δ	6 months 2007	6 months 2006	% Δ
Natural gas						
($/Mcf, realized prices include hedging)						
NYMEX	7.55	6.78	+ 11	7.16	7.88	- 9
EnCana Realized Gas Price	**7.62**	6.50	+ 17	**7.43**	6.82	+ 9
Oil and NGLs						
($/bbl, realized prices include hedging)						
WTI	65.02	70.72	- 8	61.68	67.13	- 8
Western Canadian Select (WCS)	45.84	53.17	- 14	43.85	43.98	0
Differential WTI/WCS	19.18	17.55	+ 9	17.83	23.15	- 23
EnCana Realized Liquids Price	**45.47**	49.01	- 7	**44.02**	39.66	+ 11
U.S. Gulf Coast 3-2-1 Crack Spread	24.28	17.26	+ 41	17.17	12.77	+ 34

Price risk management

Risk management positions at June 30, 2007 are presented in Note 19 to the unaudited Interim Consolidated Financial Statements. In the second quarter of 2007, EnCana's commodity price risk management measures resulted in realized gains of approximately $246 million after-tax, composed of a $256 million gain on gas hedges and a $10 million loss on oil hedges.

About 0.7 Bcf/d of 2008 gas production hedged at $8.56 per Mcf
EnCana has hedged about 0.7 billion cubic feet per day of expected 2008 gas production, at a price of $8.56 per Mcf. For the last half of 2007, EnCana has about 1.8 Bcf/d of gas production with downside price protection, composed of 1.59 Bcf/d under fixed price contracts at an average NYMEX equivalent price of $8.58 per Mcf and 240 million cubic feet per day with put options at a NYMEX equivalent strike price of $6.00 per Mcf. EnCana has hedged 23,000 bbls/d of 2008 oil production at a price of WTI $70.13 per bbl. EnCana also has about 126,000 bbls/d of 2007 oil production with downside price protection, composed of 34,500 bbls/d under fixed price contracts at an average West Texas Intermediate (WTI) price of $64.40 per bbl, plus put options on 91,500 bbls/d at an average strike price of WTI $55.34 per bbl. This price hedging strategy helps reduce uncertainty in cash flow during periods of commodity price volatility.

North American natural gas prices are impacted by volatile pricing disconnects caused primarily by transportation constraints between producing regions and consuming regions. These price discounts are called basis differentials. For 2007 EnCana has hedged 100 percent of its U.S. Rockies basis exposure using a combination of downstream transportation and basis hedges. The basis hedges were transacted at an annual average differential of NYMEX less $0.67 per Mcf. During the second quarter of 2007 the U.S. Rockies-NYMEX natural gas price differential averaged $3.70 per Mcf. In Canada for 2007, EnCana has hedged 33 percent of its AECO basis differential at $0.72 per Mcf. In the second quarter of 2007, the AECO basis differential averaged $0.90 per Mcf. During the second quarter, EnCana's basis hedging resulted in a realized gain of about $306 million. EnCana has an additional 32 percent of Canadian basis differential subject to transport and aggregator contracts.

Corporate developments

Quarterly dividend of 20 cents per share approved
EnCana's board of directors has approved a quarterly dividend of 20 cents per share, which is payable on September 28, 2007 to common shareholders of record as of September 14, 2007.

EnCana Normal Course Issuer Bid purchases
Through the first six months of 2007, EnCana has purchased 35.4 million shares at an average share price of US$51.10 under the company's Normal Course Issuer Bid. This represents about 4.6 percent of shares outstanding as at December 31, 2006. As at June 30, 2007, there were approximately 753 million common shares issued and outstanding. During 2007, EnCana expects to purchase about 5 percent of the shares outstanding as of the start of the year. The company plans to fund Normal Course Issuer Bid purchases with cash flow and proceeds from divestitures.

Financial strength

EnCana maintains a strong balance sheet, targeting a net debt-to-capitalization ratio between 30 and 40 percent. At June 30, 2007, the company's net debt-to-capitalization ratio was 29:71. EnCana's net debt-to-adjusted-EBITDA multiple, on a trailing 12-month basis, was 0.8 times at the end of the second quarter. The company expects its net debt-to-capitalization ratio to remain at the lower end of the targeted range.

In the second quarter of 2007, EnCana invested $1,172 million of capital in continuing operations. Net divestitures were $148 million, resulting in net capital investment in continuing operations of $1,024 million.

NOTE 1: Non-GAAP measures

This interim report contains references to cash flow, operating earnings and free cash flow.

- Cash flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows.
- Operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain 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 Notes issued from Canada, and the partnership contribution receivable and the effect of the reduction in 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 unrealized gains/losses that relate to U.S. dollar denominated Notes issued from Canada are for debt with maturity dates in excess of five years.
- Free cash flow is a non-GAAP measure that EnCana defines as cash flow in excess of core capital investment.

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 US$55 billion, EnCana is a leading North American unconventional natural gas and integrated oilsands 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, net debt-to-capitalization ratio, sustainable growth and returns, cash flow, cash flow per share and increases in net asset value); 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; planned expansion of in-situ oilsands production; anticipated crude oil and natural gas prices, including basis differentials for various regions; the expected impact of proposed Rockies Express Pipeline on Rockies basis differentials; anticipated expansion and production at Foster Creek and Christina Lake; anticipated increased capacity for the two U.S. refineries; anticipated integrated oilsands cash flow; projections for future crack spreads and anticipated refining profits; anticipated drilling inventory; expected proportion of total production and cash flows contributed by natural gas; anticipated success of EnCana's market risk mitigation strategy and EnCana's ability to reduce uncertainty in cash flow during periods of commodity price volatility and provide downside price protection; anticipated purchases pursuant to the Normal Course Issuer Bid and the source of funding therefor; potential demand for natural gas; anticipated bitumen production in 2007 and beyond; anticipated drilling; potential capital expenditures and investment; potential oil, natural gas and NGLs production in 2007 and beyond; anticipated costs and inflationary pressures; potential risks associated with drilling 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 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 heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology; the company's ability to 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 environmental and other regulations or the interpretations of such 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.

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 in conjunction with the unaudited Interim Consolidated Financial Statements ("Interim Consolidated Financial Statements") for the period ended June 30, 2007, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2006. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this MD&A.

The Interim Consolidated Financial Statements and comparative information have been prepared in United States dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated July 24, 2007.

Readers can find the definition of certain terms used in this MD&A in the disclosure regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana contained in the Advisories section located at the end of this MD&A.

EnCana's Business

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

EnCana operates three continuing businesses:

- Canada, United States ("U.S.") and Other includes the Company's upstream exploration for, and development and production of natural gas, crude oil and natural gas liquids ("NGLs") and other related activities. The majority of the Company's upstream operations are located in Canada and the U.S. Offshore and international exploration is mainly focused on opportunities in the Middle East, Greenland and France.
- Integrated Oilsands is focused on two lines of business: the exploration for, and development and production of heavy oil from oilsands in Canada using in-situ recovery methods; and the refining of crude oil into petroleum and chemical products in the U.S. This segment represents EnCana's 50 percent interest in the joint venture with ConocoPhillips.
- Market Optimization is focused on enhancing the sale of EnCana's upstream production. As part of these activities, Market Optimization buys and sells third party products to enhance EnCana's operational flexibility for transportation commitments, product type, delivery points and customer diversification.

2007 versus 2006 Results Review

In the second quarter of 2007 compared to the second quarter of 2006, EnCana:

- Reported a 39 percent increase in Cash Flow from Continuing Operations to $2,549 million including $441 million of Operating Cash Flow from U.S. refinery operations;
- Reported a 64 percent increase in Operating Earnings from Continuing Operations to $1,376 million;
- Reported a 9 percent decrease in Net Earnings from Continuing Operations to $1,446 million primarily due to a significant future tax recovery resulting from tax rate reductions in 2006;
- Grew natural gas production 4 percent to 3,506 million cubic feet ("MMcf") of gas per day ("MMcf/d");
- Increased production from natural gas key resource plays 12 percent;
- Grew crude oil production 43 percent at Foster Creek and Christina Lake to 55,988 barrels per day ("bbls/d"). After reflecting the 50 percent contribution to the joint venture with ConocoPhillips, EnCana's reported production from these two properties decreased 29 percent to 27,994 bbls/d;
- Reported a 9 percent increase in natural gas prices to $6.38 per thousand cubic feet ("Mcf"). Realized natural gas prices, including the impact of financial hedging, averaged $7.62 per Mcf, an increase of 17 percent;
- Completed the sale of certain assets in the Mackenzie Delta and Beaufort Sea for $159 million; and
- Purchased approximately 12 million of its Common Shares at an average price of $59.23 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of $713 million in 2007.

In the six months of 2007 compared to the six months of 2006, EnCana:

- Reported a 26 percent increase in Cash Flow from Continuing Operations to $4,301 million including $550 million of Operating Cash Flow from U.S. refinery operations;
- Reported a 49 percent increase in Operating Earnings from Continuing Operations to $2,234 million;
- Reported a 37 percent decrease in Net Earnings from Continuing Operations to $1,943 million primarily due to after-tax unrealized mark-to-market losses in 2007 compared with gains and a significant future tax recovery resulting from tax rate reductions in 2006;
- Grew natural gas production 3 percent to 3,454 MMcf/d;
- Increased production from natural gas key resource plays 11 percent;
- Grew crude oil production 26 percent at Foster Creek and Christina Lake to 51,290 bbls/d. After reflecting the 50 percent contribution to the joint venture with ConocoPhillips, EnCana's reported production from these two properties decreased 37 percent to 25,645 bbls/d;
- Reported a 6 percent decrease in natural gas prices to $6.35 per Mcf. Realized natural gas prices, including the impact of financial hedging, averaged $7.43 per Mcf, an increase of 9 percent;
- Completed the sale of certain assets in the Mackenzie Delta and Beaufort Sea for $159 million and interests in Chad for $207 million;
- Purchased 35.4 million of its Common Shares at an average price of $51.10 per share under the NCIB for a total cost of $1,807 million in 2007;
- Increased its quarterly dividend to 20 cents per share; and
- Formed an integrated North American heavy oil business with ConocoPhillips.

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 foreign exchange rate. The following table shows select market benchmark prices and foreign exchange rates:

	Three Months Ended June 30			**Six Months Ended June 30**		
(Average for the period)	**2007**	**2007 vs 2006**	2006	**2007**	**2007 vs 2006**	2006
Natural Gas Price Benchmarks						
AECO Price *(C$/Mcf)*	**$ 7.37**	**18%**	$ 6.27	**$ 7.41**	**-5%**	$ 7.77
NYMEX Price *($/MMBtu)*	**7.55**	**11%**	6.78	**7.16**	**-9%**	7.88
Rockies (Opal) Price *($/MMBtu)*	**3.85**	**-28%**	5.36	**4.70**	**-25%**	6.27
Basis Differential *($/MMBtu)*						
AECO/NYMEX	**0.90**	**-27%**	1.23	**0.65**	**-39%**	1.06
Rockies/NYMEX	**3.70**	**161%**	1.42	**2.46**	**53%**	1.61
Crude Oil Price Benchmarks						
WTI *($/bbl)*	**65.02**	**-8%**	70.72	**61.68**	**-8%**	67.13
WCS *($/bbl)*	**45.84**	**-14%**	53.17	**43.85**	**-**	43.98
Differential - WTI/WCS *($/bbl)*	**19.18**	**9%**	17.55	**17.83**	**-23%**	23.15
USGC 3-2-1 Crack Spread *($/bbl)* (1)	**24.28**	**41%**	17.26	**17.17**	**34%**	12.77
Foreign Exchange						
U.S./Canadian Dollar Exchange Rate	**0.911**	**2%**	0.892	**0.881**	**-**	0.879

(1) 3-2-1 Crack Spread is the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of diesel.

Acquisitions and Divestitures

Six Months Ended June 30

In keeping with EnCana's North American resource play strategy, the Company completed the following significant divestitures in 2007:

- The sale of certain assets in the Mackenzie Delta and Beaufort Sea on May 30 for $159 million; and
- The sale of its interests in Chad on January 12 for $207 million resulting in a gain on sale of $59 million.

In addition to these Upstream divestitures, EnCana completed the sale of The Bow office project assets on February 9 for approximately $57 million, largely representing its investment at the date of sale.

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

Consolidated Financial Results

($ millions, except per share amounts)	Six Months Ended June 30		2007		2006				2005	
	2007	2006	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Total Consolidated										
Cash Flow [1]	**$ 4,301**	$ 3,506	**$ 2,549**	$ 1,752	$ 1,761	$ 1,894	$ 1,815	$ 1,691	$ 2,510	$ 1,931
- per share – diluted	**5.56**	4.10	**3.33**	2.25	2.18	2.30	2.15	1.96	2.88	2.20
Net Earnings	**1,943**	3,631	**1,446**	497	663	1,358	2,157	1,474	2,366	266
- per share – basic	**2.54**	4.33	**1.91**	0.65	0.84	1.68	2.60	1.74	2.77	0.31
- per share – diluted	**2.51**	4.24	**1.89**	0.64	0.82	1.65	2.55	1.70	2.71	0.30
Operating Earnings [2]	**2,234**	1,518	**1,376**	858	675	1,078	824	694	1,271	704
- per share – diluted	**2.89**	1.77	**1.80**	1.10	0.84	1.31	0.98	0.80	1.46	0.80
Continuing Operations										
Cash Flow from Continuing Operations [1]	**4,301**	3,418	**2,549**	1,752	1,742	1,883	1,839	1,579	2,390	1,823
Net Earnings from Continuing Operations	**1,943**	3,065	**1,446**	497	643	1,343	1,593	1,472	1,869	348
- per share – basic	**2.54**	3.65	**1.91**	0.65	0.81	1.66	1.92	1.74	2.19	0.41
- per share – diluted	**2.51**	3.58	**1.89**	0.64	0.80	1.63	1.88	1.70	2.14	0.40
Operating Earnings from Continuing Operations [2]	**2,234**	1,501	**1,376**	858	672	1,064	841	660	1,229	733
Revenues, Net of Royalties	**10,049**	8,694	**5,613**	4,436	3,676	4,029	3,922	4,772	5,933	3,061

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

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

CASH FLOW

Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows. Cash Flow from Continuing Operations is a non-GAAP measure defined as Cash Flow excluding Cash Flow from Discontinued Operations, which is defined on the Consolidated Statement of Cash Flows. While Cash Flow measures are considered non-GAAP, they are commonly used in the oil and gas industry and are used by EnCana to assist management and investors in measuring the Company's ability to finance capital programs and meet financial obligations.

Three Months Ended June 30, 2007 versus 2006

Cash Flow from Continuing Operations in the second quarter of 2007 increased $710 million or 39 percent compared to the second quarter of 2006.

The increase in Cash Flow from Continuing Operations resulted from:

- Operating Cash Flow from U.S. refinery operations was $441 million in 2007 with no comparative amount in 2006;
- Cash tax recovery resulting from a Canadian federal corporate tax legislative change of $174 million;
- Average North American natural gas prices, excluding financial hedges, increased 9 percent to $6.38 per Mcf in 2007 compared to $5.84 per Mcf in 2006;
- Realized financial natural gas and crude oil commodity hedging gains were $246 million after-tax in 2007 compared with gains of $106 million after-tax in 2006; and
- Natural gas production volumes in 2007 increased 4 percent to 3,506 MMcf/d from 3,361 MMcf/d in 2006.

