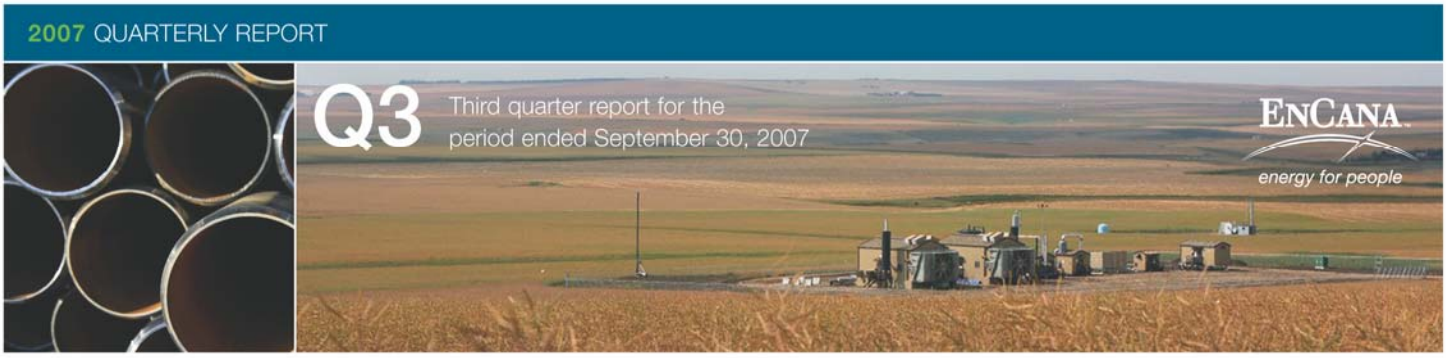

EnCana generates third quarter cash flow of US$2.2 billion, or $2.93 per share–up 27 percent

Net earnings per share down 25 percent to $1.24, or $934 million

Natural gas production increases 8 percent to 3.6 billion cubic feet per day

Calgary, Alberta, (October 25, 2007) – EnCana Corporation (TSX & NYSE: ECA) continued to generate solid cash flow during the third quarter of 2007 due to strong natural gas production growth and favourable gas price hedges that offset weaker gas prices, plus solid performance from the downstream segment of the company's integrated oilsands business.

"This strong performance is the result of the actions we have taken over the last several years to establish EnCana as a leading producer of unconventional natural gas and integrated in-situ oilsands, a company with a unique, low-risk, sustainable growth profile. Our financial and operating performance is on track for 2007, which is evidence that our resource play model is working extremely well. Natural gas production is up 16 percent per share, led by production from our key gas resource plays: Cutbank Ridge in northeast British Columbia, East Texas, Bighorn in west-central Alberta and Jonah in Wyoming. As well, we continue to expand our integrated oilsands business and capture value from strong refining margins in our downstream operations," said Randy Eresman, EnCana's President & Chief Executive Officer.

IMPORTANT NOTE: 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).

Third Quarter 2007 Highlights

(all comparisons are to the third quarter of 2006)

Financial – US$

- Cash flow per share diluted increased 27 percent to $2.93, or $2.2 billion
- Operating earnings per share diluted down 3 percent to $1.27, or $961 million, which is lower compared to the same quarter of 2006 in part due to a $255 million after-tax gain on the sale of a Brazil asset in the third quarter of 2006
- Net earnings per share diluted down 25 percent to $1.24, or $934 million
- Realized gains of $323 million, after tax, from commodity price risk management measures
- Integrated oilsands downstream business generated $344 million of pre-tax cash flow from U.S. refineries
- Capital investment up 7 percent to $1.58 billion
- Generated $643 million of free cash flow (as defined in Note 1 on page 7)
- Purchased approximately 3.5 million EnCana shares at an average price of $61.60 under the Normal Course Issuer Bid, completing the company's planned purchase of 5 percent of shares in 2007

Operating – Upstream

- Natural gas production increased 8 percent to 3.63 billion cubic feet per day (Bcf/d), up 16 percent per share
- Oil and natural gas liquids (NGLs) production up 1 percent on a pro forma basis to about 136,000 barrels per day (bbls/d), up 9 percent per share (see note 1, Production & Drilling Summary, page 3)
- Total natural gas and liquids production increased 7 percent on a pro forma basis to 4.45 billion cubic feet of gas equivalent per day (Bcfe/d), up 15 percent per share
- Key natural gas resource play production up 15 percent
- Oilsands production grew 33 percent to about 57,000 bbls/d (about 29,000 bbls/d net to EnCana) at Foster Creek and Christina Lake
- Operating and administrative costs of $1.01 per thousand cubic feet equivalent (Mcfe)

Operating – Downstream

- Refined products production averaged 484,000 bbls/d (242,000 bbls/d net to EnCana)
- Began processing Canadian bitumen blend through the Borger refinery in July, a major milestone for the refinery
- Refinery crude utilization of 102 percent was higher than the second quarter of 2007 due to the resumption of normal operations at the Borger refinery after the installation and start-up of the new coker in late June. Year-to-date utilization of 95 percent, or 430,000 bbls/d crude throughput (215,000 bbls/d net to EnCana), continues to exceed expectations due to record throughput at the Wood River refinery.

Natural gas production on track with 2007 forecast

Natural gas production in the third quarter rose steadily with strong year-over-year increases in a number of key resource plays – 47 percent in Cutbank Ridge, 36 percent in East Texas, 32 percent in Bighorn, 29 percent in Jonah and 22 percent in coalbed methane (CBM). Gas production to date in 2007 has averaged about 3.5 Bcf/d, in line with full-year guidance of 3.46 Bcf/d. Current production is about 3.6 Bcf/d. The company is on track to modestly exceed its full-year natural gas production guidance. EnCana expects it will likely achieve closer to 4 percent growth in gas production as opposed to its original 3 percent growth forecast.

Integrated oilsands business solid performance continues

The financial performance of EnCana's emerging integrated oilsands business continues to be strong. Regional and local market factors have an impact on refining crack spreads. EnCana's two refineries are located in markets influenced by U.S. Mid-continent and Chicago 3-2-1 crack spreads which have been strong relative to U.S. Gulf Coast and NYMEX crack spreads. Third quarter pre-tax cash flow from the integrated oilsands business was $411 million, composed of $344 million from downstream and $67 million from upstream. During the first nine months of 2007, the integrated oilsands business delivered more than $1 billion of pre-tax cash flow, about 14 percent of EnCana's total pre-tax cash flow.

"The financial and operating performance of our integrated oilsands business continues to validate our market integration initiatives," Eresman said. "The downstream performance also reflects the strength of ConocoPhillips' management and operating teams and their commitment and contribution to the success of this business venture."

Deep Panuke gas project off Nova Scotia moves ahead

EnCana's Board of Directors has sanctioned the development of the company's Deep Panuke natural gas project located about 175 kilometres offshore Nova Scotia. The $700 million project (about $550 million net to EnCana) is expected to start production in 2010 and is expected to deliver between 200 million and 300 million cubic feet of natural gas per day to markets in Canada and the northeast United States.

"Over the past five years, EnCana employees, the Government of Nova Scotia, federal and provincial regulators and the Atlantic energy community have worked diligently to achieve this important milestone. We are excited to move ahead with the development of the Deep Panuke discovery," Eresman said.

Financial Summary – Total Consolidated						
(for the period ended Sept 30) ($ millions, except per share amounts)	**Q3 2007**	Q3 2006	% Δ	**9 months 2007**	9 months 2006	% Δ
Cash flow[1]	**2,218**	1,894	+ 17	**6,519**	5,400	+ 21
Per share diluted	**2.93**	2.30	+ 27	**8.49**	6.39	+ 33
Operating earnings[1]	**961**	1,078	-11	**3,195**	2,596	+ 23
Per share diluted	**1.27**	1.31	- 3	**4.16**	3.07	+ 36
Net earnings	**934**	1,358	- 31	**2,877**	4,989	- 42
Per share diluted	**1.24**	1.65	- 25	**3.75**	5.90	- 36
Capital investment	**1,575**	1,474	+ 7	**4,230**	5,052	- 16
Earnings Reconciliation Summary – Total Consolidated						
Net earnings from continuing operations	**934**	1,343	- 30	**2,877**	4,408	- 35
Net earnings from discontinued operations	**-**	15	n/a	**-**	581	n/a
Net earnings (loss)	**934**	1,358	- 31	**2,877**	4,989	- 42
(Add back losses & deduct gains)						
Unrealized mark-to-market hedging gain (loss), after-tax	**(69)**	285	n/a	**(445)**	1,275	n/a
Unrealized foreign exchange gain (loss) on translation of U.S. dollar Notes issued from Canada, after-tax	**17**	(3)	n/a	**6**	128	n/a
Future tax recovery due to Canada and Alberta tax rate reductions	**-**	-	n/a	**37**	457	n/a
Gain (loss) on discontinuance, after-tax	**25**	(2)	n/a	**84**	533	n/a
Operating earnings[1]	**961**	1,078	- 11	**3,195**	2,596	+ 23
Per share diluted	**1.27**	1.31	- 3	**4.16**	3.07	+ 36

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 Sept 30) (After royalties)	**Q3 2007**	Q3 2006[1]	% Δ	**9 months 2007**	9 months 2006[1]	% Δ
Natural gas (MMcf/d)	**3,630**	3,359	+ 8	**3,513**	3,354	+ 5
Natural gas production per 1,000 shares (Mcf)	**445**	382	+16	**1,263**	1,100	+15
Oil and NGLs (Mbbls/d)	**136**	135	+ 1	**133**	153	- 13
Oil and NGLs production per 1,000 shares (Mcfe)	**100**	92	+9	**288**	302	- 5
Total Production (MMcfe/d)	**4,448**	4,170	+ 7	**4,314**	4,275	+ 1
Total per 1,000 shares (Mcfe)	**545**	474	+15	**1,551**	1,402	+ 11
Net wells drilled	**1,339**	1,001	+34	**3,171**	2,841	+12

1 2006 information has been adjusted on a pro forma basis to reflect the integrated oilsands transaction; the nine 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 15 percent from past year

Third quarter 2007 natural gas production from key resource plays increased 15 percent to 2.78 Bcf/d compared to 2.41 Bcf/d in the third quarter of 2006. This increased production was driven mainly by double-digit production increases in six of the company's nine gas resource plays, led by Cutbank Ridge in northeast British Columbia, East Texas, Bighorn in west-central Alberta, Jonah in Wyoming, the Barnett Shale play in the Fort Worth basin, and CBM in central and southern Alberta. The growth in Cutbank Ridge is the result of continued production growth from the Cadomin zone, along with an increasing contribution from the Montney and Doig formations. The increase in Jonah, EnCana's second largest resource play, can be attributed to improved response from frac stimulations and increased availability of capacity on regional pipelines due to system expansion and added compression on the gas gathering system.

Oilsands production from Foster Creek and Christina Lake was up 33 percent to about 57,000 bbls/d (about 29,000 bbls/d net to EnCana). Overall, third quarter gas and oil resource play production increased 15 percent in the past year, on a pro forma basis.

Growth from key North American resource plays

Resource Play	Daily Production									
	2007					2006				2005
(After royalties)	YTD	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural gas (MMcf/d)										
Jonah	**539**	**588**	523	504	464	487	455	450	461	435
Piceance	**346**	**354**	349	334	326	335	331	324	316	307
East Texas	**129**	**144**	139	103	99	95	106	93	99	90
Fort Worth	**119**	**128**	124	106	101	99	104	108	93	70
Greater Sierra	**208**	**220**	219	186	213	212	209	224	208	219
Cutbank Ridge	**227**	**245**	226	210	170	199	167	173	140	92
Bighorn	**116**	**128**	115	104	91	99	97	95	72	55
CBM [1]	**251**	**256**	245	251	194	211	209	179	177	112
Shallow Gas[2]	**725**	**713**	729	735	739	737	734	730	756	765
Total natural gas (MMcf/d)	**2,660**	**2,776**	2,669	2,533	2,397	2,474	2,412	2,376	2,322	2,145
Oil (Mbbls/d)										
Foster Creek[3]	**24**	**26**	25	20	18	21	19	16	18	14
Christina Lake[3]	**3**	**3**	3	3	3	3	3	3	3	3
Pelican Lake[4]	**23**	**24**	23	23	24	20	23	22	29	26
Total oil (Mbbls/d)	**50**	**53**	51	46	45	44	45	41	50	43
Total (MMcfe/d)	**2,959**	**3,090**	2,972	2,811	2,667	2,736	2,680	2,624	2,624	2,403
% change from Q3 2006		**15**								
% change from prior period		**4.0**	5.7	2.7	11	2.1	2.1	-	-2.9	

1 CBM volumes were restated in 2006 to account for commingled volumes from the coal and sand intervals based upon 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	Q3	Q2	Q1	Full year	Q4	Q3	Q2	Q1	Full Year
Natural gas										
Jonah	**112**	**31**	42	39	163	41	48	48	26	104
Piceance	**209**	**72**	72	65	220	50	48	59	63	266
East Texas	**27**	**9**	11	7	59	11	12	17	19	84
Fort Worth	**60**	**17**	29	14	97	19	22	27	29	59
Greater Sierra	**82**	**27**	32	23	115	5	16	34	60	164
Cutbank Ridge	**70**	**18**	25	27	116	19	35	36	26	135
Bighorn	**52**	**15**	9	28	52	7	7	18	20	51
CBM [1]	**749**	**323**	18	408	729	157	156	35	381	1,245
Shallow Gas[2]	**1,265**	**608**	241	416	1,310	389	475	217	229	1,389
Total gas wells	**2,626**	**1,120**	479	1,027	2,861	698	819	491	853	3,497
Oil										
Foster Creek[3]	**17**	**8**	1	8	3	-	-	-	3	20
Christina Lake[3]	**3**	**1**	2	-	1	-	-	-	1	-
Pelican Lake	**-**	**-**	-	-	-	-	-	-	-	52
Total oil wells	**20**	**9**	3	8	4	-	-	-	4	72
Total	**2,646**	**1,129**	482	1,035	2,865	698	819	491	857	3,569

1 CBM net wells drilled were restated in 2006 to account for commingled volumes from the coal and sand intervals based upon 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.

Third quarter 2007 natural gas and oil prices

	Q3 2007	Q3 2006	% Δ	9 months 2007	9 months 2006	% Δ
Natural gas						
($/Mcf, realized prices include hedging)						
NYMEX	6.16	6.58	- 6	6.83	7.45	- 8
EnCana Realized Gas Price	**6.75**	6.57	+3	**7.19**	6.74	+7
Oil and NGLs						
($/bbl, realized prices include hedging)						
WTI	75.15	70.54	+ 7	66.22	68.26	- 3
Western Canadian Select (WCS)	52.71	51.71	+ 2	46.86	46.55	+ 1
Differential WTI/WCS	22.44	18.83	+ 19	19.36	21.71	- 11
EnCana Realized Liquids Price	**49.01**	46.92	+4	**45.71**	42.03	+9
3-2-1 Crack Spread ($/bbl)						
U.S. Gulf Coast	11.74	11.00	+ 7	15.36	12.18	+ 26
U.S. Mid-Continent	20.92	17.75	+18	22.34	15.72	+42
Chicago	18.48	15.29	+21	20.50	14.67	+40

Price risk management
Risk management positions at September 30, 2007 are presented in Note 19 to the unaudited Interim Consolidated Financial Statements. In the third quarter of 2007, EnCana's commodity price risk management measures resulted in realized gains of approximately $323 million after-tax, composed of a $364 million gain on gas hedges and a $41 million loss on oil and other hedges.

About 1.1 Bcf/d of 2008 gas production hedged at $8.30 per Mcf
EnCana currently has fixed price contracts on about 1.1 Bcf/d of expected 2008 gas production at a NYMEX equivalent price of about $8.30 per Mcf. For the fourth quarter of 2007, EnCana has about 1.8 Bcf/d of gas production with downside price protection, composed of 1.6 Bcf/d under fixed price contracts at an average NYMEX equivalent price of $8.77 per Mcf and 240 MMcf/d with put options at a NYMEX equivalent strike price of $6.00 per Mcf. EnCana has hedged 23,000 bbls/d of expected 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.

U.S. Rockies and Canadian basis differential hedges
North American natural gas prices are impacted by volatile pricing disconnects caused primarily by transportation constraints between producing regions and consuming regions. EnCana's production gives rise to exposure to these price discounts, also known as basis differentials. For the remainder of 2007 EnCana has hedged 100 percent of its expected U.S. Rockies basis exposure using a combination of downstream transportation and basis hedges. The basis hedges have an effective annual average differential of NYMEX less 67 cents per Mcf. During the third quarter of 2007 the U.S. Rockies-NYMEX natural gas price differential averaged $3.22 per Mcf. For 2008, EnCana has hedged 100 percent of its expected U.S. Rockies basis exposure using a combination of downstream transportation and basis hedges, including some hedges that are based on a percentage of NYMEX prices. At the end of the third quarter, the basis hedges had an effective annual average differential of NYMEX less $1.01 per Mcf. In Canada for 2007, EnCana has hedged 33 percent of its expected AECO basis exposure at 72 cents per Mcf. EnCana has an additional 31 percent of expected Canadian basis exposure subject to transport and aggregator contracts. In the third quarter of 2007, the AECO basis differential averaged 84 cents per Mcf. In Canada for 2008, EnCana has hedged 8 percent of its expected production at an average AECO basis differential of 78 cents per Mcf. During the third quarter of 2007, EnCana's basis hedging resulted in a realized gain before tax of about $255 million.