Cash Flow from Continuing Operations was reduced by:

- Average North American liquids prices, excluding financial hedges, decreased 11 percent to $46.81 per bbl in 2007 compared to $52.44 per bbl in 2006; and
- North American liquids production volumes in 2007 decreased 12 percent to 133,416 bbls/d from 151,859 bbls/d in 2006. This decrease reflects the increased production volumes at Foster Creek and Christina Lake offset by EnCana's 50 percent contribution of these properties to the joint venture with ConocoPhillips and natural declines in conventional properties.

Six Months Ended June 30, 2007 versus 2006

Cash Flow from Continuing Operations in the six months of 2007 increased $883 million or 26 percent compared to the same period in 2006.

The increase in Cash Flow from Continuing Operations resulted from:

- Operating Cash Flow from U.S. refinery operations was $550 million in 2007 with no comparative amount in 2006;
- Realized financial natural gas and crude oil commodity hedging gains were $454 million after-tax in 2007 compared with losses of $30 million after-tax in 2006;
- Cash tax recovery resulting from a Canadian federal corporate tax legislative change of $174 million; and
- Natural gas production volumes in 2007 increased 3 percent to 3,454 MMcf/d from 3,352 MMcf/d in 2006.

Cash Flow from Continuing Operations was reduced by:

- Average North American natural gas prices, excluding financial hedges, decreased 6 percent to $6.35 per Mcf in 2007 compared to $6.75 per Mcf in 2006; and
- North American liquids production volumes in 2007 decreased 17 percent to 132,010 bbls/d from 158,878 bbls/d in 2006. This decrease reflects the increased production volumes at Foster Creek and Christina Lake offset by EnCana's 50 percent contribution of these properties to the joint venture with ConocoPhillips, the Pelican Lake royalty payout in April 2006 and natural declines in conventional properties.

NET EARNINGS

Three Months Ended June 30, 2007 versus 2006

EnCana's second quarter 2007 Net Earnings were $711 million lower compared to 2006 primarily due to a net gain of $582 million after-tax on sale of the gas storage business and Ecuador assets in 2006.

EnCana's second quarter 2007 Net Earnings from Continuing Operations were $147 million lower compared to 2006. In addition to the items affecting Cash Flow as detailed previously, significant items affecting Net Earnings were:

- Future tax recovery due to Canadian federal tax rate reductions of $37 million in 2007 compared to federal and provincial tax rate reductions of $457 million in 2006;
- Foreign exchange losses of $7 million in 2007 compared with gains of $202 million in 2006;
- Unrealized mark-to-market gains of $47 million after-tax in 2007 compared with gains of $161 million after-tax in 2006; and

- Future tax recovery due to a Canadian federal corporate tax legislative change of $57 million in 2007 with no comparative amount in 2006.

Six Months Ended June 30, 2007 versus 2006

EnCana's six months 2007 Net Earnings were $1,688 million lower compared to 2006 due to a net gain of $535 million after-tax on sale of the gas storage business and Ecuador assets in 2006 and the items discussed below.

EnCana's six months 2007 Net Earnings from Continuing Operations were $1,122 million lower compared to 2006. In addition to the items affecting Cash Flow as detailed previously, significant items affecting Net Earnings were:

- Unrealized mark-to-market losses of $376 million after-tax in 2007 compared with gains of $976 million after-tax in 2006;
- Future tax recovery due to Canadian federal tax rate reductions of $37 million in 2007 compared to federal and provincial tax rate reductions of $457 million in 2006;
- Foreign exchange gains of $5 million in 2007 compared with gains of $158 million in 2006;
- A gain on sale of approximately $59 million from the sale of EnCana's interest in Chad; and
- Future tax recovery due to a Canadian federal corporate tax legislative change of $57 million in 2007 with no comparative amount in 2006.

There were no discontinued operations in 2007. Additional information on discontinued operations for the comparative periods in 2006 can be found in Note 7 to the Interim Consolidated Financial Statements.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that adjust Net Earnings and Net Earnings from Continuing Operations by non-operating items that Management believes reduce the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings and Operating Earnings from Continuing Operations 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			
	2007		2006		**2007**		2006	
($ millions, except per share amounts)		**Per share(4)**		Per share(4)		**Per share(4)**		Per share(4)
Net Earnings, as reported	**$ 1,446**	**$ 1.89**	$ 2,157	$ 2.55	**$ 1,943**	**$ 2.51**	$ 3,631	$ 4.24
Add back (losses) and deduct gains:								
- Unrealized mark-to-market accounting gain (loss), after-tax	**47**	**0.06**	160	0.19	**(376)**	**(0.49)**	990	1.16
- Unrealized foreign exchange gain (loss), after-tax (1)	**(14)**	**(0.02)**	134	0.15	**(11)**	**(0.01)**	131	0.15
- Gain (loss) on discontinuance, after-tax	**-**	**-**	582	0.69	**59**	**0.07**	535	0.63
- Future tax recovery due to tax rate reductions	**37**	**0.05**	457	0.54	**37**	**0.05**	457	0.53
Operating Earnings (2) (3)	**$ 1,376**	**$ 1.80**	$ 824	$ 0.98	**$ 2,234**	**$ 2.89**	$ 1,518	$ 1.77

(1) Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt and the partnership contribution receivable, after-tax. The majority of the unrealized gains or losses that relate to U.S. dollar debt issued from Canada and the partnership contribution receivable have maturity dates in excess of five years.

(2) Operating Earnings is a non-GAAP measure that shows Net Earnings excluding the after-tax gain or loss on discontinuance, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable and the effect of the changes in statutory income tax rates.

(3) Unrealized gains or losses have no impact on Cash Flow.

(4) Per Common Share – diluted.

Summary of Operating Earnings from Continuing Operations

($ millions)	Three Months Ended June 30 2007	2006	Six Months Ended June 30 2007	2006
Net Earnings from Continuing Operations, as reported	**$ 1,446**	$ 1,593	**$ 1,943**	$ 3,065
Add back (losses) and deduct gains:				
- Unrealized mark-to-market accounting gain (loss), after-tax	**47**	161	**(376)**	976
- Unrealized foreign exchange gain (loss), after-tax (1)	**(14)**	134	**(11)**	131
- Gain (loss) on discontinuance, after-tax	**-**	-	**59**	-
- Future tax recovery due to tax rate reductions	**37**	457	**37**	457
Operating Earnings from Continuing Operations (2) (3)	**$ 1,376**	$ 841	**$ 2,234**	$ 1,501

(1) Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt and the partnership contribution receivable, after-tax. The majority of the unrealized gains or losses that relate to U.S. dollar debt issued from Canada and the partnership contribution receivable have maturity dates in excess of five years.

(2) Operating Earnings from Continuing Operations is a non-GAAP measure that shows Net Earnings from Continuing Operations excluding the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable and the effect of the changes in statutory income tax rates.

(3) Unrealized gains or losses have no impact on Cash Flow.

RESULTS OF OPERATIONS

UPSTREAM OPERATIONS

Production Volumes

	Six Months Ended June 30		2007		2006				2005	
	2007	2006	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Produced Gas *(MMcf/d)*	**3,454**	3,352	**3,506**	3,400	3,406	3,359	3,361	3,343	3,326	3,222
Crude Oil *(bbls/d)*	**108,319**	134,467	**108,916**	107,715	130,563	132,814	127,459	141,552	138,241	126,425
NGLs *(bbls/d)*	**23,691**	24,410	**24,500**	22,875	24,106	23,907	24,400	24,421	25,111	26,055
Continuing Operations *(MMcfe/d)* (1)	**4,246**	4,305	**4,306**	4,184	4,334	4,299	4,272	4,339	4,306	4,137
Discontinued Operations Ecuador *(bbls/d)*	**-**	24,191	**-**	-	-	-	-	48,650	70,480	71,896
Discontinued Operations *(MMcfe/d)* (1)(2)	**-**	145	**-**	-	-	-	-	292	423	432
Total *(MMcfe/d)* (1)	**4,246**	4,450	**4,306**	4,184	4,334	4,299	4,272	4,631	4,729	4,569

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

(2) Completed the sale of Ecuador on February 28, 2006.

Production volumes from continuing operations increased 1 percent or 34 MMcfe/d in the second quarter of 2007 compared to 2006 and decreased 1 percent or 59 MMcfe/d in the six months of 2007 compared to 2006 due to:

- Increased production from EnCana's natural gas key resource plays of 12 percent in the second quarter of 2007 and 11 percent in the six months of 2007 compared to 2006; offset by

- Decreased production from EnCana's crude oil key resource plays of 16 percent in the second quarter of 2007 and 26 percent in the six months of 2007 compared to 2006 after reflecting the 50 percent contribution of Foster Creek and Christina Lake to the joint venture with ConocoPhillips and as a result of natural declines in conventional properties.

Key Resource Plays

	Three Months Ended June 30					Six Months Ended June 30				
	Daily Production			Drilling Activity (net wells drilled)		Daily Production			Drilling Activity (net wells drilled)	
	2007	**2007 vs 2006**	2006	**2007**	2006	**2007**	**2007 vs 2006**	2006	**2007**	2006
Natural Gas ***(MMcf/d)***										
Jonah	**523**	**16%**	450	**42**	48	**514**	**13%**	456	**81**	74
Piceance	**349**	**8%**	324	**72**	59	**342**	**7%**	320	**137**	122
East Texas	**139**	**49%**	93	**11**	17	**121**	**26%**	96	**18**	36
Fort Worth	**124**	**15%**	108	**29**	27	**115**	**14%**	101	**43**	56
Greater Sierra	**219**	**-2%**	224	**32**	34	**202**	**-6%**	216	**55**	94
Cutbank Ridge	**226**	**31%**	173	**25**	36	**218**	**39%**	157	**52**	62
Bighorn	**115**	**21%**	95	**9**	18	**109**	**30%**	84	**37**	38
CBM [(1)]	**245**	**37%**	179	**18**	35	**248**	**39%**	178	**426**	416
Shallow Gas	**729**	**-**	730	**241**	217	**732**	**-1%**	743	**657**	446
	2,669	**12%**	2,376	**479**	491	**2,601**	**11%**	2,351	**1,506**	1,344
Oil ***(Mbbls/d)***										
Foster Creek	**50**	**52%**	33	**2**	-	**46**	**31%**	35	**17**	6
Christina Lake	**6**	**-**	6	**5**	-	**5**	**-17%**	6	**5**	2
Partner's 50% Interest	**(28)**	**-**	-	**(4)**	-	**(25)**	**-**	-	**(11)**	-
	28	**-29%**	39	**3**	-	**26**	**-37%**	41	**11**	8
Pelican Lake	**23**	**5%**	22	**-**	-	**23**	**-8%**	25	**-**	-
	51	**-16%**	61	**3**	-	**49**	**-26%**	66	**11**	8
Total ***(MMcfe/d)***	**2,972**	**8%**	2,741	**482**	491	**2,892**	**5%**	2,745	**1,517**	1,352

(1) CBM volumes and net wells drilled include commingled results from the coal and sand intervals based upon regulatory approval.

Produced Gas

Three Months Ended June 30, 2007 versus 2006

Financial Results from Continuing Operations

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

2007	Canada	Canada $/Mcf	United States	United States $/Mcf	Total	Total $/Mcf
Revenues, Net of Royalties / Price	**$ 1,361**	**$ 6.76**	**$ 679**	**$ 5.73**	**$ 2,040**	**$ 6.38**
Realized Financial Hedging	**85**		**310**		**395**	
Expenses						
Production and mineral taxes	**22**	**0.11**	**20**	**0.17**	**42**	**0.14**
Transportation and selling	**73**	**0.36**	**77**	**0.65**	**150**	**0.47**
Operating	**180**	**0.90**	**85**	**0.71**	**265**	**0.83**
Operating Cash Flow / Netback [(1)]	**$ 1,171**	**$ 5.39**	**$ 807**	**$ 4.20**	**$ 1,978**	**$ 4.94**
Gas Production Volumes *(MMcf/d)*		**2,203**		**1,303**		**3,506**

2006	Canada	Canada $/Mcf	United States	United States $/Mcf	Total	Total $/Mcf
Revenues, Net of Royalties / Price	$ 1,141	$ 5.71	$ 647	$ 6.08	$ 1,788	$ 5.84
Realized Financial Hedging	155		48		203	
Expenses						
Production and mineral taxes	15	0.08	23	0.22	38	0.13
Transportation and selling	71	0.35	52	0.50	123	0.40
Operating	153	0.77	75	0.70	228	0.74
Operating Cash Flow / Netback [(1)]	$ 1,057	$ 4.51	$ 545	$ 4.66	$ 1,602	$ 4.57
Gas Production Volumes *(MMcf/d)*		2,192		1,169		3,361

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

Produced Gas Revenue Variances for 2007 Compared to 2006 from Continuing Operations

($ millions)

	2006 Revenues, Net of Royalties	Revenue Variances in: Price [(1)]	Revenue Variances in: Volume	**2007 Revenues, Net of Royalties**
Canada	$ 1,296	$ 143	$ 7	**$ 1,446**
United States	695	192	102	**989**
Total Produced Gas	$ 1,991	$ 335	$ 109	**$ 2,435**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties from produced gas, increased in the second quarter of 2007 compared with the same period in 2006 due to:

- A 9 percent increase in North American natural gas prices, excluding the impact of financial hedging, and a 4 percent increase in natural gas production volumes; and
- Realized financial commodity hedging gains totaled $395 million in 2007 or $1.24 per Mcf compared to gains of $203 million or $0.66 per Mcf in 2006.

Produced gas volumes in Canada were relatively unchanged in 2007. Drilling success in the key resource plays of Coalbed Methane ("CBM") in central and southern Alberta, Cutbank Ridge in northeast British Columbia and Bighorn in west central Alberta was offset by natural declines for conventional properties. Produced gas volumes in the U.S. increased 11 percent in 2007 as a result of drilling success at Jonah, East Texas, Fort Worth and Piceance.

The increase in EnCana's North American natural gas price in 2007, excluding the impact of financial hedges, is primarily the result of the increase in AECO and NYMEX benchmark prices.

Natural gas per unit production and mineral taxes, which are generally calculated as a percentage of revenues, increased in 2007 compared to 2006 for Canada mainly due to higher natural gas prices. Natural gas per unit production and mineral taxes in the U.S. decreased $0.05 per Mcf or 23 percent in 2007 compared to 2006 mainly as a result of lower natural gas prices in the U.S. Rockies and a reduction in the severance and ad valorem taxes paid for Colorado properties.

Natural gas per unit transportation and selling costs for the U.S. increased 30 percent or $0.15 per Mcf in 2007 compared to 2006 primarily as a result of higher transportation rates in the Piceance and Fort Worth areas and firm transportation commitments in Piceance.

Natural gas per unit operating expenses for Canada in 2007 were 17 percent or $0.13 per Mcf higher than in 2006 as a result of increased property taxes and lease rentals, repairs and maintenance due to plant turnarounds and the higher U.S./Canadian dollar exchange rate. Operating costs in both Canada and the U.S. were also impacted by higher long-term compensation costs in 2007 compared to 2006 due to increases in the EnCana share price, which resulted in a $0.05 per Mcf increase in operating costs for North American natural gas.