Corporate developments

Alberta Royalty Review
The Government of Alberta is in the midst of a comprehensive review of the province's oil and natural gas royalty structure. Until detailed and specific information of any royalty changes is outlined publicly and thoroughly evaluated by the company, EnCana is unable to comment on how potential changes may impact the company's operations.

Columbia River Basin
EnCana has concluded its exploration program in the Columbia River Basin in Washington state after drilling three wells, Anderville Farms Inc. #1, Anderson 11-5, and Brown 7-24. Each well indicated the presence of natural gas. Although commercial flow rates were not established in these wells, there remains potential for large natural gas accumulations in the basin, which has only been partially tested. Exxel Energy Corp. took over operatorship and ownership of the Brown well in late September and is planning to conduct

additional completion testing on the well. Because this is a non-core play for EnCana, the company anticipates that any future activities on EnCana's acreage position will likely be funded by third-party capital under farm-in or similar arrangements. As a result, EnCana has no immediate plans for additional drilling.

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 December 31, 2007 to common shareholders of record as of December 14, 2007.

Normal Course Issuer Bid
In the past 12 months under its Normal Course Issuer Bid, EnCana purchased 63.4 million common shares, representing approximately 7.9 percent of the company's outstanding shares on November 1, 2006, at an average price of approximately US$51.54 per common share.

Financial strength

EnCana maintains a strong balance sheet, targeting a net debt-to-capitalization ratio between 30 and 40 percent. At September 30, 2007, the company's net debt-to-capitalization ratio was 27:73. At the end of the third quarter EnCana's net debt-to-adjusted-EBITDA multiple, on a trailing 12-month basis, was 0.8 times. The company expects its net debt-to-capitalization ratio to remain at the lower end of the targeted range.

In the third quarter of 2007, EnCana invested $1,575 million in capital. Net acquisitions were $16 million, resulting in net capital investment in continuing operations of $1,591 million.

NOTE 1: Non-GAAP measures
This interim report contains references to cash flow, pre-tax 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.
- Pre-tax cash flow is calculated as cash flow before cash taxes.
- Operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain/loss on discontinuance, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated 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 total capital investment and is used to determine the funds available for other investing and/or financing activities.

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; the anticipated production, timing thereof, and expenditures associated with the Deep Panuke Project; anticipated potential of and third party capital for the Columbia River Basin; 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 Borger and Wood River 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 royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the company operates; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.

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 September 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 volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated October 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 Atlantic Canada, the Middle East and France.
- Integrated Oilsands is focused on two lines of business: the exploration for, and development and production of heavy oil from oil sands 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 third quarter of 2007 compared to the third quarter of 2006, EnCana:

- Reported an 18 percent increase in Cash Flow from Continuing Operations to $2,218 million primarily due to $344 million of Operating Cash Flow from U.S. refinery operations;
- Reported a 10 percent decrease in Operating Earnings from Continuing Operations to $961 million primarily due to the sale of interests in Brazil in 2006;
- Reported a 30 percent decrease in Net Earnings from Continuing Operations to $934 million primarily due to after-tax unrealized mark-to-market losses in 2007 compared with gains in 2006 and the Brazil divestiture noted above;
- Reported a 53 percent increase in Free Cash Flow to $643 million;
- Grew natural gas production 8 percent to 3,630 million cubic feet ("MMcf") of gas per day ("MMcf/d");
- Increased production from natural gas key resource plays 15 percent;
- Grew crude oil production 33 percent at Foster Creek and Christina Lake to 57,480 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 33 percent to 28,740 bbls/d;
- Reported an 11 percent decrease in natural gas prices to $5.10 per thousand cubic feet ("Mcf"). Realized natural gas prices, including the impact of financial hedging, averaged $6.75 per Mcf, an increase of 3 percent;
- Completed the sale of assets in Australia for proceeds of $31 million and recorded a gain of $30 million before-tax ($25 million after-tax);
- Announced an agreement to sell its remaining interests in Brazil for approximately $165 million plus closing adjustments. The sale is subject to closing conditions and regulatory approvals and will be recorded on closing which is expected to occur in the first quarter of 2008; and
- Purchased approximately 3.5 million of its Common Shares at an average price of $61.60 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of $218 million in the third quarter of 2007.

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

- Reported a 23 percent increase in Cash Flow from Continuing Operations to $6,519 million primarily due to $894 million of Operating Cash Flow from U.S. refinery operations;
- Reported a 25 percent increase in Operating Earnings from Continuing Operations to $3,195 million primarily due to U.S. refinery operations offset by lower Operating Cash Flow from Foster Creek and Christina Lake;
- Reported a 35 percent decrease in Net Earnings from Continuing Operations to $2,877 million primarily due to after-tax unrealized mark-to-market losses in 2007 compared with gains in 2006, the sale of interests in Brazil in 2006 and a significant future tax recovery resulting from tax rate reductions in 2006;
- Reported a $1,941 million increase in Free Cash Flow to $2,289 million;
- Grew natural gas production 5 percent to 3,513 MMcf/d;
- Increased production from natural gas key resource plays 12 percent;
- Grew crude oil production 29 percent at Foster Creek and Christina Lake to 53,376 bbls/d. After reflecting the 50 percent contribution to the joint venture with ConocoPhillips, EnCana's reported production from these two properties decreased 36 percent to 26,688 bbls/d;
- Reported an 8 percent decrease in natural gas prices to $5.91 per Mcf. Realized natural gas prices, including the impact of financial hedging, averaged $7.19 per Mcf, an increase of 7 percent;
- Completed the sale of assets in Australia for $31 million, certain assets in the Mackenzie Delta and Beaufort Sea for $159 million and interests in Chad for $208 million;
- Announced an agreement to sell its remaining interests in Brazil for approximately $165 million plus closing adjustments. The sale is subject to closing conditions and regulatory approvals and will be recorded on closing which is expected to occur in the first quarter of 2008; and
- Purchased 38.9 million of its Common Shares at an average price of $52.05 per share under the NCIB for a total cost of $2,025 million in 2007;
- Increased its quarterly dividend to 20 cents per share in 2007 compared to 7.5 cents per share in the first quarter of 2006 and 10 cents per share in the second and third quarters of 2006; 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 to assist in understanding EnCana's financial results:

	Three Months Ended September 30			Nine Months Ended September 30		
		2007 vs			2007 vs	
(Average for the period)	**2007**	**2006**	2006	**2007**	**2006**	2006
Natural Gas Price Benchmarks						
AECO Price *(C$/Mcf)*	**$ 5.61**	**-7%**	$ 6.03	**$ 6.81**	**-5%**	$ 7.19
NYMEX Price *($/MMBtu)*	**6.16**	**-6%**	6.58	**6.83**	**-8%**	7.45
Rockies (Opal) Price *($/MMBtu)*	**2.94**	**-45%**	5.30	**4.11**	**-31%**	5.95
Texas (HSC) Price *($/MMBtu)*	**5.89**	**-4%**	6.14	**6.56**	**-2%**	6.71
Basis Differential *($/MMBtu)*						
AECO/NYMEX	**0.84**	**-29%**	1.18	**0.71**	**-35%**	1.10
Rockies/NYMEX	**3.22**	**152%**	1.28	**2.71**	**81%**	1.50
Texas/NYMEX	**0.27**	**-39%**	0.44	**0.27**	**-63%**	0.73
Crude Oil Price Benchmarks						
WTI *($/bbl)*	**75.15**	**7%**	70.54	**66.22**	**-3%**	68.26
WCS *($/bbl)*	**52.71**	**2%**	51.71	**46.86**	**1%**	46.55
Differential - WTI/WCS *($/bbl)*	**22.44**	**19%**	18.83	**19.36**	**-11%**	21.71
USGC 3-2-1 Crack Spread *($/bbl)* [(1)]	**11.74**	**7%**	11.00	**15.36**	**26%**	12.18
Foreign Exchange						
U.S./Canadian Dollar Exchange Rate	**0.957**	**7%**	0.892	**0.905**	**2%**	0.883

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

Acquisitions and Divestitures

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

- The sale of assets in Australia on August 15 for $31 million resulting in a gain on sale of $30 million before-tax ($25 million after-tax);
- The sale of certain assets in the Mackenzie Delta and Beaufort Sea on May 30 for $159 million; and
- The sale of its interests in Chad on January 12 for $208 million resulting in a gain on sale of $59 million.