Six Months Ended June 30, 2007 versus 2006

Financial Results from Continuing Operations

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

	2007					
	Canada		**United States**		**Total**	
		$/Mcf		**$/Mcf**		**$/Mcf**
Revenues, Net of Royalties / Price	**$ 2,611**	**$ 6.56**	**$ 1,366**	**$ 5.97**	**$ 3,977**	**$ 6.35**
Realized Financial Hedging	**223**		**454**		**677**	
Expenses						
Production and mineral taxes	**42**	**0.11**	**78**	**0.34**	**120**	**0.19**
Transportation and selling	**143**	**0.36**	**143**	**0.63**	**286**	**0.46**
Operating	**357**	**0.90**	**160**	**0.69**	**517**	**0.82**
Operating Cash Flow / Netback (1)	**$ 2,292**	**$ 5.19**	**$ 1,439**	**$ 4.31**	**$ 3,731**	**$ 4.88**
Gas Production Volumes *(MMcf/d)*		**2,191**		**1,263**		**3,454**

	2006					
	Canada		United States		Total	
		$/Mcf		$/Mcf		$/Mcf
Revenues, Net of Royalties / Price	$ 2,654	$ 6.68	$ 1,452	$ 6.88	$ 4,106	$ 6.75
Realized Financial Hedging	83		(39)		44	
Expenses						
Production and mineral taxes	51	0.13	112	0.53	163	0.27
Transportation and selling	138	0.35	118	0.50	256	0.40
Operating	306	0.78	143	0.67	449	0.74
Operating Cash Flow / Netback (1)	$ 2,242	$ 5.42	$ 1,040	$ 5.18	$ 3,282	$ 5.34
Gas Production Volumes *(MMcf/d)*		2,187		1,165		3,352

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

Produced Gas Revenue Variances for 2007 Compared to 2006 from Continuing Operations

($ millions)

	2006 Revenues, Net of Royalties	Revenue Variances in: Price (1)	Volume	**2007 Revenues, Net of Royalties**
Canada	$ 2,737	$ 92	$ 5	**$ 2,834**
United States	1,413	266	141	**1,820**
Total Produced Gas	$ 4,150	$ 358	$ 146	**$ 4,654**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties from produced gas, increased in the six months of 2007 compared with the same period in 2006 due to:

- A 3 percent increase in natural gas production volumes offset by a 6 percent decrease in North American gas prices, excluding the impact of financial hedging; and
- Realized financial commodity hedging gains totaled $677 million or $1.08 per Mcf in 2007 compared to gains of $44 million or $0.07 per Mcf in 2006.

Produced gas volumes in Canada were relatively unchanged in 2007. Drilling success in the key resource plays of CBM, Cutbank Ridge and Bighorn was offset by natural declines for conventional properties and the Greater Sierra key resource play. Produced gas volumes in the U.S. increased 8 percent in 2007 as a result of drilling success at Jonah, East Texas, Fort Worth and Piceance.

The decrease in EnCana’s North American natural gas price in 2007, excluding the impact of financial hedges, is primarily the result of the decline in AECO and NYMEX benchmark prices.

Natural gas per unit production and mineral taxes for Canada decreased in 2007 compared to 2006 mainly due to lower natural gas prices. Natural gas per unit production and mineral taxes in the U.S. decreased $0.19 per Mcf or 36 percent in 2007 compared to 2006 mainly as a result of lower natural gas prices in the U.S. Rockies and a reduction in the severance and ad valorem taxes paid for Colorado properties.

Natural gas per unit transportation and selling costs for the U.S. increased 26 percent or $0.13 per Mcf in 2007 compared to 2006 primarily as a result of higher transportation rates in the Piceance and Fort Worth areas and firm transportation commitments in Piceance.

Natural gas per unit operating expenses for Canada in 2007 were 15 percent or $0.12 per Mcf higher than in 2006 as a result of increased property taxes and lease rentals and repairs and maintenance expenses. Operating costs in both Canada and the U.S. were also impacted by higher long-term compensation costs in 2007 compared to 2006 due to increases in the EnCana share price, which resulted in a $0.04 per Mcf increase in operating costs for North American natural gas.

Crude Oil and NGLs

Three Months Ended June 30, 2007 versus 2006

Financial Results from Continuing Operations

($ millions)

	2007				2006			
	Canada	**United States**	**Foster Creek /Christina Lake**	**Total**	Canada	United States	Foster Creek /Christina Lake	Total
Revenues, Net of Royalties	**$ 383**	**$ 70**	**$ 172**	**$ 625**	$ 462	$ 71	$ 271	$ 804
Expenses								
Production and mineral taxes	**9**	**6**	**-**	**15**	9	4	-	13
Transportation and selling	**10**	**-**	**72**	**82**	7	-	130	137
Operating	**63**	**-**	**39**	**102**	55	-	44	99
Operating Cash Flow	**$ 301**	**$ 64**	**$ 61**	**$ 426**	$ 391	$ 67	$ 97	$ 555

Crude Oil and NGLs Revenue Variances for 2007 Compared to 2006 from Continuing Operations

($ millions)

	2006 Revenues, Net of Royalties	Revenue Variances in: Price (1)	Volume	**2007 Revenues, Net of Royalties**
Canada	$ 462	$ (47)	$ (32)	**$ 383**
United States	71	(3)	2	**70**
Foster Creek/Christina Lake	271	(30)	(69)	**172**
Total Crude Oil and NGLs	$ 804	$ (80)	$ (99)	**$ 625**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, decreased in the second quarter of 2007 compared with the same period in 2006 due to:

- An 11 percent decrease in North American liquids prices, excluding financial hedges, and a 12 percent decrease in North American liquids production volumes; and
- Realized financial commodity hedging losses totaled $16 million or $1.34 per bbl in 2007 compared to losses of $48 million or $3.43 per bbl in 2006.

Total crude oil production at Foster Creek and Christina Lake decreased 29 percent after reflecting the 50 percent contribution of Foster Creek and Christina Lake to the joint venture with ConocoPhillips. In addition, Canada crude oil production decreased 8 percent due to natural declines in conventional properties.

Six Months Ended June 30, 2007 versus 2006

Financial Results from Continuing Operations

($ millions)	**2007**				2006			
	Canada	**United States**	**Foster Creek /Christina Lake**	**Total**	Canada	United States	Foster Creek /Christina Lake	Total
Revenues, Net of Royalties	**$ 758**	**$ 124**	**$ 392**	**$ 1,274**	$ 770	$ 132	$ 454	$ 1,356
Expenses								
Production and mineral taxes	**17**	**12**	**-**	**29**	18	9	-	27
Transportation and selling	**20**	**-**	**196**	**216**	8	-	247	255
Operating	**123**	**-**	**88**	**211**	115	-	82	197
Operating Cash Flow	**$ 598**	**$ 112**	**$ 108**	**$ 818**	$ 629	$ 123	$ 125	$ 877

Crude Oil and NGLs Revenue Variances for 2007 Compared to 2006 from Continuing Operations

($ millions)

	2006 Revenues, Net of Royalties	Revenue Variances in: Price (1)	Volume	**2007 Revenues, Net of Royalties**
Canada	$ 770	$ 86	$ (98)	**$ 758**
United States	132	(10)	2	**124**
Foster Creek/Christina Lake	454	167	(229)	**392**
Total Crude Oil and NGLs	$ 1,356	$ 243	$ (325)	**$ 1,274**

(1) Includes the impact of realized financial hedging.

Revenues, net of royalties, decreased in the six months of 2007 compared with the same period in 2006 due to:

- A 17 percent decrease in North American liquids production volumes offset slightly by a 1 percent increase in North American liquids prices, excluding financial hedges; and

- Realized financial commodity hedging gains totaled $13 million or $0.52 per bbl in 2007 compared to losses of $93 million or $3.27 per bbl in 2006.

Total crude oil production at Foster Creek and Christina Lake decreased 37 percent after reflecting the 50 percent contribution of Foster Creek and Christina Lake to the joint venture with ConocoPhillips. In addition, Canada crude oil production decreased 12 percent due to natural declines in conventional properties and the Pelican Lake royalty payout in April 2006. EnCana's Pelican Lake property reached payout in April 2006 which increased the royalty payments to the Alberta Government and reduced EnCana's net revenue interest crude oil volumes by approximately 6,000 bbls/d from the point of payout.

Three Months Ended June 30, 2007 versus 2006

Per Unit Results – Crude Oil

	Canada(1)		**Foster Creek/ Christina Lake**	
($ per barrel)	**2007**	2006	**2007**	2006
Price (2)	**$ 47.02**	$ 55.58	**$ 39.40**	$ 46.53
Expenses				
Production and mineral taxes	**1.16**	1.28	**-**	-
Transportation and selling	**1.31**	0.76	**3.62**	3.38
Operating	**8.85**	6.84	**14.02**	11.78
Netback	**$ 35.70**	$ 46.70	**$ 21.76**	$ 31.37
Crude Oil Production Volumes *(bbls/d)*	**80,922**	88,244	**27,994**	39,215

(1) Excludes Foster Creek/Christina Lake.
(2) Excludes the impact of realized financial hedging.

Canada and Foster Creek/Christina Lake crude oil prices in 2007, excluding the impact of financial hedges, decreased 15 percent compared to 2006, which reflects the 14 percent decrease in the benchmark WCS crude oil price compared to 2006. Total realized financial commodity hedging losses were approximately $16 million or $1.34 per bbl of liquids in 2007 compared to losses of approximately $48 million or $3.43 per bbl of liquids in 2006.

Canada crude oil per unit production and mineral taxes decreased 9 percent or $0.12 per bbl in 2007 compared to 2006 primarily due to the impact of lower overall prices.

Canada crude oil per unit transportation and selling costs increased 72 percent or $0.55 per bbl in 2007 compared to 2006 primarily due to increased clean oil trucking costs at Weyburn and increased deliveries to the United States. Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2007 increased 7 percent or $0.24 per bbl compared to 2006 due to a slight increase in volumes being delivered to the U.S. Gulf Coast in 2007 compared to 2006.

Canada crude oil per unit operating costs in 2007 increased 29 percent or $2.01 per bbl compared to 2006 mainly due to increased workovers, electricity, chemicals and repairs and maintenance. Foster Creek/Christina Lake crude oil per unit operating costs increased 19 percent or $2.24 per bbl in 2007 compared to 2006. This reflected increased purchased fuel costs at Foster Creek to steam new well pairs prior to commencing production and increased repairs and maintenance. In addition, operating costs were impacted by the higher U.S./Canadian dollar exchange rate and higher long-term compensation costs in 2007 compared to 2006 due to the increase in the EnCana share price.

Six Months Ended June 30, 2007 versus 2006

Per Unit Results – Crude Oil

	Canada[1]		Foster Creek/ Christina Lake	
($ per barrel)	**2007**	2006	**2007**	2006
Price [2]	**$ 44.16**	$ 44.96	**$ 36.28**	$ 34.46
Expenses				
Production and mineral taxes	**1.11**	1.09	**-**	-
Transportation and selling	**1.29**	0.89	**3.33**	2.57
Operating	**8.44**	6.75	**15.60**	11.07
Netback	**$ 33.32**	$ 36.23	**$ 17.35**	$ 20.82
Crude Oil Production Volumes *(bbls/d)*	**82,674**	93,842	**25,645**	40,625

(1) Excludes Foster Creek/Christina Lake.
(2) Excludes the impact of realized financial hedging.

Canada and Foster Creek/Christina Lake crude oil prices in 2007, excluding the impact of financial hedges, changed slightly compared to 2006, which reflects the relatively stable benchmark WCS crude oil price compared to 2006. Total realized financial commodity hedging gains were approximately $13 million or $0.52 per bbl of liquids in 2007 compared to losses of approximately $93 million or $3.27 per bbl of liquids in 2006.

Canada crude oil per unit transportation and selling costs increased 45 percent or $0.40 per bbl in 2007 compared to 2006 primarily due to increased clean oil trucking costs at Weyburn and increased deliveries to the United States. Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2007 increased 30 percent or $0.76 per bbl compared to 2006 due to approximately 50 percent of volumes being delivered to the U.S. Gulf Coast in 2007 compared to approximately 25 percent in 2006.

Canada crude oil per unit operating costs in 2007 increased 25 percent or $1.69 per bbl compared to 2006 mainly due to increased workovers, chemicals, electricity and lower net revenue interest production at Pelican Lake as a result of royalty payout in April 2006. Foster Creek/Christina Lake crude oil per unit operating costs increased 41 percent or $4.53 per bbl in 2007 compared to 2006. This reflected increased purchased fuel costs at Foster Creek to steam new well pairs prior to commencing production, increased repairs and maintenance and workovers. In addition, operating costs were impacted by higher long-term compensation costs in 2007 compared to 2006 due to the increase in the EnCana share price.

Three Months Ended June 30, 2007 versus 2006

Per Unit Results – NGLs

	Canada		United States	
($ per barrel)	**2007**	2006	**2007**	2006
Price [1]	**$ 55.21**	$ 55.19	**$ 55.43**	$ 58.25
Expenses				
Production and mineral taxes	**-**	-	**4.71**	2.60
Transportation and selling	**0.74**	0.73	**0.01**	0.01
Netback	**$ 54.47**	$ 54.46	**$ 50.71**	$ 55.64
NGLs Production Volumes *(bbls/d)*	**11,017**	11,607	**13,483**	12,793

(1) Excludes the impact of realized financial hedging.

The change in NGLs prices in 2007 compared to 2006 generally correlates with lower WTI oil prices and is also affected by local market conditions.

U.S. NGLs per unit production and mineral taxes increased 81 percent or $2.11 per bbl in 2007 compared to 2006 mainly as a result of favorable adjustments recorded in 2006 related to severance and ad valorem tax assessments for Colorado properties.

Six Months Ended June 30, 2007 versus 2006

Per Unit Results – NGLs

	Canada		United States	
($ per barrel)	**2007**	2006	**2007**	2006
Price [1]	**$ 49.35**	$ 51.98	**$ 51.81**	$ 56.20
Expenses				
Production and mineral taxes	**-**	-	**4.64**	3.86
Transportation and selling	**0.64**	0.67	**0.01**	0.01
Netback	**$ 48.71**	$ 51.31	**$ 47.16**	$ 52.33
NGLs Production Volumes *(bbls/d)*	**10,859**	11,805	**12,832**	12,605

(1) Excludes the impact of realized financial hedging.

The decrease in NGLs prices in 2007 compared to 2006 generally correlates with lower WTI oil prices and is also affected by local market conditions.

U.S. NGLs per unit production and mineral taxes increased 20 percent or $0.78 per bbl in 2007 compared to 2006 mainly as a result of favorable adjustments recorded in 2006 related to severance and ad valorem tax assessments for Colorado properties.

Upstream Depreciation, Depletion and Amortization

Three Months Ended June 30, 2007 versus 2006
Upstream Depreciation, depletion and amortization ("DD&A") expenses in the second quarter of 2007 increased $77 million or 11 percent from the same period in 2006. Unit of production DD&A rates were higher in 2007 compared to 2006 primarily as a result of increased future development costs.

Six Months Ended June 30, 2007 versus 2006
Upstream DD&A expenses in the six months of 2007 increased $126 million or 9 percent from the same period in 2006. Unit of production DD&A rates were higher in 2007 compared to 2006 primarily as a result of increased future development costs.

DOWNSTREAM OPERATIONS

Financial Results ($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2007	2006	**2007**	2006
Revenues	**$ 1,717**	$ -	**$ 3,060**	$ -
Expenses				
Operating	**119**	-	**219**	-
Purchased product	**1,157**	-	**2,291**	-
Operating Cash Flow	**$ 441**	$ -	**$ 550**	$ -

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

Revenues reflect EnCana's 50 percent share of the sale of petroleum products in the United States. Operating Cash Flow during the second quarter of 2007 was impacted by significantly higher refining margins. On a 100 percent basis, the two refineries have a combined crude oil refining capacity of 452,000 bbls/d and operated at 88 percent of that capacity during the second quarter and 92 percent during the six months of 2007. Including the addition of other processed inputs combined with crude oil, refined products averaged 421,000 bbls/d through the second quarter and 439,000 bbls/d through the six months of 2007.

Purchased products, consisting mainly of crude oil, represented 91 percent of total expenses in the second quarter and six months of 2007. Operating costs for labour, utilities and supplies comprised the balance of expenses for the quarter and six months of 2007.