On September 13, EnCana announced that it had reached an agreement to sell its interests in Brazil for approximately $165 million plus closing adjustments. The sale is subject to closing conditions and regulatory approvals and will be recorded on closing which is expected to occur in the first quarter of 2008.

In addition to these 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

	Nine Months Ended Sept 30		**2007**			2006				2005
($ millions, except per share amounts)	**2007**	2006	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Total Consolidated										
Cash Flow [1]	**$ 6,519**	$ 5,400	**$ 2,218**	$ 2,549	$ 1,752	$ 1,761	$ 1,894	$ 1,815	$ 1,691	$ 2,510
- per share – diluted	**8.49**	6.39	**2.93**	3.33	2.25	2.18	2.30	2.15	1.96	2.88
Net Earnings	**2,877**	4,989	**934**	1,446	497	663	1,358	2,157	1,474	2,366
- per share – basic	**3.79**	6.02	**1.24**	1.91	0.65	0.84	1.68	2.60	1.74	2.77
- per share – diluted	**3.75**	5.90	**1.24**	1.89	0.64	0.82	1.65	2.55	1.70	2.71
Operating Earnings [2]	**3,195**	2,596	**961**	1,376	858	675	1,078	824	694	1,271
- per share – diluted	**4.16**	3.07	**1.27**	1.80	1.10	0.84	1.31	0.98	0.80	1.46
Continuing Operations										
Cash Flow from Continuing Operations [1]	**6,519**	5,301	**2,218**	2,549	1,752	1,742	1,883	1,839	1,579	2,390
Net Earnings from Continuing Operations	**2,877**	4,408	**934**	1,446	497	643	1,343	1,593	1,472	1,869
- per share – basic	**3.79**	5.32	**1.24**	1.91	0.65	0.81	1.66	1.92	1.74	2.19
- per share – diluted	**3.75**	5.21	**1.24**	1.89	0.64	0.80	1.63	1.88	1.70	2.14
Operating Earnings from Continuing Operations [2]	**3,195**	2,565	**961**	1,376	858	672	1,064	841	660	1,229
Revenues, Net of Royalties	**15,645**	12,723	**5,596**	5,613	4,436	3,676	4,029	3,922	4,772	5,933

[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 September 30, 2007 versus 2006

Cash Flow from Continuing Operations in the third quarter of 2007 increased $335 million or 18 percent compared to the third quarter of 2006.

The increase in Cash Flow from Continuing Operations resulted from:

- Operating Cash Flow from U.S. refinery operations was $344 million in 2007 with no comparative amount in 2006;
- Realized financial natural gas, crude oil and other commodity hedging gains were $323 million after-tax in 2007 compared with gains of $133 million after-tax in 2006;
- Natural gas production volumes in 2007 increased 8 percent to 3,630 MMcf/d from 3,359 MMcf/d in 2006; and
- Average North American liquids prices, excluding financial hedges, increased 6 percent to $53.37 per bbl in 2007 compared to $50.37 per bbl in 2006.

Cash Flow from Continuing Operations was reduced by:

- Average North American natural gas prices, excluding financial hedges, decreased 11 percent to $5.10 per Mcf in 2007 compared to $5.75 per Mcf in 2006; and
- North American liquids production volumes in 2007 decreased 13 percent to 136,383 bbls/d from 156,721 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.

Nine Months Ended September 30, 2007 versus 2006

Cash Flow from Continuing Operations in the nine months of 2007 increased $1,218 million or 23 percent compared to 2006.

The increase in Cash Flow from Continuing Operations resulted from:

- Operating Cash Flow from U.S. refinery operations was $894 million in 2007 with no comparative amount in 2006;
- Realized financial natural gas, crude oil and other commodity hedging gains were $777 million after-tax in 2007 compared with gains of $103 million after-tax in 2006;
- Natural gas production volumes in 2007 increased 5 percent to 3,513 MMcf/d from 3,354 MMcf/d in 2006;
- Average North American liquids prices, excluding financial hedges, increased 3 percent to $46.84 per bbl in 2007 compared to $45.36 per bbl in 2006; and

Cash Flow from Continuing Operations was reduced by:

- North American liquids production volumes in 2007 decreased 16 percent to 133,485 bbls/d from 158,152 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;
- Average North American natural gas prices, excluding financial hedges, decreased 8 percent to $5.91 per Mcf in 2007 compared to $6.41 per Mcf in 2006; and
- Cash taxes increased 17 percent to $974 million due to higher U.S. taxes arising from refinery operations offset by the cash tax benefit of a Canadian federal corporate tax legislative change.

NET EARNINGS

Three Months Ended September 30, 2007 versus 2006

EnCana's third quarter 2007 Net Earnings were $424 million lower compared to 2006.

EnCana's third quarter 2007 Net Earnings from Continuing Operations were $409 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 $69 million after-tax in 2007 compared with gains of $282 million after-tax in 2006;
- A gain on sale of approximately $25 million after-tax from the sale of assets in Australia compared with a $255 million after-tax gain on sale of interests in Brazil in 2006;
- Depreciation, depletion and amortization ("DD&A") of $988 million in 2007 compared to $791 million in 2006;
- Foreign exchange losses of $76 million after-tax in 2007 compared with gains of $1 million after-tax in 2006; and

Nine Months Ended September 30, 2007 versus 2006

EnCana's nine months 2007 Net Earnings were $2,112 million lower compared to 2006 due to a net gain of $533 million after-tax on sale of the gas storage business and Ecuador assets in 2006 and the items discussed below.

EnCana's nine months 2007 Net Earnings from Continuing Operations were $1,531 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 $445 million after-tax in 2007 compared with gains of $1,258 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;
- DD&A of $2,730 million in 2007 compared to $2,346 million in 2006;
- Foreign exchange losses of $55 million after-tax in 2007 compared with gains of $111 million after-tax in 2006; and
- A 2007 gain on sale of approximately $25 million after-tax from the sale of assets in Australia and approximately $59 million after-tax from the sale of interests in Chad compared with a $255 million after-tax gain on sale of interests in Brazil 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 September 30				Nine Months Ended September 30			
	2007		2006		**2007**		2006	
($ millions, except per share amounts)		**Per share[5]**		Per share[5]		**Per share[5]**		Per share[5]
Net Earnings, as reported	**$ 934**	**$ 1.24**	$ 1,358	$ 1.65	**$ 2,877**	**$ 3.75**	$ 4,989	$ 5.90
Add back (losses) and deduct gains:								
- Unrealized mark-to-market accounting gain (loss), after-tax	**(69)**	**(0.09)**	285	0.34	**(445)**	**(0.58)**	1,275	1.51
- Unrealized foreign exchange gain (loss), after-tax [1]	**17**	**0.03**	(3)	-	**6**	**0.01**	128	0.15
- Gain (loss) on discontinuance, after-tax [2]	**25**	**0.03**	(2)	-	**84**	**0.11**	533	0.63
- Future tax recovery due to tax rate reductions	**-**	**-**	-	-	**37**	**0.05**	457	0.54
Operating Earnings [3] [4]	**$ 961**	**$ 1.27**	$ 1,078	$ 1.31	**$ 3,195**	**$ 4.16**	$ 2,596	$ 3.07

(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 U.S. dollar debt issued from Canada have maturity dates in excess of five years.

(2) Sale of Australia assets and sale of storage facilities for the three months ended September 30, 2007 and 2006, respectively; sale of Australia assets and interests in Chad for the nine months ended September 30, 2007; sale of storage facilities and sale of interests in Ecuador for the nine months ended September 30, 2006.

(3) 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.

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

(5) Per Common Share – diluted.

Summary of Operating Earnings from Continuing Operations

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Net Earnings from Continuing Operations, as reported	**$ 934**	$ 1,343	**$ 2,877**	$ 4,408
Add back (losses) and deduct gains:				
- Unrealized mark-to-market accounting gain (loss), after-tax	**(69)**	282	**(445)**	1,258
- Unrealized foreign exchange gain (loss), after-tax [1]	**17**	(3)	**6**	128
- Gain (loss) on discontinuance, after-tax [2]	**25**	-	**84**	-
- Future tax recovery due to tax rate reductions	**-**	-	**37**	457
Operating Earnings from Continuing Operations [3] [4]	**$ 961**	$ 1,064	**$ 3,195**	$ 2,565

[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 U.S. dollar debt issued from Canada have maturity dates in excess of five years.

[2] Sale of Australia assets for the three months ended September 30, 2007 and sale of Australia assets and interests in Chad for the nine months ended September 30, 2007.

[3] Operating Earnings from Continuing Operations is a non-GAAP measure that shows Net Earnings from Continuing Operations 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.

[4] Unrealized gains or losses have no impact on Cash Flow.

RESULTS OF OPERATIONS

UPSTREAM OPERATIONS

Production Volumes

	Nine Months Ended September 30		2007			2006				2005
	2007	2006	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Produced Gas *(MMcf/d)*	**3,513**	3,354	**3,630**	3,506	3,400	3,406	3,359	3,361	3,343	3,326
Crude Oil *(bbls/d)*	**108,875**	133,910	**109,967**	108,916	107,715	130,563	132,814	127,459	141,552	138,241
NGLs *(bbls/d)*	**24,610**	24,242	**26,416**	24,500	22,875	24,106	23,907	24,400	24,421	25,111
Continuing Operations *(MMcfe/d)* [1]	**4,314**	4,303	**4,448**	4,306	4,184	4,334	4,299	4,272	4,339	4,306
Discontinued Operations										
Ecuador *(bbls/d)* [2]	**-**	16,038	**-**	-	-	-	-	-	48,650	70,480
Discontinued Operations *(MMcfe/d)* [1]	**-**	96	**-**	-	-	-	-	-	292	423
Total *(MMcfe/d)* [1]	**4,314**	4,399	**4,448**	4,306	4,184	4,334	4,299	4,272	4,631	4,729

[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 3 percent or 149 MMcfe/d in the third quarter of 2007 compared to 2006 and was relatively unchanged in the nine months of 2007 compared to 2006 due to:

- Increased production from EnCana's natural gas key resource plays of 15 percent in the third quarter of 2007 and 12 percent in the nine months of 2007 compared to 2006; offset by
- Decreased production from EnCana's crude oil key resource plays of 20 percent in the third quarter of 2007 and 25 percent in the nine 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 September 30					Nine Months Ended September 30				
	Daily Production			Drilling Activity (net wells drilled)		Daily Production			Drilling Activity (net wells drilled)	
	2007 vs					2007 vs				
	2007	**2006**	2006	**2007**	2006	**2007**	**2006**	2006	**2007**	2006
Natural Gas *(MMcf/d)*										
Jonah	**588**	**29%**	455	**31**	48	**539**	**18%**	455	**112**	122
Piceance	**354**	**7%**	331	**72**	48	**346**	**7%**	324	**209**	170
East Texas	**144**	**36%**	106	**9**	12	**129**	**29%**	100	**27**	48
Fort Worth	**128**	**23%**	104	**17**	22	**119**	**17%**	102	**60**	78
Greater Sierra	**220**	**5%**	209	**27**	16	**208**	**-3%**	214	**82**	110
Cutbank Ridge	**245**	**47%**	167	**18**	35	**227**	**42%**	160	**70**	97
Bighorn	**128**	**32%**	97	**15**	7	**116**	**32%**	88	**52**	45
CBM [1]	**256**	**22%**	209	**323**	156	**251**	**33%**	189	**749**	572
Shallow Gas	**713**	**-3%**	734	**608**	475	**725**	**-2%**	740	**1,265**	921
	2,776	**15%**	2,412	**1,120**	819	**2,660**	**12%**	2,372	**2,626**	2,163
Oil *(Mbbls/d)*										
Foster Creek	**52**	**41%**	37	**16**	-	**48**	**33%**	36	**33**	6
Christina Lake	**5**	**-17%**	6	**2**	-	**5**	**-17%**	6	**7**	2
Partner's 50% Interest	**(28)**	**-**	-	**(9)**	-	**(26)**	**-**	-	**(20)**	-
	29	**-33%**	43	**9**	-	**27**	**-36%**	42	**20**	8
Pelican Lake	**24**	**4%**	23	**-**	-	**23**	**-8%**	25	**-**	-
	53	**-20%**	66	**9**	-	**50**	**-25%**	67	**20**	8
Total *(MMcfe/d)*	**3,090**	**10%**	2,809	**1,129**	819	**2,959**	**7%**	2,769	**2,646**	2,171

[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 September 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**		**$/Mcf**
Revenues, Net of Royalties / Price	**$ 1,113**	**$ 5.36**	**$ 598**	**$ 4.68**	**$ 1,711**	**$ 5.10**
Realized Financial Hedging	**214**		**336**		**550**	
Expenses						
Production and mineral taxes	**20**	**0.10**	**49**	**0.38**	**69**	**0.21**
Transportation and selling	**70**	**0.34**	**77**	**0.60**	**147**	**0.44**
Operating	**173**	**0.83**	**68**	**0.52**	**241**	**0.72**
Operating Cash Flow / Netback [1]	**$ 1,064**	**$ 4.09**	**$ 740**	**$ 3.18**	**$ 1,804**	**$ 3.73**
Netback including Realized Financial Hedging						**$ 5.38**
Gas Production Volumes *(MMcf/d)*		**2,243**		**1,387**		**3,630**

	2006					
	Canada		United States		Total	
		$/Mcf		$/Mcf		$/Mcf
Revenues, Net of Royalties / Price	$ 1,118	$ 5.59	$ 665	$ 6.04	$ 1,783	$ 5.75
Realized Financial Hedging	184		70		254	
Expenses						
Production and mineral taxes	18	0.09	47	0.43	65	0.21
Transportation and selling	74	0.37	64	0.57	138	0.44
Operating	157	0.78	64	0.59	221	0.71
Operating Cash Flow / Netback [1]	$ 1,053	$ 4.35	$ 560	$ 4.45	$ 1,613	$ 4.39
Netback including Realized Financial Hedging						$ 5.21
Gas Production Volumes *(MMcf/d)*		2,162		1,197		3,359

[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	$ 1,302	$ (23)	$ 48	**$ 1,327**
United States	735	71	128	**934**
Total Produced Gas	$ 2,037	$ 48	$ 176	**$ 2,261**

[1] Includes the impact of realized financial hedging.

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

- An 8 percent increase in natural gas production volumes offset by an 11 percent decrease in North American natural gas prices, excluding the impact of financial hedging; and
- Realized financial commodity hedging gains totaled $550 million in 2007 or $1.65 per Mcf compared to gains of $254 million or $0.82 per Mcf in 2006.

Produced gas volumes in the U.S. increased 16 percent in 2007 as a result of drilling and operational success and new facilities at Jonah, East Texas, Fort Worth and Piceance. Produced gas volumes in Canada increased 4 percent in 2007. Drilling success in the

key resource plays of Cutbank Ridge in northeast British Columbia, Coalbed Methane ("CBM") in central and southern Alberta and Bighorn in west central Alberta was offset by natural declines for conventional properties.

The decrease in EnCana's North American natural gas price in 2007, excluding the impact of financial hedges, is consistent with the decline in AECO and NYMEX benchmark prices and widening of the Rockies/NYMEX Basis Differential.

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 the higher U.S./Canadian dollar exchange rate. Natural gas per unit production and mineral taxes in the U.S. decreased $0.05 per Mcf or 12 percent in 2007 compared to 2006 mainly as a result of lower natural gas prices in the U.S. Rockies.

Natural gas per unit transportation and selling costs for Canada decreased 8 percent or $0.03 per Mcf in 2007 compared to 2006 mainly due to increased volumes offset slightly by the higher U.S./Canadian dollar exchange rate. Natural gas per unit transportation and selling costs for the U.S. increased 5 percent or $0.03 per Mcf in 2007 compared to 2006 primarily as a result of higher transportation rates.

Natural gas per unit operating expenses for Canada in 2007 were 6 percent or $0.05 per Mcf higher than in 2006 as a result of the higher U.S./Canadian dollar exchange rate and increased repairs and maintenance offset partially by lower electricity costs. Natural gas per unit operating expenses for the U.S. decreased 12 percent or $0.07 per Mcf in 2007 compared to 2006 primarily as a result of production growth rates at properties that exceeded the rate of increase in overall operating costs at those properties.

Nine Months Ended September 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**		**$/Mcf**
Revenues, Net of Royalties / Price	**$ 3,724**	**$ 6.15**	**$ 1,964**	**$ 5.51**	**$ 5,688**	**$ 5.91**
Realized Financial Hedging	**437**		**790**		**1,227**	
Expenses						
Production and mineral taxes	**62**	**0.10**	**127**	**0.36**	**189**	**0.20**
Transportation and selling	**213**	**0.35**	**220**	**0.62**	**433**	**0.45**
Operating	**530**	**0.88**	**228**	**0.63**	**758**	**0.79**
Operating Cash Flow / Netback [1]	**$ 3,356**	**$ 4.82**	**$ 2,179**	**$ 3.90**	**$ 5,535**	**$ 4.47**
Netback including Realized Financial Hedging						**$ 5.75**
Gas Production Volumes *(MMcf/d)*		**2,208**		**1,305**		**3,513**

	2006					
	Canada		United States		Total	
		$/Mcf		$/Mcf		$/Mcf
Revenues, Net of Royalties / Price	$ 3,772	$ 6.31	$ 2,117	$ 6.60	$ 5,889	$ 6.41
Realized Financial Hedging	267		31		298	
Expenses						
Production and mineral taxes	69	0.12	159	0.49	228	0.25
Transportation and selling	212	0.36	182	0.52	394	0.41
Operating	463	0.78	207	0.64	670	0.73
Operating Cash Flow / Netback [1]	$ 3,295	$ 5.05	$ 1,600	$ 4.95	$ 4,895	$ 5.02
Netback including Realized Financial Hedging						$ 5.35
Gas Production Volumes *(MMcf/d)*		2,178		1,176		3,354

[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	$ 4,039	$ 65	$ 57	**$ 4,161**
United States	2,148	334	272	**2,754**
Total Produced Gas	$ 6,187	$ 399	$ 329	**$ 6,915**

[1] Includes the impact of realized financial hedging.