MARKET OPTIMIZATION

Financial Results ($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2007	2006	**2007**	2006
Revenues	**$ 722**	$ 825	**$ 1,478**	$ 1,541
Expenses				
Transportation and selling	**2**	10	**10**	13
Operating	**10**	13	**17**	31
Purchased product	**702**	794	**1,434**	1,483
Operating Cash Flow	**8**	8	**17**	14
Depreciation, depletion and amortization	**4**	2	**7**	5
Segment Income (Loss)	**$ 4**	$ 6	**$ 10**	$ 9

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.

CORPORATE

Financial Results ($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2007	2006	**2007**	2006
Revenues	**$ 49**	$ 230	**$ (566)**	$ 1,493
Expenses				
Operating	**(7)**	(1)	**(8)**	-
Depreciation, depletion and amortization	**21**	20	**39**	38
Segment Income (Loss)	**$ 35**	$ 211	**$ (597)**	$ 1,455
Administrative	**95**	75	**190**	133
Interest, net	**94**	83	**195**	171
Accretion of asset retirement obligation	**15**	12	**29**	24
Foreign exchange (gain) loss, net	**7**	(202)	**(5)**	(158)
(Gain) Loss on divestitures	**1**	(8)	**(58)**	(17)

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

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

($ millions)	Three Months Ended June 30 2007	Three Months Ended June 30 2006	Six Months Ended June 30 2007	Six Months Ended June 30 2006
Continuing Operations				
Natural Gas	**$ 71**	$ 195	**$ (484)**	$ 1,472
Crude Oil	**(22)**	35	**(82)**	21
	49	230	**(566)**	1,493
Expenses	**(6)**	-	**(7)**	2
	55	230	**(559)**	1,491
Income Tax Expense (Recovery)	**8**	69	**(183)**	515
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ 47**	$ 161	**$ (376)**	$ 976

Price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements and physical contracts. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. On June 30, 2007 the forward price curve for the remainder of 2007 for NYMEX gas decreased 2 percent from December 31, 2006 to $7.33 per Mcf while the forward price curve for WTI increased 7 percent to $71.23 per bbl.

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

Administrative expenses increased $20 million in the second quarter and $57 million for the six months ended June 30, 2007 compared to the same periods in 2006. The year-to-date increase was primarily due to higher long-term compensation expenses of $34 million as a result of the increase in the EnCana share price, higher salaries and other related expenses. Administrative expenses in the six months of 2007 were $0.25 per Mcfe compared with $0.17 per Mcfe in the same period in 2006.

Net interest expense in the six months of 2007 increased $24 million from the same period in 2006 as a result of higher outstanding debt. EnCana's total long-term debt, including current portion, increased $592 million to $7,426 million at June 30, 2007 compared with $6,834 at December 31, 2006. EnCana's 2007 and 2006 year-to-date weighted average interest rate on outstanding debt was 5.6 percent.

The foreign exchange gain of $5 million in the six months ended June 30, 2007 is due to the change in the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada and other gains offset by foreign exchange losses on the partnership contribution receivable. Under Canadian GAAP, EnCana is required to translate these items into Canadian dollars at the period-end exchange rate. Resulting unrealized foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings. Other foreign exchange gains and losses result from the settlement of foreign currency transactions and the translation of EnCana's monetary assets and liabilities.

The gain on divestitures in 2007 relates primarily to the divestiture of interests in Chad in the first quarter.

Income Tax

The effective tax rate for the six months ended June 30, 2007 is 22.0 percent compared to 23.0 percent for the equivalent period in 2006. The decrease reflects the effect of a Canadian federal corporate tax legislative change ($231 million) and a reduction of 0.5 percent in the Canadian federal corporate tax rate effective in 2011 ($37 million), both enacted in June 2007. The legislative change relates to phase-in of the deductibility of crown royalties which is now complete and will not recur in the future.

Cash taxes were $285 million in the second quarter of 2007 compared to $297 million in 2006. Cash taxes for the six months of 2007 were $660 million compared to $628 million in 2006. The increase of $32 million reflects increased U.S. taxes in 2007 offset by the cash tax benefit of the legislative change ($174 million) referred to above.

Further information regarding EnCana's effective tax rate can be found in Note 11 to the Interim Consolidated Financial Statements.

NET CAPITAL INVESTMENT

Capital Summary

($ millions)	Three Months Ended June 30 2007	Three Months Ended June 30 2006	Six Months Ended June 30 2007	Six Months Ended June 30 2006
Canada	**$ 591**	$ 778	**$ 1,462**	$ 1,907
United States	**422**	633	**861**	1,170
Other	**29**	21	**37**	39
Integrated Oilsands	**110**	175	**225**	395
Market Optimization	**2**	9	**3**	38
Corporate	**18**	16	**67**	29
Total Core Capital Investment	**1,172**	1,632	**2,655**	3,578
Acquisitions	**17**	271	**24**	286
Divestitures	**(165)**	(2)	**(446)**	(257)
Discontinued Operations	**-**	(1,072)	**-**	(2,415)
Net Capital Investment	**$ 1,024**	$ 829	**$ 2,233**	$ 1,192

EnCana's capital investment for the six months ended June 30, 2007 was funded by Cash Flow and debt.

Canada, United States and Other Capital Investment

Capital investment during the second quarter and six months of 2007 was primarily focused on continued development of our North American key resource plays.

The $756 million decrease in Canada, United States and Other core capital investment in the six months of 2007 compared to 2006 was primarily due to:

- A decrease of $445 million in Canada as a result of reduced drilling and completion activity in the Canadian Foothills Division due to weather related delays, lower drilling and completion costs resulting from increased efficiencies and lower facilities investment; and
- A decrease of $309 million in the U.S. primarily due to timing of capital investment in addition to lower drilling and completion costs resulting from increased efficiencies through the use of more fit-for-purpose rigs.

Integrated Oilsands Capital Investment

Capital investment during the second quarter and six months of 2007 was primarily focused on continued development of our Foster Creek and Christina Lake resource plays and on upgrades and coker projects at the Wood River and Borger refineries.

Corporate Capital Investment

Corporate capital investment in 2007 and 2006 include land purchases and costs related to the development of a Calgary office complex. On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of certain project assets and entered into a 25 year lease agreement with a third party developer. In addition, capital investment has been directed to business information systems and leasehold improvements.

Acquisitions, Divestitures and Discontinued Operations

Acquisitions included minor property acquisitions in 2007 and 2006 while divestitures included the sale of certain assets in the Mackenzie Delta and Beaufort Sea, interests in Chad and The Bow office project assets in 2007 and sale of the Entrega Pipeline in Colorado in 2006.

Included in Discontinued Operations is the divestiture of EnCana's Ecuador assets and gas storage business (discussed in Note 7 to the Interim Consolidated Financial Statements) in 2006 with the proceeds reduced by capital spending prior to the sale.

Liquidity and Capital Resources

($ millions)	Three Months Ended June 30 2007	Three Months Ended June 30 2006	Six Months Ended June 30 2007	Six Months Ended June 30 2006
Net Cash From (Used in)				
Operating activities	**$ 2,168**	$ 2,325	**$ 4,077**	$ 4,622
Investing activities	**(1,094)**	(1,166)	**(2,342)**	(1,363)
Financing activities	**(841)**	(1,230)	**(1,567)**	(3,111)
Foreign exchange loss on cash and cash equivalents held in foreign currency	**(15)**	-	**(15)**	-
Increase (decrease) in cash and cash equivalents	**$ 218**	$ (71)	**$ 153**	$ 148

Operating Activities

Cash Flow from Continuing Operations was $2,549 million during the second quarter of 2007 compared to $1,839 million for the same period in 2006. On a year-to-date basis Cash Flow from Continuing Operations was $4,301 million compared to $3,418 million for the same period in 2006. This increase was primarily due to increased revenues driven by U.S. refinery operations, higher realized financial commodity hedging gains, a cash tax recovery resulting from a Canadian federal corporate tax legislative change and natural gas production volumes partially reduced by lower natural gas prices and liquids production volumes and increased operating expenses. Cash Flow from Continuing Operations comprises most of EnCana's cash provided by operating activities.

Investing Activities

Net cash used for investing activities in the six months of 2007 increased $979 million compared to the same period in 2006. The 2006 investing activities were reduced by proceeds received from divestitures of the Ecuador assets in the first quarter ($1.4 billion) and the gas storage business in the second quarter ($1.3 billion). Capital expenditures, including property acquisitions, in the six months of 2007 decreased $1,185 million compared to the same period in 2006.

Financing Activities

Net issuance of long-term debt in the six months of 2007 was $394 million compared to net repayments of $982 million in 2006. EnCana's net debt adjusted for working capital was $7,342 million as at June 30, 2007 compared with $6,566 million as at December 31, 2006.

On May 24, 2007, EnCana filed 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. This shelf replaces EnCana's C$1.0 billion shelf prospectus which was fully drawn. EnCana had available unused committed bank credit facilities in the amount of $3.2 billion and unused capacity under shelf prospectuses, the availability of which is dependent upon market conditions, for up to $5.9 billion at June 30, 2007.

On March 12, 2007, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C$500 million. The notes have a coupon rate of 4.3 percent and mature on March 12, 2012. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor's Ratings Service has assigned a rating of A- with a 'Negative' outlook, DBRS Limited has assigned a rating of A(low) with a 'Stable' trend and Moody's Investors Service has assigned a rating of Baa2 with a 'Positive' outlook.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under five consecutive NCIBs. During the second quarter of 2007, EnCana purchased approximately 12 million of its Common Shares for total consideration of $713 million compared with 22.4 million Common Shares for total consideration of $1,095 million in 2006. During the six months of 2007, EnCana purchased 35.4 million of its Common Shares for total consideration of $1,807 million compared with 43.7 million Common Shares for total consideration of $2,073 million in 2006.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. EnCana doubled its quarterly dividend to 20 cents per share in the first quarter of 2007 and payments for the six months ended June 30, 2007 totaled $304 million. In the first quarter of 2006, EnCana paid a quarterly dividend of 7.5 cents per share. EnCana raised its quarterly dividend to 10 cents per share in the second quarter of 2006 and payments for the six months ended June 30, 2006 totaled $146 million. These dividends were funded by Cash Flow.

Financial Metrics

	June 30 2007	December 31 2006
Net Debt to Capitalization	**29%**	27%
Net Debt to Adjusted EBITDA (1)	**0.8x**	0.6x

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

Net Debt to Capitalization and Net Debt to Adjusted EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength. The increase in Net Debt to Capitalization ratio from December 31, 2006 results from the combination of higher long-term debt and a reduction in working capital, including the effect of lower risk management assets.

Free Cash Flow

EnCana's second quarter 2007 Free Cash Flow increased $1,194 million compared with the same period in 2006, which resulted from a combination of increased total Cash Flow and reduced capital investment.

	Three Months Ended June 30		Six Months Ended June 30		Year Ended
	2007	2006	**2007**	2006	2006
Cash Flow (1)	**$ 2,549**	$ 1,815	**$ 4,301**	$ 3,506	$ 7,161
Core Capital	**1,172**	1,632	**2,655**	3,578	6,269
Free Cash Flow (2)	**$ 1,377**	$ 183	**$ 1,646**	$ (72)	$ 892

(1) Cash Flow is a non-GAAP measure and is defined under "Cash Flow".

(2) Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of core capital investment.

Outstanding Share Data

(millions)	June 30 2007
Common Shares outstanding, beginning of year	**777.9**
Issued under option plans	**7.4**
Shares purchased	**(32.5)**
Common Shares outstanding, end of period	**752.8**
Weighted average Common Shares outstanding – diluted	**773.2**

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, 2007.

Employees and directors have been granted options to purchase Common Shares under various plans. At June 30, 2007, 4.3 million options without Tandem Share Appreciation Rights ("TSAR") attached were outstanding, all of which are exercisable.

Long-term incentives may be granted to EnCana employees in the form of stock options and Performance Share Units ("PSUs"). Additional information on these incentives is contained in Note 15 of the Company's audited Consolidated Financial Statements for the year ended December 31, 2006. During the first quarter of 2007, the vesting provisions for the 2004 granted PSUs were met and 2.9 million shares were distributed from the trust. At June 30, 2007, there were 2.6 million shares held in trust for distribution upon vesting of outstanding PSUs.

Contractual Obligations and Contingencies

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

Included in EnCana's total long-term debt commitments of $7,422 million at June 30, 2007 are $1,661 million in commitments related to Bankers' Acceptances and Commercial Paper. These amounts are fully supported and Management expects they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. Further details regarding EnCana's long-term debt are described in Note 14 to the Interim Consolidated Financial Statements.

As at June 30, 2007, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 38 MMcf/d with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 118 Bcf at a weighted average price of $4.06 per Mcf. At June 30, 2007, these transactions had an unrealized loss of $282 million.

Leases

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

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 antitrust and unfair competition laws.

Without admitting any liability in the lawsuits, WD concluded settlements of the class action lawsuits in both state and federal court, for $20.5 million and $2.4 million, respectively. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") for $20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against the outstanding claims; 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 that 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

As a result of the new joint venture with ConocoPhillips, EnCana has updated the following significant accounting policies and practices to incorporate the refining business.

- Revenue Recognition
- Inventory
- Property, Plant and Equipment
- Asset Retirement Obligation

All of these changes can be found in Note 3 to the Interim Consolidated Financial Statements.

New Accounting Standards Adopted

As disclosed in the year-end MD&A, on January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1530 "Comprehensive Income", Section 3251 "Equity", Section 3855 "Financial Instruments – Recognition and Measurement", and Section 3865 "Hedges". As required by the new standards, prior periods have not been restated, except to reclassify the foreign currency translation adjustment balance as described under Comprehensive Income. The adoption of these standards has had no material impact on the Company's Net Earnings or Cash Flows. Additional information on the effects of the implementation of the new standards can be found in Note 2 to the Interim Consolidated Financial Statements.

Recent Accounting Pronouncement

As of January 1, 2008, EnCana is required to adopt the CICA Section 3031 “Inventories”, which will replace the existing inventories standard. The new standard requires inventory to be valued on a first-in, first-out or weighted average basis. As EnCana’s inventory accounting policies are consistent with these requirements, the application of this standard will not have a material impact on the Consolidated Financial Statements.

Risk Management

EnCana’s results are affected by

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

EnCana takes a proactive approach in the identification and management of risks that can affect the Company. Mitigation of these risks include, but are not limited to, the use of derivative instruments, credit policies, operational policies, maintaining adequate insurance, environmental and safety policies as well as policies and enforcement procedures that can affect EnCana's reputation. Further discussion regarding the specific risks can be found in the December 31, 2006 Management's Discussion and Analysis.

Climate Change

The Canadian Federal Government (the “Federal Government”) has announced its intention to regulate greenhouse gases and other air pollutants. It is currently developing a framework that outlines its clean air and climate change action plan, including a target to reduce greenhouse gas (“GHG”) emissions and a commitment to regulate industry on an emissions intensity basis in the short term. Currently, the proposed legislation is under review, so there are few technical details regarding the implementation of the government’s plan, but they have made a commitment to work with industry to develop the specifics.

The Alberta Government has also passed legislation that will regulate GHG emissions from certain facilities located in the province. The Alberta Government’s legislation is called the *Climate Change and Emissions Management Act* (“CCEMA”). In March 2007, the Alberta Government proposed amendments to the CCEMA that starting on July 1, 2007 will require facilities that emit more than 100,000 tonnes of GHG per year to reduce their emissions intensity by 12 percent from a baseline established using an average emissions intensity calculated from reported emissions from 2003 - 2005. The companies that operate these facilities will be given options under the regulations to the CCEMA to allow them to comply with this requirement. These compliance options include making operating improvements, buying offsets to apply against their emission total or making contributions at C$15/tonne to a new Alberta Government fund that will invest in technology to reduce greenhouse gas emissions in the province.