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

- Realized financial commodity hedging gains totaled $1,227 million or $1.28 per Mcf in 2007 compared to gains of $298 million or $0.33 per Mcf in 2006; and
- A 5 percent increase in natural gas production volumes offset by an 8 percent decrease in North American natural gas prices, excluding the impact of financial hedging.

Produced gas volumes in the U.S. increased 11 percent in 2007 as a result of drilling and operational success and new facilities at Jonah, East Texas, Piceance and Fort Worth. Produced gas volumes in Canada increased 1 percent in 2007. Drilling success in the key resource plays of Cutbank Ridge, CBM and Bighorn was offset by natural declines for conventional properties.

The decrease in EnCana's North American natural gas price in 2007, excluding the impact of financial hedges, is consistent with the decline in AECO and NYMEX benchmark prices and widening of the Rockies/NYMEX Basis Differential.

Natural gas per unit production and mineral taxes for Canada decreased in 2007 compared to 2006 mainly due to lower natural gas prices offset slightly by the higher U.S./Canadian dollar exchange rate. Natural gas per unit production and mineral taxes in the U.S. decreased $0.13 per Mcf or 27 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 19 percent or $0.10 per Mcf in 2007 compared to 2006 primarily as a result of higher transportation rates in the Piceance area.

Natural gas per unit operating expenses for Canada in 2007 were 13 percent or $0.10 per Mcf higher than in 2006 as a result of higher repairs and maintenance expenses, increased property taxes and lease rentals 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 $0.03 per Mcf increase in operating costs for North American natural gas.

Crude Oil and NGLs

Three Months Ended September 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	**$ 433**	**$ 86**	**$ 160**	**$ 679**	$ 443	$ 76	$ 239	$ 758
Expenses								
Production and mineral taxes	**7**	**3**	**-**	**10**	9	5	-	14
Transportation and selling	**11**	**-**	**62**	**73**	3	-	126	129
Operating	**65**	**-**	**35**	**100**	61	-	56	117
Operating Cash Flow	**$ 350**	**$ 83**	**$ 63**	**$ 496**	$ 370	$ 71	$ 57	$ 498

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]	Revenue Variances in: Volume	**2007 Revenues, Net of Royalties**
Canada	$ 443	$ 29	$ (39)	**$ 433**
United States	76	(3)	13	**86**
Foster Creek/Christina Lake	239	1	(80)	**160**
Total Crude Oil and NGLs	$ 758	$ 27	$ (106)	**$ 679**

[1] Includes the impact of realized financial hedging.

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

- A 13 percent decrease in North American liquids production volumes partially offset by a 6 percent increase in North American liquids prices, excluding financial hedges; and
- Realized financial commodity hedging losses totaled $55 million or $4.36 per bbl in 2007 compared to losses of $48 million or $3.45 per bbl in 2006.

Total crude oil production at Foster Creek and Christina Lake decreased 33 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 9 percent due to natural declines in conventional properties.

Nine Months Ended September 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	**$ 1,191**	**$ 210**	**$ 552**	**$ 1,953**	$ 1,213	$ 208	$ 693	$ 2,114
Expenses								
Production and mineral taxes	**24**	**15**	**-**	**39**	27	14	-	41
Transportation and selling	**31**	**-**	**258**	**289**	11	-	373	384
Operating	**188**	**-**	**123**	**311**	176	-	138	314
Operating Cash Flow	**$ 948**	**$ 195**	**$ 171**	**$ 1,314**	$ 999	$ 194	$ 182	$ 1,375

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]	Revenue Variances in: Volume	**2007 Revenues, Net of Royalties**
Canada	$ 1,213	$ 116	$ (138)	**$ 1,191**
United States	208	(11)	13	**210**
Foster Creek/Christina Lake	693	164	(305)	**552**
Total Crude Oil and NGLs	$ 2,114	$ 269	$ (430)	**$ 1,953**

[1] Includes the impact of realized financial hedging.

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

- A 16 percent decrease in North American liquids production volumes partially offset by a 3 percent increase in North American liquids prices, excluding financial hedges; and

- Realized financial commodity hedging losses totaled $42 million or $1.13 per bbl in 2007 compared to losses of $141 million or $3.33 per bbl in 2006.

Total crude oil production at Foster Creek and Christina Lake decreased 36 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 11 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 September 30, 2007 versus 2006

Per Unit Results – Crude Oil

	Canada[1]		**Foster Creek/ Christina Lake**	
($ per barrel)	**2007**	2006	**2007**	2006
Price [2]	**$ 54.68**	$ 51.37	**$ 42.86**	$ 37.19
Expenses				
Production and mineral taxes	**1.01**	1.14	**-**	-
Transportation and selling	**1.47**	1.27	**2.10**	2.64
Operating	**8.68**	8.73	**12.55**	14.06
Netback	**$ 43.52**	$ 40.23	**$ 28.21**	$ 20.49
Crude Oil Production Volumes *(bbls/d)*	**81,227**	89,741	**28,740**	43,073
Pro forma Production Volumes *(bbls/d)* [3]			**28,740**	21,537

(1) Excludes Foster Creek/Christina Lake.
(2) Excludes the impact of realized financial hedging.
(3) 2006 production volumes adjusted on a pro forma basis to reflect the 50 percent contribution of Foster Creek and Christina Lake to the joint venture with ConocoPhillips.

Canada crude oil prices in 2007, excluding the impact of financial hedges, increased 6 percent compared to 2006, which reflects the changes in benchmark WTI and WCS crude oil prices compared to 2006. Foster Creek/Christina Lake crude oil prices in 2007, excluding the impact of financial hedges, increased 15 percent compared to 2006 due to realized price increases and decreased diluent costs recorded in the third quarter of 2007. Total realized financial commodity hedging losses for Canada and Foster Creek/Christina Lake were approximately $55 million or $4.36 per bbl of liquids in 2007 compared to losses of approximately $48 million or $3.45 per bbl of liquids in 2006.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2007 decreased 20 percent or $0.54 per bbl compared to 2006 due to a decrease in volumes being delivered to the U.S. Gulf Coast in 2007 compared to 2006. In addition, transportation and selling costs for Canada and Foster Creek/Christina Lake were impacted by the higher U.S./Canadian dollar exchange rate.

Canada crude oil per unit operating costs in 2007 were relatively unchanged compared to 2006 mainly due to decreased electricity costs offset by the higher U.S./Canadian dollar exchange rate and increased workovers. Foster Creek/Christina Lake crude oil per unit operating costs decreased 11 percent or $1.51 per bbl in 2007 compared to 2006. This decrease is mainly due to production growth rates at Foster Creek that exceeded the rate of increase in overall operating costs.

Nine Months Ended September 30, 2007 versus 2006

Per Unit Results – Crude Oil

	Canada[1]		Foster Creek/ Christina Lake	
($ per barrel)	**2007**	2006	**2007**	2006
Price [2]	**$ 47.68**	$ 47.05	**$ 38.45**	$ 35.42
Expenses				
Production and mineral taxes	**1.07**	1.11	**-**	-
Transportation and selling	**1.35**	1.01	**2.92**	2.60
Operating	**8.52**	7.40	**14.59**	12.11
Netback	**$ 36.74**	$ 37.53	**$ 20.94**	$ 20.71
Crude Oil Production Volumes *(bbls/d)*	**82,187**	92,460	**26,688**	41,450
Pro forma Production Volumes *(bbls/d)* [3]			**26,688**	20,725

(1) Excludes Foster Creek/Christina Lake.
(2) Excludes the impact of realized financial hedging.
(3) 2006 production volumes adjusted on a pro forma basis to reflect the 50 percent contribution of Foster Creek and Christina Lake to the joint venture with ConocoPhillips.