As these 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 Corporation could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana, in cooperation with the Canadian Association of Petroleum Producers, will continue to work with the Federal Government and the Alberta Government to develop an approach to deal with climate change issues that protects the industry’s competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

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

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

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

Outlook

EnCana plans to continue its focus principally on growing natural gas and crude oil production from unconventional resource plays in North America and on developing its high quality in-situ oilsands resources and expanding the Company's downstream heavy oil processing capacity through its joint venture with ConocoPhillips.

Volatility in crude oil prices is expected to continue throughout 2007 as a result of market uncertainties over supply and refining disruptions, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies. Canadian crude prices will face added uncertainty due to the risk of refinery disruptions in an already tight US Midwest market and growing domestic production could result in pipeline constraints out of Western Canada.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that North American conventional gas supply has peaked in the past two years and that unconventional resource plays can at least partially offset conventional gas production declines. The industry's ability to respond to the constrained gas supply situation in North America remains challenged by land access and regulatory issues.

The Company expects its 2007 core capital investment program to be funded from Cash Flow.

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, as well as movements in foreign currency exchange rates and inflationary pressures on service costs.

Advisories

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this MD&A 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 MD&A include, but are not limited to, statements with respect to: projections with respect to growth of natural gas production from unconventional resource plays and in-situ oilsands resources; the expansion of the Company's downstream heavy oil processing capacity; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil prices in 2007 and beyond and the reasons therefor; the Company's projected capital investment levels for 2007 and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's defence of lawsuits; the impact of the climate change initiatives on operating costs; the adequacy of the Company's provision for taxes; 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; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to partially offset future conventional gas production declines. 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 reserve estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; the ability of the Company and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such 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 MD&A are made as of the date of this MD&A, 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 MD&A are expressly qualified by this cautionary statement.

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"). 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, Natural Gas Liquids and Natural Gas Conversions

In this MD&A, certain crude oil and natural gas liquids ("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 and Estimated Ultimate Recovery

EnCana uses the terms resource play and estimated ultimate recovery. 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. As used by EnCana, estimated ultimate recovery ("EUR") has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this MD&A and the Interim Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after-royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.89 for every Canadian dollar.

Non-GAAP Measures

Certain measures in this MD&A do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("Canadian GAAP") such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow per share-diluted, Free Cash Flow, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and Adjusted EBITDA 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 MD&A 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 MD&A as these measures are discussed and presented.

References to EnCana

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

ADDITIONAL INFORMATION

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

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*

($ millions, except per share amounts)		Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
REVENUES, NET OF ROYALTIES	*(Note 6)*				
Upstream		**$ 2,975**	$ 2,591	**$ 5,714**	$ 5,195
Integrated Oilsands		**1,867**	276	**3,423**	465
Market Optimization		**722**	825	**1,478**	1,541
Corporate - Unrealized gain (loss) on risk management		**49**	230	**(566)**	1,493
		5,613	3,922	**10,049**	8,694
EXPENSES	*(Note 6)*				
Production and mineral taxes		**57**	51	**149**	190
Transportation and selling		**234**	270	**512**	524
Operating		**565**	395	**1,116**	807
Purchased product		**1,836**	794	**3,687**	1,483
Depreciation, depletion and amortization		**899**	790	**1,742**	1,555
Administrative		**95**	75	**190**	133
Interest, net	*(Note 9)*	**94**	83	**195**	171
Accretion of asset retirement obligation	*(Note 15)*	**15**	12	**29**	24
Foreign exchange (gain) loss, net	*(Note 10)*	**7**	(202)	**(5)**	(158)
(Gain) loss on divestitures	*(Note 8)*	**1**	(8)	**(58)**	(17)
		3,803	2,260	**7,557**	4,712
NET EARNINGS BEFORE INCOME TAX		**1,810**	1,662	**2,492**	3,982
Income tax expense	*(Note 11)*	**364**	69	**549**	917
NET EARNINGS FROM CONTINUING OPERATIONS		**1,446**	1,593	**1,943**	3,065
NET EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 7)*	**-**	564	**-**	566
NET EARNINGS		**$ 1,446**	$ 2,157	**$ 1,943**	$ 3,631
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 18)*				
Basic		**$ 1.91**	$ 1.92	**$ 2.54**	$ 3.65
Diluted		**$ 1.89**	$ 1.88	**$ 2.51**	$ 3.58
NET EARNINGS PER COMMON SHARE	*(Note 18)*				
Basic		**$ 1.91**	$ 2.60	**$ 2.54**	$ 4.33
Diluted		**$ 1.89**	$ 2.55	**$ 2.51**	$ 4.24

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 11,344**	$ 9,481
Net Earnings		**1,943**	3,631
Dividends on Common Shares		**(304)**	(146)
Charges for Normal Course Issuer Bid	*(Note 16)*	**(1,421)**	(1,700)
RETAINED EARNINGS, END OF PERIOD		**$ 11,562**	$ 11,266

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME *(unaudited)*

($ millions)	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
NET EARNINGS	**$ 1,446**	$ 2,157	**$ 1,943**	$ 3,631
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Foreign Currency Translation Adjustment	**828**	444	**939**	538
COMPREHENSIVE INCOME	**$ 2,274**	$ 2,601	**$ 2,882**	$ 4,169

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

($ millions)	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
ACCUMULATED OTHER COMPREHENSIVE INCOME, BEGINNING OF YEAR	**$ 1,375**	$ 1,262
Foreign Currency Translation Adjustment	**939**	538
ACCUMULATED OTHER COMPREHENSIVE INCOME, END OF PERIOD	**$ 2,314**	$ 1,800

As at June 30, 2007, the accumulated other comprehensive income consists of foreign currency translation adjustments of $2,314 million (December 31, 2006 - $1,375 million; June 30, 2006 - $1,800 million).

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		As at June 30, 2007	As at December 31, 2006
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 555**	$ 402
Accounts receivable and accrued revenues		**2,244**	1,721
Current portion of partnership contribution receivable	*(Note 5, 12)*	**289**	-
Risk management	*(Note 19)*	**913**	1,403
Inventories	*(Note 13)*	**691**	176
		4,692	3,702
Property, Plant and Equipment, net	*(Note 6)*	**30,263**	28,213
Investments and Other Assets		**566**	533
Partnership Contribution Receivable	*(Note 5, 12)*	**3,297**	-
Risk Management	*(Note 19)*	**55**	133
Goodwill		**2,722**	2,525
	(Note 6)	**$ 41,595**	$ 35,106
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 3,526**	$ 2,494
Income tax payable		**749**	926
Current portion of partnership contribution payable	*(Note 5, 12)*	**280**	-
Risk management	*(Note 19)*	**53**	14
Current portion of long-term debt	*(Note 14)*	**471**	257
		5,079	3,691
Long-Term Debt	*(Note 14)*	**6,955**	6,577
Other Liabilities		**180**	79
Partnership Contribution Payable	*(Note 5, 12)*	**3,309**	-
Risk Management	*(Note 19)*	**13**	2
Asset Retirement Obligation	*(Note 15)*	**1,177**	1,051
Future Income Taxes		**6,477**	6,240
		23,190	17,640
Shareholders' Equity			
Share capital	*(Note 16)*	**4,472**	4,587
Paid in surplus		**57**	160
Retained earnings		**11,562**	11,344
Accumulated other comprehensive income		**2,314**	1,375
Total Shareholders' Equity		**18,405**	17,466
		$ 41,595	$ 35,106

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

($ millions)		Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 1,446**	$ 1,593	**$ 1,943**	$ 3,065
Depreciation, depletion and amortization		**899**	790	**1,742**	1,555
Future income taxes	*(Note 11)*	**79**	(228)	**(111)**	289
Unrealized (gain) loss on risk management	*(Note 19)*	**(55)**	(230)	**559**	(1,491)
Unrealized foreign exchange (gain) loss		**70**	(143)	**59**	(83)
Accretion of asset retirement obligation	*(Note 15)*	**15**	12	**29**	24
(Gain) loss on divestitures	*(Note 8)*	**1**	(8)	**(58)**	(17)
Other		**94**	53	**138**	76
Cash flow from discontinued operations		**-**	(24)	**-**	88
Net change in other assets and liabilities		**(16)**	38	**4**	27
Net change in non-cash working capital from continuing operations		**(365)**	1,508	**(228)**	3,552
Net change in non-cash working capital from discontinued operations		**-**	(1,036)	**-**	(2,463)
Cash From Operating Activities		**2,168**	2,325	**4,077**	4,622
INVESTING ACTIVITIES					
Capital expenditures	*(Note 6)*	**(1,189)**	(1,903)	**(2,679)**	(3,864)
Proceeds on disposal of assets	*(Note 8)*	**165**	2	**446**	257
Net change in investments and other		**(25)**	(59)	**(6)**	18
Net change in non-cash working capital from continuing operations		**(45)**	(270)	**(103)**	(151)
Discontinued operations		**-**	1,064	**-**	2,377
Cash (Used in) Investing Activities		**(1,094)**	(1,166)	**(2,342)**	(1,363)
FINANCING ACTIVITIES					
Net issuance (repayment) of revolving long-term debt		**(40)**	(101)	**(38)**	(982)
Issuance of long-term debt		**-**	-	**432**	-
Issuance of common shares	*(Note 16)*	**77**	49	**153**	101
Purchase of common shares	*(Note 16)*	**(713)**	(1,095)	**(1,807)**	(2,073)
Dividends on common shares		**(151)**	(82)	**(304)**	(146)
Other		**(14)**	(1)	**(3)**	(11)
Cash (Used in) Financing Activities		**(841)**	(1,230)	**(1,567)**	(3,111)
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**15**	-	**15**	-
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**218**	(71)	**153**	148
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**337**	324	**402**	105
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 555**	$ 253	**$ 555**	$ 253

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

1. BASIS OF PRESENTATION

The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. EnCana's continuing operations are in the business of exploration for, and production and marketing of natural gas, crude oil and natural gas liquids, 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, 2006, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2006.

2. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

As disclosed in the December 31, 2006 annual audited Consolidated Financial Statements, on January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (“CICA”) Handbook Section 1530 “Comprehensive Income”, Section 3251 “Equity”, Section 3855 “Financial Instruments – Recognition and Measurement”, and Section 3865 “Hedges”. As required by the new standards, prior periods have not been restated, except to reclassify the foreign currency translation adjustment balance as described under Comprehensive Income.

The adoption of these standards has had no material impact on the Company's net earnings or cash flows. The other effects of the implementation of the new standards are discussed below.

Comprehensive Income

The new standards introduce comprehensive income, which consists of net earnings and other comprehensive income (“OCI”). The Company's Consolidated Financial Statements now include a Statement of Comprehensive Income, which includes the components of comprehensive income. For EnCana, OCI is currently comprised of the changes in the foreign currency translation adjustment balance.

The cumulative changes in OCI are included in accumulated other comprehensive income (“AOCI”), which is presented as a new category within shareholders’ equity in the Consolidated Balance Sheet. The accumulated foreign currency translation adjustment, formerly presented as a separate category within shareholders’ equity, is now included in AOCI. The Company's Consolidated Financial Statements now include a Statement of Accumulated Other Comprehensive Income, which provides the continuity of the AOCI balance.

The adoption of comprehensive income has been made in accordance with the applicable transitional provisions. Accordingly, the June 30, 2007 period end accumulated foreign currency translation adjustment balance of $2,314 million has been reclassified to AOCI (December 31, 2006 - $1,375 million; June 30, 2006 - $1,800 million). In addition, the change in the accumulated foreign currency translation adjustment balance for the three months and six months ended June 30, 2007 of $828 million and $939 million, respectively, is now included in OCI in the Statement of Comprehensive Income (three months and six months ended June 30, 2006 - $444 million and $538 million, respectively).

Financial Instruments

The financial instruments standard establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the standard.

Financial assets and financial liabilities "held-for-trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available-for-sale" are measured at fair value, with changes in those fair values recognized in OCI. Financial assets "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization. The methods used by the Company in determining fair value of financial instruments are unchanged as a result of implementing the new standard.

Cash and cash equivalents are designated as "held-for-trading" and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Accounts receivable and accrued revenues and the partnership contribution receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, the partnership contribution payable and long-term debt are designated as "other financial liabilities".

The adoption of the financial instruments standard has been made in accordance with its transitional provisions. Accordingly, at January 1, 2007, $52 million of other assets were reclassified to long-term debt to reflect the adopted policy of capitalizing long-term debt transaction costs, premiums and discounts within long-term debt. The costs capitalized within long-term debt will be amortized using the effective interest method. Previously, the Company deferred these costs within other assets and amortized them straight-line over the life of the related long-term debt. The adoption of the effective interest method of amortization had no effect on opening retained earnings.

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Additional information on the Company's accounting treatment of derivative financial instruments is contained in Note 1 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2006.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. UPDATE TO ACCOUNTING POLICIES AND PRACTICES

As a result of the new joint venture with ConocoPhillips, EnCana has updated the following significant accounting policies and practices to incorporate the refining business (see Note 5):

Revenue Recognition

Revenues associated with the sales of EnCana's natural gas, crude oil, NGLs and petroleum and chemical products are recognized when title passes from the Company to its customer. Natural gas and crude oil produced and sold by EnCana below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue. Realized gains and losses from the Company's natural gas and crude oil commodity price risk management activities are recorded in revenue when the product is sold.

Market optimization revenues and purchased product are recorded on a gross basis when EnCana takes title to product and has risks and rewards of ownership. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis. Revenues associated with the services provided where EnCana acts as agent are recorded as the services are provided. Revenues associated with the sale of natural gas storage services are recognized when the services are provided. Sales of electric power are recognized when power is provided to the customer.

Unrealized gains and losses from the Company's natural gas and crude oil commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

Inventory

Product inventories, including petroleum and chemical products, are valued at the lower of average cost and net realizable value on a first-in, first-out basis. Materials and supplies are valued at cost.

Property, Plant and Equipment

Upstream

EnCana accounts for natural gas and crude oil properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the divestiture of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater, in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from the costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and
ii. the costs of unproved properties that have been subject to a separate impairment test.

Downstream Refining

Refining facilities are carried at cost, including asset retirement costs, and depreciated on a straight-line basis over the estimated service lives of the assets, which are approximately 25 years.

Midstream Facilities

Midstream facilities, including natural gas storage facilities, natural gas liquids extraction plant facilities and power generation facilities, are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 20 to 25 years. Capital assets related to pipelines are carried at cost and depreciated or amortized using the straight-line method over their economic lives, which range from 20 to 35 years.

Corporate

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 3 to 25 years. Assets under construction are not subject to depreciation. Land is carried at cost.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. UPDATE TO ACCOUNTING POLICIES AND PRACTICES (continued)

Asset Retirement Obligation

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made.

Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms, natural gas processing plants, and refining facilities. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs for natural gas and crude oil assets are amortized using the unit-of-production method. Asset retirement costs for refining facilities are amortized on a straight-line basis over the useful life of the related asset. Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

4. RECENT ACCOUNTING PRONOUNCEMENT

As of January 1, 2008, EnCana is required to adopt the CICA Section 3031 "Inventories", which will replace the existing inventories standard. The new standard requires inventory to be valued on a first-in, first-out or weighted average basis. As EnCana's inventory accounting policies are consistent with these requirements, the application of this standard will not have a material impact on the Consolidated Financial Statements.