Canada crude oil prices in 2007, excluding the impact of financial hedges, was relatively consistent compared to 2006, which reflects the changes in benchmark WTI and WCS crude oil prices compared to 2006. Foster Creek/Christina Lake crude oil prices in 2007, excluding the impact of financial hedges, increased 9 percent compared to 2006 due to decreased diluent costs and a shift in the mix of sales points. Total realized financial commodity hedging losses for Canada and Foster Creek/Christina Lake were approximately $42 million or $1.13 per bbl of liquids in 2007 compared to losses of approximately $141 million or $3.33 per bbl of liquids in 2006.

Canada crude oil per unit transportation and selling costs increased 34 percent or $0.34 per bbl in 2007 compared to 2006 due to increased clean oil trucking costs at Weyburn and lower production from other properties. Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2007 increased 12 percent or $0.32 per bbl compared to 2006 due to a higher percentage of volumes being delivered to the U.S. Gulf Coast in 2007 compared to 2006. In addition, transportation and selling costs for Canada and Foster Creek/Christina Lake were impacted by the higher U.S./Canadian dollar exchange rate.

Canada crude oil per unit operating costs in 2007 increased 15 percent or $1.12 per bbl compared to 2006 mainly due to increased workovers and the higher U.S./Canadian dollar exchange rate offset partially by decreased electricity costs. Foster Creek/Christina Lake crude oil per unit operating costs increased 20 percent or $2.48 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, chemicals 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 September 30, 2007 versus 2006

Per Unit Results – NGLs

	Canada		United States	
($ per barrel)	**2007**	2006	**2007**	2006
Price [1]	**$ 62.87**	$ 55.95	**$ 60.17**	$ 61.76
Expenses				
Production and mineral taxes	**-**	-	**1.95**	4.42
Transportation and selling	**1.80**	0.74	**0.01**	0.01
Netback	**$ 61.07**	$ 55.21	**$ 58.21**	$ 57.33
NGLs Production Volumes *(bbls/d)*	**11,141**	11,387	**15,275**	12,520

(1) Excludes the impact of realized financial hedging.

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

U.S. NGLs per unit production and mineral taxes decreased $2.47 per bbl in 2007 compared to 2006 mainly as a result of a minor decrease in costs recorded in 2007 related to ad valorem tax for Colorado properties.

Canada NGLs per unit transportation and selling costs increased $1.06 per bbl in 2007 compared to 2006 primarily due to a minor increase in recorded transportation costs and the higher U.S./Canadian dollar exchange rate.

Nine Months Ended September 30, 2007 versus 2006

Per Unit Results – NGLs

	Canada		United States	
($ per barrel)	**2007**	2006	**2007**	2006
Price [1]	**$ 53.99**	$ 53.29	**$ 54.96**	$ 58.07
Expenses				
Production and mineral taxes	**-**	-	**3.63**	4.05
Transportation and selling	**1.04**	0.69	**0.01**	0.01
Netback	**$ 52.95**	$ 52.60	**$ 51.32**	$ 54.01
NGLs Production Volumes *(bbls/d)*	**10,954**	11,665	**13,656**	12,577

[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 decreased $0.42 per bbl in 2007 compared to 2006 mainly as a result of a minor decrease in costs recorded in 2007 related to ad valorem tax for Colorado properties.

Canada NGLs per unit transportation and selling costs increased $0.35 per bbl in 2007 compared to 2006 primarily due to a minor increase in recorded transportation costs and the higher U.S./Canadian dollar exchange rate.

Upstream Depreciation, Depletion and Amortization

Upstream DD&A expenses increased $154 million or 21 percent in the third quarter of 2007 and $280 million or 13 percent in the nine months of 2007 from the same periods in 2006. Unit of production DD&A rates were higher in 2007 compared to 2006 primarily as a result of increased future development costs and the higher U.S./Canadian dollar exchange rate. In addition, DD&A in 2007 includes an impairment of $24 million related to exploration prospects in Oman.

DOWNSTREAM OPERATIONS

Financial Results ($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Revenues	**$ 2,049**	$ -	**$ 5,109**	$ -
Expenses				
Operating	**98**	-	**317**	-
Purchased product	**1,607**	-	**3,898**	-
Operating Cash Flow	**$ 344**	$ -	**$ 894**	$ -

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 third quarter of 2007 benefited from strong 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 102 percent of that capacity during the third quarter and 95 percent during the nine months of 2007. Including the addition of other processed inputs combined with crude oil, refined products averaged 484,000 bbls/d through the third quarter and 454,000 bbls/d through the nine months of 2007.

Purchased products, consisting mainly of crude oil, represented 94 percent of total expenses in the third quarter and 92 percent in the nine months of 2007. Operating costs for labour, utilities and supplies comprised the balance of expenses for the quarter and nine months of 2007.

MARKET OPTIMIZATION

Financial Results ($ millions)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2007	2006	**2007**	2006
Revenues	**$ 629**	$ 731	**$ 2,107**	$ 2,272
Expenses				
Transportation and selling	**-**	4	**10**	17
Operating	**11**	18	**28**	49
Purchased product	**608**	677	**2,042**	2,160
Operating Cash Flow	**10**	32	**27**	46
Depreciation, depletion and amortization	**4**	3	**11**	8
Segment Income (Loss)	**$ 6**	$ 29	**$ 16**	$ 38

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 September 30**		**Nine Months Ended September 30**	
	2007	2006	**2007**	2006
Revenues	**$ (107)**	$ 428	**$ (673)**	$ 1,921
Expenses				
Operating	**-**	1	**(8)**	1
Depreciation, depletion and amortization	**25**	18	**64**	56
Segment Income (Loss)	**$ (132)**	$ 409	**$ (729)**	$ 1,864
Administrative	**73**	54	**263**	187
Interest, net	**102**	83	**297**	254
Accretion of asset retirement obligation	**17**	13	**46**	37
Foreign exchange (gain) loss, net	**74**	-	**69**	(158)
(Gain) Loss on divestitures	**(29)**	(304)	**(87)**	(321)

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

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

Administrative expenses increased $19 million in the third quarter and $76 million for the nine months ended September 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, increased staff levels, higher salaries and other related expenses.

Net interest expense in the nine months of 2007 increased $43 million from the same period in 2006 primarily as a result of higher average outstanding debt. EnCana's total long-term debt, including current portion, increased $412 million to $7,246 million at September 30, 2007 compared with $6,834 at December 31, 2006. EnCana's 2007 year-to-date weighted average interest rate on outstanding debt was 5.6 percent compared to 5.7 percent for the same period in 2006.

The foreign exchange loss of $69 in the nine months ended September 30, 2007 is due to the effects of revaluation of the partnership contribution receivable, translation of EnCana's monetary assets and liabilities and foreign exchange related to mark-to-market accounting for derivative financial instruments; offset by the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada and settlement of foreign denominated debt.

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2007**	2006	**2007**	2006
Continuing Operations				
Natural Gas	**$ (74)**	$ 348	**$ (558)**	$ 1,820
Crude Oil	**(33)**	80	**(115)**	101
	(107)	428	**(673)**	1,921
Expenses	**-**	-	**(7)**	2
	(107)	428	**(666)**	1,919
Income Tax Expense (Recovery)	**(38)**	146	**(221)**	661
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ (69)**	$ 282	**$ (445)**	$ 1,258

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. Changes in the mark-to-market gain or loss reflected in corporate revenues are the result of volatility between periods in the forward curve commodity price market and changes in the balance of unsettled contracts.

Income Tax

The effective tax rate for the nine months ended September 30, 2007 is 25.1 percent compared to 25.6 percent 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 substantively 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 $314 million in the third quarter of 2007 compared to $201 million in 2006. Cash taxes for the nine months of 2007 were $974 million compared to $829 million in 2006. The increase of $145 million generally reflects U.S. taxes in 2007 increasing by $397 million due to downstream refinery operations offset by the cash tax benefit of the legislative change ($231 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 September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Canada	**$ 962**	$ 777	**$ 2,424**	$ 2,684
United States	**452**	576	**1,313**	1,746
Other	**3**	12	**40**	51
Integrated Oilsands	**147**	87	**372**	482
Market Optimization	**2**	2	**5**	40
Corporate	**9**	20	**76**	49
Total Capital Investment	**1,575**	1,474	**4,230**	5,052
Acquisitions	**75**	12	**99**	298
Divestitures	**(59)**	(377)	**(505)**	(634)
Discontinued Operations	**-**	-	**-**	(2,415)
Net Capital Investment	**$ 1,591**	$ 1,109	**$ 3,824**	$ 2,301

EnCana's Total Capital Investment for the nine months ended September 30, 2007 was funded by Cash Flow and debt.

Canada, United States and Other Capital Investment

Capital investment during the third quarter and nine months of 2007 was primarily focused on continued development of EnCana's North American key resource plays.