5. JOINT VENTURE WITH CONOCOPHILLIPS

On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American heavy oil business with ConocoPhillips which consists of an upstream and a downstream entity. The upstream entity includes contributed assets from EnCana, primarily Foster Creek and Christina Lake oilsands properties, with a fair value of $7.5 billion and a note receivable from ConocoPhillips of an equal amount. For the downstream entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas respectively, for a fair value of $7.5 billion and EnCana contributed a note payable of $7.5 billion. Further information about these notes is included in Note 12.

In accordance with Canadian generally accepted accounting principles, these entities have been accounted for using the proportionate consolidation method with the results of operations shown in a separate business segment, Integrated Oilsands.

6. SEGMENTED INFORMATION

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

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

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

Operations that have been discontinued are disclosed in Note 7.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. SEGMENTED INFORMATION (continued)

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

	Upstream					
	Canada		United States		Other	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 1,829**	$ 1,758	**$ 1,059**	$ 766	**$ 87**	$ 67
Expenses						
Production and mineral taxes	**31**	24	**26**	27	**-**	-
Transportation and selling	**83**	78	**77**	52	**-**	-
Operating	**243**	208	**85**	75	**73**	50
Purchased product	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**524**	500	**275**	216	**6**	12
Segment Income	**$ 948**	$ 948	**$ 596**	$ 396	**$ 8**	$ 5

	Total Upstream		Integrated Oilsands		Market Optimization	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 2,975**	$ 2,591	**$ 1,867**	$ 276	**$ 722**	$ 825
Expenses						
Production and mineral taxes	**57**	51	**-**	-	**-**	-
Transportation and selling	**160**	130	**72**	130	**2**	10
Operating	**401**	333	**161**	50	**10**	13
Purchased product	**-**	-	**1,134**	-	**702**	794
Depreciation, depletion and amortization	**805**	728	**69**	40	**4**	2
Segment Income	**$ 1,552**	$ 1,349	**$ 431**	$ 56	**$ 4**	$ 6

	Corporate		Consolidated	
	2007	2006	**2007**	2006
Revenues, Net of Royalties	**$ 49**	$ 230	**$ 5,613**	$ 3,922
Expenses				
Production and mineral taxes	**-**	-	**57**	51
Transportation and selling	**-**	-	**234**	270
Operating	**(7)**	(1)	**565**	395
Purchased product	**-**	-	**1,836**	794
Depreciation, depletion and amortization	**21**	20	**899**	790
Segment Income	**$ 35**	$ 211	**2,022**	1,622
Administrative			**95**	75
Interest, net			**94**	83
Accretion of asset retirement obligation			**15**	12
Foreign exchange (gain) loss, net			**7**	(202)
(Gain) loss on divestitures			**1**	(8)
			212	(40)
Net Earnings Before Income Tax			**1,810**	1,662
Income tax expense			**364**	69
Net Earnings From Continuing Operations			**$ 1,446**	$ 1,593

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. SEGMENTED INFORMATION (continued)

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

Geographic and Product Information (Continuing Operations)

	Produced Gas					
	Canada		United States		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 1,446**	$ 1,296	**$ 989**	$ 695	**$ 2,435**	$ 1,991
Expenses						
Production and mineral taxes	**22**	15	**20**	23	**42**	38
Transportation and selling	**73**	71	**77**	52	**150**	123
Operating	**180**	153	**85**	75	**265**	228
Operating Cash Flow	**$ 1,171**	$ 1,057	**$ 807**	$ 545	**$ 1,978**	$ 1,602

	Oil & NGLs					
	Canada		United States		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 383**	$ 462	**$ 70**	$ 71	**$ 453**	$ 533
Expenses						
Production and mineral taxes	**9**	9	**6**	4	**15**	13
Transportation and selling	**10**	7	**-**	-	**10**	7
Operating	**63**	55	**-**	-	**63**	55
Operating Cash Flow	**$ 301**	$ 391	**$ 64**	$ 67	**$ 365**	$ 458

	Integrated Oilsands					
	Oil		Downstream Refining		Other	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 172**	$ 271	**$ 1,717**	$ -	**$ (22)**	$ 5
Expenses						
Transportation and selling	**72**	130	**-**	-	**-**	-
Operating	**39**	44	**119**	-	**3**	6
Purchased product	**-**	-	**1,157**	-	**(23)**	-
Operating Cash Flow	**$ 61**	$ 97	**$ 441**	$ -	**$ (2)**	$ (1)

	Integrated Oilsands	
	Total	
	2007	2006
Revenues, Net of Royalties	**$ 1,867**	$ 276
Expenses		
Transportation and selling	**72**	130
Operating	**161**	50
Purchased product	**1,134**	-
Operating Cash Flow	**$ 500**	$ 96

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. SEGMENTED INFORMATION (continued)

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

	Upstream					
	Canada		United States		Other	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 3,592**	$ 3,507	**$ 1,944**	$ 1,545	**$ 178**	$ 143
Expenses						
Production and mineral taxes	**59**	69	**90**	121	**-**	-
Transportation and selling	**163**	146	**143**	118	**-**	-
Operating	**480**	421	**160**	143	**154**	117
Purchased product	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**1,014**	990	**535**	426	**12**	19
Segment Income	**$ 1,876**	$ 1,881	**$ 1,016**	$ 737	**$ 12**	$ 7

	Total Upstream		Integrated Oilsands		Market Optimization	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 5,714**	$ 5,195	**$ 3,423**	$ 465	**$ 1,478**	$ 1,541
Expenses						
Production and mineral taxes	**149**	190	**-**	-	**-**	-
Transportation and selling	**306**	264	**196**	247	**10**	13
Operating	**794**	681	**313**	95	**17**	31
Purchased product	**-**	-	**2,253**	-	**1,434**	1,483
Depreciation, depletion and amortization	**1,561**	1,435	**135**	77	**7**	5
Segment Income	**$ 2,904**	$ 2,625	**$ 526**	$ 46	**$ 10**	$ 9

	Corporate		Consolidated	
	2007	2006	**2007**	2006
Revenues, Net of Royalties	**$ (566)**	$ 1,493	**$ 10,049**	$ 8,694
Expenses				
Production and mineral taxes	**-**	-	**149**	190
Transportation and selling	**-**	-	**512**	524
Operating	**(8)**	-	**1,116**	807
Purchased product	**-**	-	**3,687**	1,483
Depreciation, depletion and amortization	**39**	38	**1,742**	1,555
Segment Income (Loss)	**$ (597)**	$ 1,455	**2,843**	4,135
Administrative			**190**	133
Interest, net			**195**	171
Accretion of asset retirement obligation			**29**	24
Foreign exchange (gain) loss, net			**(5)**	(158)
(Gain) loss on divestitures			**(58)**	(17)
			351	153
Net Earnings Before Income Tax			**2,492**	3,982
Income tax expense			**549**	917
Net Earnings From Continuing Operations			**$ 1,943**	$ 3,065

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. SEGMENTED INFORMATION (continued)

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

Geographic and Product Information (Continuing Operations)

Produced Gas	Canada		United States		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 2,834**	$ 2,737	**$ 1,820**	$ 1,413	**$ 4,654**	$ 4,150
Expenses						
Production and mineral taxes	**42**	51	**78**	112	**120**	163
Transportation and selling	**143**	138	**143**	118	**286**	256
Operating	**357**	306	**160**	143	**517**	449
Operating Cash Flow	**$ 2,292**	$ 2,242	**$ 1,439**	$ 1,040	**$ 3,731**	$ 3,282

Oil & NGLs	Canada		United States		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 758**	$ 770	**$ 124**	$ 132	**$ 882**	$ 902
Expenses						
Production and mineral taxes	**17**	18	**12**	9	**29**	27
Transportation and selling	**20**	8	**-**	-	**20**	8
Operating	**123**	115	**-**	-	**123**	115
Operating Cash Flow	**$ 598**	$ 629	**$ 112**	$ 123	**$ 710**	$ 752

Integrated Oilsands	Oil		Downstream Refining		Other	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 392**	$ 454	**$ 3,060**	$ -	**$ (29)**	$ 11
Expenses						
Transportation and selling	**196**	247	**-**	-	**-**	-
Operating	**88**	82	**219**	-	**6**	13
Purchased product	**-**	-	**2,291**	-	**(38)**	-
Operating Cash Flow	**$ 108**	$ 125	**$ 550**	$ -	**$ 3**	$ (2)

Integrated Oilsands	Total	
	2007	2006
Revenues, Net of Royalties	**$ 3,423**	$ 465
Expenses		
Transportation and selling	**196**	247
Operating	**313**	95
Purchased product	**2,253**	-
Operating Cash Flow	**$ 661**	$ 123

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. SEGMENTED INFORMATION (continued)

Capital Expenditures (Continuing Operations)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	**2007**	2006
Core Capital				
Canada	**$ 591**	$ 778	**$ 1,462**	$ 1,907
United States	**422**	633	**861**	1,170
Other	**29**	21	**37**	39
Integrated Oilsands	**110**	175	**225**	395
Market Optimization	**2**	9	**3**	38
Corporate	**18**	16	**67**	29
	1,172	1,632	**2,655**	3,578
Acquisition Capital				
Canada	**-**	-	**7**	8
United States	**3**	250	**3**	257
Integrated Oilsands	**14**	21	**14**	21
	17	271	**24**	286
Total	**$ 1,189**	$ 1,903	**$ 2,679**	$ 3,864

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment As at		Total Assets As at	
	June 30, 2007	December 31, 2006	**June 30, 2007**	December 31, 2006
Canada	**$ 16,385**	$ 17,702	**$ 17,608**	$ 19,060
United States	**8,797**	8,494	**9,268**	9,036
Other	**147**	263	**226**	300
Integrated Oilsands	**4,432**	1,322	**9,392**	1,379
Market Optimization	**165**	154	**430**	468
Corporate	**337**	278	**4,671**	4,863
Total	**$ 30,263**	$ 28,213	**$ 41,595**	$ 35,106

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third party developer. Corporate Property, Plant and Equipment includes EnCana's accrual to date of $75 million related to this office project as an asset under construction. A corresponding liability is 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.

7. DISCONTINUED OPERATIONS

All of the sales of discontinued operations were completed as of December 31, 2006.

Midstream

During 2006, EnCana completed, in two separate transactions with a single purchaser, the sale of its natural gas storage operations in Canada and the United States. Total proceeds received were approximately $1.5 billion and an after-tax gain on sale of $829 million was recorded.

Ecuador

On February 28, 2006, EnCana completed the sale of its Ecuador operations for proceeds of $1.4 billion before indemnifications. A loss of $279 million, including the impact of indemnifications, was recorded. Indemnifications are discussed further in this note.

Amounts recorded as depreciation, depletion and amortization in 2006 represent provisions which were recorded against the net book value of the Ecuador operations to recognize Management’s best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian generally accepted accounting principles.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

7. DISCONTINUED OPERATIONS (continued)

Consolidated Statement of Earnings

The following table presents the effect of the discontinued operations in the Consolidated Statement of Earnings:

	For the three months ended June 30,							
	Ecuador		United Kingdom		Midstream		Total	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ -**	$ -	**$ -**	$ -	**$ -**	$ 28	**$ -**	$ 28
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**-**	-	**-**	-
Transportation and selling	**-**	-	**-**	-	**-**	-	**-**	-
Operating	**-**	-	**-**	-	**-**	10	**-**	10
Purchased product	**-**	-	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**-**	-	**-**	-	**-**	-	**-**	-
Interest, net	**-**	-	**-**	-	**-**	-	**-**	-
Foreign exchange (gain) loss, net	**-**	-	**-**	(1)	**-**	9	**-**	8
(Gain) loss on discontinuance	**-**	232	**-**	-	**-**	(768)	**-**	(536)
	-	232	**-**	(1)	**-**	(749)	**-**	(518)
Net Earnings (Loss) Before Income Tax	**-**	(232)	**-**	1	**-**	777	**-**	546
Income tax expense	**-**	-	**-**	2	**-**	(20)	**-**	(18)
Net Earnings (Loss) From Discontinued Operations	**$ -**	$ (232)	**$ -**	$ (1)	**$ -**	$ 797	**$ -**	$ 564

	For the six months ended June 30,							
	Ecuador		United Kingdom		Midstream		Total	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties *	**$ -**	$ 200	**$ -**	$ -	**$ -**	$ 463	**$ -**	$ 663
Expenses								
Production and mineral taxes	**-**	23	**-**	-	**-**	-	**-**	23
Transportation and selling	**-**	10	**-**	-	**-**	-	**-**	10
Operating	**-**	25	**-**	-	**-**	29	**-**	54
Purchased product	**-**	-	**-**	-	**-**	354	**-**	354
Depreciation, depletion and amortization	**-**	84	**-**	-	**-**	-	**-**	84
Interest, net	**-**	(2)	**-**	-	**-**	-	**-**	(2)
Foreign exchange (gain) loss, net	**-**	1	**-**	-	**-**	9	**-**	10
(Gain) loss on discontinuance	**-**	279	**-**	-	**-**	(768)	**-**	(489)
	-	420	**-**	-	**-**	(376)	**-**	44
Net Earnings (Loss) Before Income Tax	**-**	(220)	**-**	-	**-**	839	**-**	619
Income tax expense	**-**	59	**-**	2	**-**	(8)	**-**	53
Net Earnings (Loss) From Discontinued Operations	**$ -**	$ (279)	**$ -**	$ (2)	**$ -**	$ 847	**$ -**	$ 566

* Revenues, net of royalties in Ecuador for 2006 include realized losses of $1 million related to derivative financial instruments.

Contingencies

EnCana agreed to indemnify the purchaser of its Ecuador interests against losses that may arise in certain circumstances which are defined in the share sale agreements. The obligation to indemnify will arise should losses exceed amounts specified in the sale agreements and is limited to maximum amounts which are set forth in the share sale agreements.

During the second quarter of 2006, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator which is an event requiring indemnification under the terms of EnCana's sale agreement with the purchaser. The purchaser requested payment and EnCana paid the maximum amount in the third quarter, calculated in accordance with the terms of the agreements, of approximately $265 million. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

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

8. DIVESTITURES

Total year-to-date proceeds received on sale of assets and investments were $446 million (2006 - $257 million) as described below:

Canada and United States
In 2007, the Company has completed the divestiture of mature conventional oil and natural gas assets for proceeds of $23 million (2006 - $13 million).

Other
In May 2007, the Company completed the sale of certain assets in the Mackenzie Delta and Beaufort Sea for proceeds of $159 million.

In January 2007, the Company completed the sale of its interests in Chad, properties that are considered to be in the pre-production stage, for proceeds of $207 million which results in a gain on sale of $59 million.

Market Optimization
In February 2006, the Company sold its investment in Entrega Gas Pipeline LLC for approximately $244 million which resulted in a gain on sale of $17 million.

Corporate
In February 2007, the Company sold The Bow office project assets for proceeds of approximately $57 million, representing its investment at the date of sale. Refer to Note 6 for further discussion of The Bow office project assets.

9. INTEREST, NET

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	**2007**	2006
Interest Expense - Long-Term Debt	**$ 118**	$ 87	**$ 218**	$ 181
Interest Expense - Other *	**43**	5	**106**	10
Interest Income *	**(67)**	(9)	**(129)**	(20)
	$ 94	$ 83	**$ 195**	$ 171

* In 2007, Interest Expense - Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively. See Note 12.

10. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	**2007**	2006
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**$ (289)**	$ (163)	**$ (330)**	$ (159)
Translation of U.S. dollar partnership contribution receivable issued from Canada	**305**	-	**343**	-
Other Foreign Exchange (Gain) Loss	**(9)**	(39)	**(18)**	1
	$ 7	$ (202)	**$ (5)**	$ (158)

11. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	**2007**	2006
Current				
Canada	**$ 61**	$ 281	**$ 343**	$ 589
United States	**220**	13	**312**	36
Other Countries	**4**	3	**5**	3
Total Current Tax	**285**	297	**660**	628
Future	**79**	(228)	**(111)**	289
	$ 364	$ 69	**$ 549**	$ 917

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. INCOME TAXES (continued)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	**2007**	2006
Net Earnings Before Income Tax	**$ 1,810**	$ 1,662	**$ 2,492**	$ 3,982
Canadian Statutory Rate	**32.3%**	34.8%	**32.3%**	34.8%
Expected Income Tax	**585**	578	**805**	1,384
Effect on Taxes Resulting from:				
Non-deductible Canadian Crown payments	**-**	21	**-**	52
Canadian resource allowance	**-**	2	**-**	(18)
Statutory and other rate differences	**19**	(1)	**24**	(17)
Effect of tax rate changes *	**(37)**	(457)	**(37)**	(457)
Effect of legislative changes	**(231)**	-	**(231)**	-
Non-taxable downstream partnership income	**(13)**	-	**(19)**	-
Non-taxable capital (gains) losses	**8**	(32)	**(12)**	(33)
Large corporations tax	**-**	(1)	**-**	-
Other	**33**	(41)	**19**	6
	$ 364	$ 69	**$ 549**	$ 917
Effective Tax Rate	**20.1%**	4.2%	**22.0%**	23.0%

* The Canadian federal government, during the second quarters of 2007 and 2006, and the Alberta government, during the second quarter of 2006, enacted income tax rate changes.

12. PARTNERSHIP CONTRIBUTION RECEIVABLE / PAYABLE

Partnership Contribution Receivable

On January 2, 2007, upon the creation of the integrated oilsands joint venture, ConocoPhillips entered into a subscription agreement for a 50 percent interest in FCCL Oil Sands Partnership, the upstream entity, in exchange for a promissory note of $7.5 billion. The note bears interest at a rate of 5.3 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term partnership contribution receivable shown in the Consolidated Balance Sheet represent EnCana's 50 percent share of this promissory note.

Partnership Contribution Payable

On January 2, 2007, upon the creation of the integrated oilsands joint venture, EnCana issued a promissory note to WRB Refining LLC, the downstream entity, in the amount of $7.5 billion in exchange for a 50 percent interest. The note bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term partnership contribution payable amounts shown in the Consolidated Balance Sheet represent EnCana's 50 percent share of this promissory note.

13. INVENTORIES

	As at June 30, 2007	As at December 31, 2006
Product		
Canada	**$ -**	$ 42
Integrated Oilsands	**561**	8
Market Optimization	**130**	126
	$ 691	$ 176

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. LONG-TERM DEBT

	As at June 30, 2007	As at December 31, 2006
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	$ 1,336	$ 1,456
Unsecured notes	1,340	793
	2,676	2,249
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	325	104
Unsecured notes	4,421	4,421
	4,746	4,525
Increase in Value of Debt Acquired *	63	60
Debt Discounts and Financing Costs	(59)	-
Current Portion of Long-Term Debt	(471)	(257)
	$ 6,955	$ 6,577

* Certain of the notes and debentures of EnCana were acquired in business combinations and were accounted for at their fair value at the dates of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 21 years.

On March 12, 2007, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C$500 million. The notes have a coupon rate of 4.3 percent and mature on March 12, 2012.

15. 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, 2007	As at December 31, 2006
Asset Retirement Obligation, Beginning of Year	$ 1,051	$ 816
Liabilities Incurred	36	68
Liabilities Settled	(33)	(51)
Change in Estimated Future Cash Flows	4	172
Accretion Expense	29	50
Other	90	(4)
Asset Retirement Obligation, End of Period	$ 1,177	$ 1,051

16. SHARE CAPITAL

	June 30, 2007		December 31, 2006	
(millions)	Number	Amount	Number	Amount
Common Shares Outstanding, Beginning of Year	777.9	$ 4,587	854.9	$ 5,131
Common Shares Issued under Option Plans	7.4	153	8.6	179
Stock-based Compensation	-	12	-	11
Common Shares Purchased	(32.5)	(280)	(85.6)	(734)
Common Shares Outstanding, End of Period	752.8	$ 4,472	777.9	$ 4,587

Normal Course Issuer Bid

To June 30, 2007, the Company purchased 35.4 million Common Shares for total consideration of approximately $1,807 million. Of the amount paid, $304 million was charged to Share capital and $1,503 million was charged to Retained earnings. Included in the Common Shares Purchased in 2007 are 2.9 million Common Shares distributed, valued at $24 million, from the EnCana Employee Benefit Plan Trust that vested under EnCana's Performance Share Unit Plan (see Note 17). For these Common Shares distributed, there was an $82 million adjustment to Retained earnings with a reduction to Paid in surplus of $106 million.

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under five consecutive Normal Course Issuer Bids ("Bids"). EnCana is entitled to purchase, for cancellation, up to approximately 80.2 million Common Shares under the renewed Bid which commenced on November 6, 2006 and terminates on November 5, 2007.

Stock Options

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. SHARE CAPITAL (continued)

The following tables summarize the information about options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSARs") attached to them at June 30, 2007. Information related to TSARs is included in Note 17.

	Stock Options *(millions)*	Weighted Average Exercise Price *(C$)*
Outstanding, Beginning of Year	**11.8**	**23.17**
Exercised	**(7.4)**	**23.79**
Forfeited	**(0.1)**	**22.90**
Outstanding, End of Period	**4.3**	**22.13**
Exercisable, End of Period	**4.3**	**22.13**

	Outstanding Options			Exercisable Options	
Range of Exercise Price (C$)	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *(C$)*
11.00 to 16.99	0.6	2.3	11.58	0.6	11.58
17.00 to 22.99	0.1	0.9	22.54	0.1	22.54
23.00 to 23.99	3.3	0.8	23.88	3.3	23.88
24.00 to 24.99	0.2	0.9	24.43	0.2	24.43
25.00 to 25.99	0.1	1.2	25.62	0.1	25.62
	4.3	1.1	22.13	4.3	22.13

At June 30, 2007, the balance in Paid in surplus relates to stock-based compensation programs.

17. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at June 30, 2007. Additional information is contained in Note 15 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2006.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	**2007**	2006
Current Service Cost	**$ 4**	$ 4	**$ 8**	$ 7
Interest Cost	**5**	4	**9**	8
Expected Return on Plan Assets	**(5)**	(4)	**(9)**	(8)
Expected Actuarial Loss on Accrued Benefit Obligation	**1**	2	**2**	3
Expected Amortization of Past Service Costs	**1**	-	**1**	1
Amortization of Transitional Obligation	**(1)**	(1)	**(1)**	(1)
Expense for Defined Contribution Plan	**9**	6	**16**	11
Net Benefit Plan Expense	**$ 14**	$ 11	**$ 26**	$ 21

For the period ended June 30, 2007, contributions of $4 million have been made to the defined benefit pension plans (2006 - $6 million).

B) Share Appreciation Rights ("SARs")

The following table summarizes the information about SARs at June 30, 2007:

	Outstanding SARs	Weighted Average Exercise Price
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**2,088**	**14.21**
Exercised	**(2,088)**	**14.21**
Outstanding, End of Period	**-**	**-**
Exercisable, End of Period	**-**	**-**

For the period ended June 30, 2007, EnCana has not recorded any compensation costs related to the outstanding SARs (2006 - nil).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. COMPENSATION PLANS (continued)

C) Tandem Share Appreciation Rights ("TSARs")

The following table summarizes the information about TSARs at June 30, 2007:

	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**17,276,191**	**44.99**
Granted	**4,236,038**	**56.79**
Exercised - SARs	**(1,549,509)**	**40.96**
Exercised - Options	**(7,405)**	**39.82**
Forfeited	**(816,702)**	**42.42**
Outstanding, End of Period	**19,138,613**	**45.95**
Exercisable, End of Period	**5,337,229**	**42.60**

For the period ended June 30, 2007, EnCana recorded compensation costs of $157 million related to the outstanding TSARs (2006 - $58 million).

D) Performance-based Tandem Share Appreciation Rights ("Performance TSARs")

In 2007, under the terms of the existing Employee Stock Option Plan, EnCana granted Performance TSARs under which the employee has the right to receive a cash payment equal to the excess of the market price of EnCana Common Shares at the time of exercise over the grant price. Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to the Company attaining prescribed performance as measured by the annual recycle ratio. Performance TSARs vest proportionately for a recycle ratio of greater than one; the maximum number of Performance TSARs vest if the recycle ratio is three or greater.

The following table summarizes the information about Performance TSARs at June 30, 2007:

	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**-**	**-**
Granted	**7,275,575**	**56.09**
Forfeited	**(268,200)**	**56.09**
Outstanding, End of Period	**7,007,375**	**56.09**
Exercisable, End of Period	**-**	**-**

For the period ended June 30, 2007, EnCana recorded compensation costs of $9 million related to the outstanding Performance TSARs.

E) Deferred Share Units ("DSUs")

The following table summarizes the information about DSUs at June 30, 2007:

	Outstanding DSUs	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**866,577**	**29.56**
Granted, Directors	**77,081**	**56.80**
Exercised	**(334,615)**	**29.56**
Units, in Lieu of Dividends	**5,497**	**61.09**
Outstanding, End of Period	**614,540**	**33.26**
Exercisable, End of Period	**614,540**	**33.26**

For the period ended June 30, 2007, EnCana recorded compensation costs of $11 million related to the outstanding DSUs (2006 - $8 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. COMPENSATION PLANS (continued)

F) Performance Share Units ("PSUs")

The following table summarizes the information about PSUs at June 30, 2007:

	Outstanding PSUs	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**4,766,329**	**27.48**
Granted	**12,462**	**60.62**
Distributed	**(2,937,491)**	**24.05**
Forfeited	**(146,735)**	**33.74**
Outstanding, End of Period	**1,694,565**	**33.12**

For the period ended June 30, 2007, EnCana recorded compensation costs of $15 million related to the outstanding PSUs (2006 - reduction to compensation costs of $1 million).

At June 30, 2007, EnCana has approximately 2.6 million Common Shares held in trust for issuance upon vesting of the PSUs (2006 - 5.5 million).

18. 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)	2007	**2007**	2006	**2007**	2006
Weighted Average Common Shares Outstanding - Basic	768.4	**758.5**	829.6	**763.5**	838.7
Effect of Dilutive Securities	11.2	**6.7**	15.5	**9.7**	16.7
Weighted Average Common Shares Outstanding - Diluted	779.6	**765.2**	845.1	**773.2**	855.4

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

As a means of managing commodity price volatility, EnCana entered into various financial instrument agreements and physical contracts. The following information presents all positions for financial instruments.

Realized and Unrealized Gain (Loss) on Risk Management Activities

The following tables summarize the gains and losses on risk management activities:

	Realized Gain (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	**2007**	2006
Revenues, Net of Royalties	**$ 382**	$ 160	**$ 697**	$ (46)
Operating Expenses and Other	**-**	2	**1**	3
Gain (Loss) on Risk Management - Continuing Operations	**382**	162	**698**	(43)
Gain (Loss) on Risk Management - Discontinued Operations	**-**	3	**-**	4
	$ 382	$ 165	**$ 698**	$ (39)

	Unrealized Gain (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	**2007**	2006
Revenues, Net of Royalties	**$ 49**	$ 230	**$ (566)**	$ 1,493
Operating Expenses and Other	**6**	-	**7**	(2)
Gain (Loss) on Risk Management - Continuing Operations	**55**	230	**(559)**	1,491
Gain (Loss) on Risk Management - Discontinued Operations	**-**	(1)	**-**	22
	$ 55	$ 229	**$ (559)**	$ 1,513

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2007 to June 30, 2007:

	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	$ 1,416	$ -
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During 2007	132	132
Fair Value of Contracts in Place at Transition that Expired During 2007	-	7
Fair Value of Contracts Realized During 2007	(698)	(698)
Fair Value of Contracts Outstanding	$ 850	$ (559)
Paid Premiums on Unexpired Options	52	
Fair Value of Contracts and Premiums Paid, End of Period	$ 902	

At June 30, 2007, the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

	As at June 30, 2007
Risk Management	
Current asset	$ 913
Long-term asset	55
Current liability	53
Long-term liability	13
Net Risk Management Asset	$ 902

A summary of all unrealized estimated fair value financial positions is as follows:	As at June 30, 2007
Commodity Price Risk	
Natural gas	$ 930
Crude oil	(50)
Power	21
Interest Rate Risk	3
Credit Derivatives	(2)
Total Fair Value Positions	$ 902

Information with respect to credit derivatives and interest rate risk contracts in place at December 31, 2006 is disclosed in Note 16 to the Company's annual audited Consolidated Financial Statements.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Natural Gas

At June 30, 2007, the Company's gas risk management activities from financial contracts had an unrealized gain of $919 million and a fair market value position of $930 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	1,570	2007	8.63	US$/Mcf	$ 365
NYMEX Fixed Price	698	2008	8.56	US$/Mcf	68
Options					
Purchased NYMEX Put Options	240	2007	6.00	US$/Mcf	(3)
Basis Contracts					
Canada	747	2007	(0.72)	US$/Mcf	42
United States	912	2007	(0.70)	US$/Mcf	357
Canada	191	2008	(0.78)	US$/Mcf	9
United States	696	2008	(1.08)	US$/Mcf	74
United States	20	2009	(0.71)	US$/Mcf	3
Canada	41	2010	(0.40)	US$/Mcf	2
					917
Other Financial Positions *					2
Total Unrealized Gain on Financial Contracts					919
Paid Premiums on Unexpired Options					11
Total Fair Value Positions					$ 930

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

Crude Oil

At June 30, 2007, the Company's oil risk management activities from financial contracts had an unrealized loss of $91 million and a fair market value position of $(50) million. The contracts were as follows:

	Notional Volumes *(bbls/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
WTI NYMEX Fixed Price	34,500	2007	64.40	US$/bbl	$ (43)
WTI NYMEX Fixed Price	23,000	2008	70.13	US$/bbl	(18)
Options					
Purchased WTI NYMEX Put Options	91,500	2007	55.34	US$/bbl	(30)
					(91)
Other Financial Positions *					-
Total Unrealized Loss on Financial Contracts					(91)
Paid Premiums on Unexpired Options					41
Total Fair Value Positions					$ (50)

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

Power

The Company has in place two derivative contracts, commencing January 1, 2007 for a period of 11 years, to manage its electricity consumption costs. At June 30, 2007, these contracts had an unrealized gain of $21 million.

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

20. CONTINGENCIES

Legal Proceedings

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

Discontinued Merchant Energy Operations

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

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court, for payment, of $20.5 million and $2.4 million, respectively. Court approval of the federal court class action settlement of $2.4 million is pending, court approval having been granted in the state court action. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") for $20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against the outstanding claims; 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.

21. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2007.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)		2007			2006				
		Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
TOTAL CONSOLIDATED									
Cash Flow [(1)]		**4,301**	**2,549**	1,752	7,161	1,761	1,894	1,815	1,691
Per share	- Basic	**5.63**	**3.36**	2.28	8.73	2.22	2.34	2.19	1.99
	- Diluted	**5.56**	**3.33**	2.25	8.56	2.18	2.30	2.15	1.96
Net Earnings		**1,943**	**1,446**	497	5,652	663	1,358	2,157	1,474
Per share	- Basic	**2.54**	**1.91**	0.65	6.89	0.84	1.68	2.60	1.74
	- Diluted	**2.51**	**1.89**	0.64	6.76	0.82	1.65	2.55	1.70
Operating Earnings [(2)]		**2,234**	**1,376**	858	3,271	675	1,078	824	694
Per share	- Diluted	**2.89**	**1.80**	1.10	3.91	0.84	1.31	0.98	0.80
CONTINUING OPERATIONS									
Cash Flow from Continuing Operations [(3)]		**4,301**	**2,549**	1,752	7,043	1,742	1,883	1,839	1,579
Net Earnings from Continuing Operations		**1,943**	**1,446**	497	5,051	643	1,343	1,593	1,472
Per share	- Basic	**2.54**	**1.91**	0.65	6.16	0.81	1.66	1.92	1.74
	- Diluted	**2.51**	**1.89**	0.64	6.04	0.80	1.63	1.88	1.70
Operating Earnings - Continuing Operations [(4)]		**2,234**	**1,376**	858	3,237	672	1,064	841	660
Effective Tax Rates using									
Net Earnings		**22.0%**			27.3%				
Operating Earnings, excluding divestitures		**25.7%**			33.7%				
Canadian Statutory Rate		**32.3%**			34.7%				
Foreign Exchange Rates *(US$ per C$1)*									
Average		**0.881**	**0.911**	0.854	0.882	0.878	0.892	0.892	0.866
Period end		**0.940**	**0.940**	0.867	0.858	0.858	0.897	0.897	0.857
CASH FLOW INFORMATION									
Cash from Operating Activities		**4,077**	**2,168**	1,909	7,973	1,697	1,655	2,325	2,297
Deduct (Add back):									
Net change in other assets and liabilities		**4**	**(16)**	20	138	90	21	38	(11)
Net change in non-cash working capital from continuing operations		**(228)**	**(365)**	137	3,343	39	(247)	1,508	2,044
Net change in non-cash working capital from discontinued operations		**-**	**-**	-	(2,669)	(193)	(13)	(1,036)	(1,427)
Cash Flow [(1)]		**4,301**	**2,549**	1,752	7,161	1,761	1,894	1,815	1,691
Cash Flow from Discontinued Operations		**-**	**-**	-	118	19	11	(24)	112
Cash Flow from Continuing Operations [(3)]		**4,301**	**2,549**	1,752	7,043	1,742	1,883	1,839	1,579

(1) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, all 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 and the effect of a reduction in income tax rates.

(3) Cash Flow from Continuing Operations is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations, net change in non-cash working capital from discontinued operations and cash flow from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows.

(4) Operating Earnings - Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding the after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada and the effect of a reduction in income tax rates.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics (continued)

($ millions, except per share amounts)

Common Share Information	**2007**			2006				
	Year-to-date	**Q2**	**Q1**	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*								
Period end	**752.8**	**752.8**	**761.3**	777.9	777.9	800.1	815.8	836.2
Average - Basic	**763.5**	**758.5**	**768.4**	819.9	792.5	809.7	829.6	847.9
Average - Diluted	**773.2**	**765.2**	**779.6**	836.5	806.4	824.3	845.1	864.8
Price Range *($ per share)*								
TSX - C$								
High	**71.21**	**71.21**	**59.65**	62.52	61.90	62.52	59.38	57.10
Low	**51.55**	**57.61**	**51.55**	44.96	48.28	48.35	49.51	44.96
Close	**65.52**	**65.52**	**58.40**	53.66	53.66	52.01	58.78	54.50
NYSE - US$								
High	**66.87**	**66.87**	**51.49**	55.93	53.90	55.93	53.31	50.50
Low	**42.38**	**50.58**	**42.38**	39.54	42.75	43.32	44.02	39.54
Close	**61.45**	**61.45**	**50.63**	45.95	45.95	46.69	52.64	46.73
Dividends Paid *($ per share)*		**0.20**	**0.20**		0.10	0.10	0.10	0.075
Share Volume Traded *(millions)*	**658.7**	**327.4**	**331.3**	1,634.2	386.4	327.4	392.0	528.4
Share Value Traded *(US$ millions weekly average)*	**1,339.6**	**1,479.5**	**1,209.5**	1,516.2	1,447.9	1,272.9	1,484.8	1,850.5

Financial Metrics		
Net Debt to Capitalization	**29%**	27%
Net Debt to Adjusted EBITDA	**0.8x**	0.6x
Return on Capital Employed	**17%**	25%
Return on Common Equity	**22%**	34%

Net Capital Investment *($ millions)*	**2007**	2006
Core Capital		
Canada	**$ 1,462**	$ 1,907
United States	**861**	1,170
Other	**37**	39
Integrated Oilsands	**225**	395
Market Optimization	**3**	38
Corporate	**67**	29
Core Capital from Continuing Operations	**2,655**	3,578
Acquisitions		
Property		
Canada	**7**	8
United States	**3**	257
Integrated Oilsands	**14**	21
Divestitures		
Property		
Canada	**(12)**	(13)
United States	**(11)**	-
Other [(1)]	**(159)**	-
Corporate [(2)]	**(57)**	-
Corporate		
Market Optimization	**-**	(244)
Other [(3)]	**(207)**	-
Net Acquisition and Divestiture Activity from Continuing Operations	**(422)**	29
Discontinued Operations		
Ecuador	**-**	(1,116)
Midstream	**-**	(1,299)
Net Capital Investment	**$ 2,233**	$ 1,192

(1) Sale of Mackenzie Delta and Beaufort Sea assets closed May 30, 2007.
(2) Sale of EnCana's office building project assets, The Bow, closed February 9, 2007.
(3) Sale of interests in Chad closed January 12, 2007.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties

Production Volumes	**2007**			2006				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS								
Produced Gas *(MMcf/d)*								
Canada	**2,191**	**2,203**	2,178	2,185	2,205	2,162	2,192	2,182
United States	**1,263**	**1,303**	1,222	1,182	1,201	1,197	1,169	1,161
Total Produced Gas	**3,454**	**3,506**	3,400	3,367	3,406	3,359	3,361	3,343
Oil and Natural Gas Liquids *(bbls/d)*								
North America								
Light and Medium Oil	**40,980**	**40,025**	41,946	44,440	41,972	46,454	43,672	45,680
Heavy Oil - Foster Creek/Christina Lake	**25,645**	**27,994**	23,269	42,768	46,678	43,073	39,215	42,050
Heavy Oil - Other	**41,694**	**40,897**	42,500	45,858	41,913	43,287	44,572	53,822
Natural Gas Liquids [(1)]								
Canada	**10,859**	**11,017**	10,700	11,713	11,856	11,387	11,607	12,006
United States	**12,832**	**13,483**	12,175	12,494	12,250	12,520	12,793	12,415
Total Oil and Natural Gas Liquids	**132,010**	**133,416**	130,590	157,273	154,669	156,721	151,859	165,973
Total Continuing Operations *(MMcfe/d)*	**4,246**	**4,306**	4,184	4,311	4,334	4,299	4,272	4,339
DISCONTINUED OPERATIONS								
Ecuador *(bbls/d)*	**-**	**-**	-	11,996	-	-	-	48,650
Total Discontinued Operations *(MMcfe/d)*	**-**	**-**	-	72	-	-	-	292
Total *(MMcfe/d)*	**4,246**	**4,306**	4,184	4,383	4,334	4,299	4,272	4,631

(1) Natural gas liquids include condensate volumes.

Downstream			
Refinery Operations [(2)]			
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452
Crude oil runs *(Mbbls/d)*	**414**	**396**	433
Crude utilization *(%)*	**92%**	**88%**	96%
Refined products *(Mbbls/d)*	**439**	**421**	457

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

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2007			2006				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS								
Produced Gas - Canada *($/Mcf)*								
Price	**6.56**	**6.76**	6.36	6.20	5.87	5.59	5.71	7.66
Production and mineral taxes	**0.11**	**0.11**	0.10	0.10	0.05	0.09	0.08	0.18
Transportation and selling	**0.36**	**0.36**	0.36	0.35	0.33	0.37	0.35	0.34
Operating	**0.90**	**0.90**	0.91	0.79	0.82	0.78	0.77	0.79
Netback	**5.19**	**5.39**	4.99	4.96	4.67	4.35	4.51	6.35
Produced Gas - United States *($/Mcf)*								
Price	**5.97**	**5.73**	6.24	6.35	5.65	6.04	6.08	7.70
Production and mineral taxes	**0.34**	**0.17**	0.53	0.49	0.50	0.43	0.22	0.85
Transportation and selling	**0.63**	**0.65**	0.61	0.54	0.60	0.57	0.50	0.49
Operating	**0.69**	**0.71**	0.67	0.65	0.68	0.59	0.70	0.64
Netback	**4.31**	**4.20**	4.43	4.67	3.87	4.45	4.66	5.72
Produced Gas - Total *($/Mcf)*								
Price	**6.35**	**6.38**	6.32	6.25	5.79	5.75	5.84	7.68
Production and mineral taxes	**0.19**	**0.14**	0.26	0.24	0.21	0.21	0.13	0.41
Transportation and selling	**0.46**	**0.47**	0.45	0.42	0.42	0.44	0.40	0.40
Operating	**0.82**	**0.83**	0.82	0.74	0.77	0.71	0.74	0.74
Netback	**4.88**	**4.94**	4.79	4.85	4.39	4.39	4.57	6.13
Natural Gas Liquids - Canada *($/bbl)*								
Price	**49.35**	**55.21**	43.26	51.12	44.79	55.95	55.19	48.84
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**0.64**	**0.74**	0.54	0.67	0.58	0.74	0.73	0.61
Netback	**48.71**	**54.47**	42.72	50.45	44.21	55.21	54.46	48.23
Natural Gas Liquids - United States *($/bbl)*								
Price	**51.81**	**55.43**	47.77	56.33	51.04	61.76	58.25	54.07
Production and mineral taxes	**4.64**	**4.71**	4.56	4.19	4.62	4.42	2.60	5.18
Transportation and selling	**0.01**	**0.01**	0.01	0.01	0.01	0.01	0.01	0.01
Netback	**47.16**	**50.71**	43.20	52.13	46.41	57.33	55.64	48.88
Natural Gas Liquids - Total *($/bbl)*								
Price	**50.69**	**55.33**	45.66	53.81	47.97	58.99	56.80	51.50
Production and mineral taxes	**2.51**	**2.59**	2.43	2.16	2.35	2.31	1.36	2.63
Transportation and selling	**0.30**	**0.34**	0.26	0.33	0.29	0.36	0.35	0.31
Netback	**47.88**	**52.40**	42.97	51.32	45.33	56.32	55.09	48.56
Crude Oil - Light and Medium - *($/bbl)*								
Price	**49.86**	**53.36**	46.40	51.76	43.28	56.50	61.62	45.31
Production and mineral taxes	**2.17**	**2.19**	2.14	2.16	2.15	2.13	2.47	1.92
Transportation and selling	**1.39**	**1.36**	1.43	0.98	0.61	1.32	0.65	1.29
Operating	**9.14**	**9.28**	9.00	8.62	9.01	10.00	7.36	8.06
Netback	**37.16**	**40.53**	33.83	40.00	31.51	43.05	51.14	34.04
Crude Oil - Total - excluding Foster Creek/Christina Lake *($/bbl)*								
Price	**44.16**	**47.02**	41.42	44.83	37.65	51.37	55.58	35.39
Production and mineral taxes	**1.11**	**1.16**	1.06	1.11	1.11	1.14	1.28	0.92
Transportation and selling	**1.29**	**1.31**	1.27	0.91	0.60	1.27	0.76	1.00
Operating	**8.44**	**8.85**	8.06	7.69	8.59	8.73	6.84	6.67
Netback	**33.32**	**35.70**	31.03	35.12	27.35	40.23	46.70	26.80
Crude Oil - Heavy - Foster Creek/Christina Lake *($/bbl)*								
Price	**36.28**	**39.40**	33.28	36.49	39.32	37.19	46.53	23.08
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**3.33**	**3.62**	3.07	2.64	2.74	2.64	3.38	1.80
Operating (*)	**15.60**	**14.02**	17.12	12.38	13.07	14.06	11.78	10.39
Netback	**17.35**	**21.76**	13.09	21.47	23.51	20.49	31.37	10.89
Crude Oil - Total *($/bbl)*								
Price	**42.00**	**44.92**	39.19	41.83	36.94	48.74	51.62	30.76
Production and mineral taxes	**0.80**	**0.84**	0.77	0.77	0.74	0.81	0.88	0.66
Transportation and selling	**1.85**	**1.94**	1.75	1.40	1.11	1.74	1.54	1.24
Operating	**10.41**	**10.27**	10.54	9.09	10.05	10.20	8.34	7.82
Netback	**28.94**	**31.87**	26.13	30.57	25.04	35.99	40.86	21.04

(*) Q1 2007 includes a prior year under accrual of operating costs of approximately $1.82/bbl.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2007			2006				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS (continued)								
Total Liquids - Canada *($/bbl)*								
Price	**42.61**	**45.83**	39.50	42.53	37.55	49.21	51.91	32.17
Production and mineral taxes	**0.73**	**0.76**	0.70	0.70	0.67	0.73	0.80	0.61
Transportation and selling	**1.75**	**1.84**	1.67	1.35	1.06	1.67	1.48	1.19
Operating	**9.45**	**9.29**	9.60	8.33	9.21	9.39	7.63	7.17
Netback	**30.68**	**33.94**	27.53	32.15	26.61	37.42	42.00	23.20
Total Liquids *($/bbl)*								
Price	**43.50**	**46.81**	40.25	43.71	38.69	50.37	52.44	33.87
Production and mineral taxes	**1.10**	**1.16**	1.04	0.99	0.99	1.05	0.96	0.96
Transportation and selling	**1.58**	**1.65**	1.51	1.24	0.98	1.52	1.35	1.10
Operating	**8.61**	**8.41**	8.81	7.66	8.47	8.58	7.01	6.64
Netback	**32.21**	**35.59**	28.89	33.82	28.25	39.22	43.12	25.17
Total *($/Mcfe)*								
Price	**6.52**	**6.65**	6.40	6.48	5.93	6.31	6.46	7.22
Production and mineral taxes	**0.19**	**0.15**	0.24	0.22	0.20	0.20	0.13	0.36
Transportation and selling	**0.42**	**0.43**	0.42	0.37	0.37	0.40	0.36	0.35
Operating (1)	**0.94**	**0.93**	0.95	0.86	0.90	0.87	0.84	0.82
Netback	**4.97**	**5.14**	4.79	5.03	4.46	4.84	5.13	5.69

(1) Year-to-date operating costs include costs related to long-term incentives of $0.06/Mcfe (2006 - $0.02/Mcfe).

Impact of Realized Financial Hedging

	Year-to-date	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas *($/Mcf)*	**1.08**	**1.24**	0.92	0.47	0.91	0.82	0.66	(0.53)
Liquids *($/bbl)*	**0.52**	**(1.34)**	2.34	(3.32)	(3.30)	(3.45)	(3.43)	(3.12)
Total *($/Mcfe)*	**0.89**	**0.96**	0.82	0.25	0.60	0.53	0.40	(0.53)

Average Royalty Rates
(excluding impact of realized financial hedging)

	Year-to-date	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas								
Canada	**9.7%**	**9.1%**	10.3%	10.5%	9.9%	10.5%	10.4%	11.2%
United States	**19.1%**	**19.0%**	19.2%	18.5%	18.3%	18.4%	18.7%	18.7%
Crude Oil								
Canada	**12.2%**	**12.1%**	12.2%	9.9%	10.3%	11.4%	10.5%	7.5%
Natural Gas Liquids								
Canada	**17.3%**	**16.7%**	17.9%	15.5%	15.3%	16.3%	14.4%	16.1%
United States	**18.1%**	**17.7%**	18.5%	18.7%	18.8%	17.7%	20.1%	18.3%
Total	**13.3%**	**13.1%**	13.6%	13.0%	12.7%	13.2%	13.1%	12.9%

EnCana Corporation

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