The $704 million decrease in Canada, United States and Other capital investment in the nine months of 2007 compared to 2006 was primarily due to:

- A decrease of $260 million in Canada as a result of lower drilling and completion costs resulting from increased efficiencies and lower facilities investment; and
- A decrease of $433 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 additional fit-for-purpose rigs.

Deep Panuke

In early October, EnCana received regulatory approval from the Canada-Nova Scotia Offshore Petroleum Board to develop the Deep Panuke natural gas project located about 175 kilometres offshore Nova Scotia. Expected to start production in 2010, the $700 million project (about $550 million net to EnCana) is expected to deliver between 200 MMcf/d and 300 MMcf/d to markets in Canada and the northeast United States.

Integrated Oilsands Capital Investment

Capital investment during the third quarter and nine 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. Divestitures included the sale of certain assets in the Mackenzie Delta and Beaufort Sea, interests in Chad, assets in Australia and The Bow office project assets in 2007. In 2006, divestitures included the sale of the Entrega Pipeline in Colorado and interests in the Chinook heavy oil discovery offshore Brazil.

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 September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Net Cash From (Used in)				
Operating activities	**$ 2,200**	$ 1,655	**$ 6,277**	$ 6,277
Investing activities	**(1,490)**	(1,232)	**(3,832)**	(2,595)
Financing activities	**(739)**	(542)	**(2,306)**	(3,653)
Foreign exchange loss on cash and cash equivalents held in foreign currency	**(11)**	-	**(26)**	-
Increase (decrease) in cash and cash equivalents	**$ (40)**	$ (119)	**$ 113**	$ 29

Operating Activities

Cash Flow from Continuing Operations was $2,218 million during the third quarter of 2007 compared to $1,883 million for the same period in 2006. On a year-to-date basis Cash Flow from Continuing Operations was $6,519 million compared to $5,301 million for the same period in 2006. This increase was primarily due to increased Operating Cash Flow driven by U.S. refinery operations, higher realized financial commodity hedging gains, liquids prices 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 From Operating Activities.

Investing Activities

Net cash used for investing activities in the nine months of 2007 increased $1,237 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 nine months of 2007 decreased $1,021 million compared to the same period in 2006.

Financing Activities

Net issuance of long-term debt in the nine months of 2007 was $15 million compared to net repayments of $585 million in 2006. EnCana's net debt adjusted for working capital was $7,483 million as at September 30, 2007 compared with $6,566 million as at December 31, 2006. In 2007 EnCana issued C$500 million in Medium Term Notes and $500 million senior unsecured notes to repay a portion of EnCana's existing bank and commercial paper indebtedness. EnCana maintains numerous capital resources including committed bank credit facilities and shelf prospectuses. As at September 30, 2007, EnCana had available unused committed bank credit facilities in the amount of $4.2 billion and unused capacity under shelf prospectuses, the availability of which is dependant on market conditions, for up to $5.5 billion.

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.

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. The shelf replaces EnCana's C$1.0 billion shelf which was fully drawn.

On August 13, 2007, EnCana completed a public offering in the United States of senior unsecured notes in the aggregate principal amount of US$500 million. The notes have a coupon rate of 6.625 percent and mature on August 15, 2037. 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 third quarter of 2007, EnCana purchased 3.5 million of its Common Shares for total consideration of $218 million compared with 17.4 million Common Shares for total consideration of $900 million in 2006. During the nine months of 2007, EnCana purchased 38.9 million of its Common Shares for total consideration of $2,025 million compared with 61.1 million Common Shares for total consideration of $2,973 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 nine months ended September 30, 2007 totaled $453 million compared with $226 million in 2006. These dividends were funded by Cash Flow.

Financial Metrics

	September 30 2007	December 31 2006
Net Debt to Capitalization	**27%**	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 Net Debt to Capitalization ratio is relatively unchanged from December 31, 2006 as a result of higher net debt and a corresponding percentage increase in total capitalization.

Free Cash Flow

EnCana's nine months 2007 Free Cash Flow increased $1,941 million compared with the same period in 2006, which resulted from a combination of increased total Cash Flow and reduced total capital investment.

	Three Months Ended September 30		**Nine Months Ended September 30**		Year Ended
	2007	2006	**2007**	2006	2006
Cash Flow [1]	**$ 2,218**	$ 1,894	**$ 6,519**	$ 5,400	$ 7,161
Total Capital Investment	**1,575**	1,474	**4,230**	5,052	6,269
Free Cash Flow [2]	**$ 643**	$ 420	**$ 2,289**	$ 348	$ 892

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

[2] Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of Total Capital Investment and is used to determine the funds available for other investing and/or financing activities.

Outstanding Share Data

(millions)	**Nine Months Ended September 30**
Common Shares outstanding, beginning of year	**777.9**
Issued under option plans	**7.6**
Shares purchased	**(36.0)**
Common Shares outstanding, end of period	**749.5**
Weighted average Common Shares outstanding – diluted	**767.5**

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

Employees and directors have been granted options to purchase Common Shares under various plans. At September 30, 2007, 4.1 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 September 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 $7,249 million at September 30, 2007 are $897 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 September 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 115 Bcf at a weighted average price of $4.35 per Mcf. At September 30, 2007, these transactions had an unrealized loss of $251 million.

Leases

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

The Bow

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third party developer. Cost of design changes to the building requested by EnCana and leasehold improvements will be the responsibility of the Company. The development of The Bow office project remains conditional upon receipt of certain approvals and conditions being met, failing which the transaction could be unwound and EnCana would be required to reimburse the third party developer for the majority of the costs incurred and to assume the outstanding commitments of the project.

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.

Alberta Royalty Review

The Government of Alberta is in the midst of a comprehensive review of the province's oil and natural gas royalty structure. Until detailed and specific information of any royalty changes is outlined publicly and thoroughly evaluated by the Company, EnCana is unable to comment on how potential changes may impact the Company's operations.

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 capital investment program to be funded from Cash Flow and debt.

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, 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: the potential impact of implementation of the Alberta Royalty Review Panel's recommendations on EnCana's financial condition and projected 2008 capital investments; the expected timing of, and closing of, the sale of the Company's interests in Brazil; projections with respect to growth of natural gas production from unconventional resource plays and in-situ 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 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 royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this 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 September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
REVENUES, NET OF ROYALTIES	*(Note 6)*				
Upstream		**$ 2,883**	$ 2,622	**$ 8,597**	$ 7,817
Integrated Oilsands		**2,191**	248	**5,614**	713
Market Optimization		**629**	731	**2,107**	2,272
Corporate - Unrealized gain (loss) on risk management		**(107)**	428	**(673)**	1,921
		5,596	4,029	**15,645**	12,723
EXPENSES	*(Note 6)*				
Production and mineral taxes		**79**	79	**228**	269
Transportation and selling		**220**	271	**732**	795
Operating		**530**	420	**1,646**	1,227
Purchased product		**2,192**	677	**5,879**	2,160
Depreciation, depletion and amortization		**988**	791	**2,730**	2,346
Administrative		**73**	54	**263**	187
Interest, net	*(Note 9)*	**102**	83	**297**	254
Accretion of asset retirement obligation	*(Note 15)*	**17**	13	**46**	37
Foreign exchange (gain) loss, net	*(Note 10)*	**74**	-	**69**	(158)
(Gain) loss on divestitures	*(Note 8)*	**(29)**	(304)	**(87)**	(321)
		4,246	2,084	**11,803**	6,796
NET EARNINGS BEFORE INCOME TAX		**1,350**	1,945	**3,842**	5,927
Income tax expense	*(Note 11)*	**416**	602	**965**	1,519
NET EARNINGS FROM CONTINUING OPERATIONS		**934**	1,343	**2,877**	4,408
NET EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 7)*	**-**	15	**-**	581
NET EARNINGS		**$ 934**	$ 1,358	**$ 2,877**	$ 4,989
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 18)*				
Basic		**$ 1.24**	$ 1.66	**$ 3.79**	$ 5.32
Diluted		**$ 1.24**	$ 1.63	**$ 3.75**	$ 5.21
NET EARNINGS PER COMMON SHARE	*(Note 18)*				
Basic		**$ 1.24**	$ 1.68	**$ 3.79**	$ 6.02
Diluted		**$ 1.24**	$ 1.65	**$ 3.75**	$ 5.90

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Nine Months Ended September 30, **2007**	2006
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 11,344**	$ 9,481
Net Earnings		**2,877**	4,989
Dividends on Common Shares		**(453)**	(226)
Charges for Normal Course Issuer Bid	*(Note 16)*	**(1,618)**	(2,450)
RETAINED EARNINGS, END OF PERIOD		**$ 12,150**	$ 11,794

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME *(unaudited)*

($ millions)	Three Months Ended September 30, **2007**	2006	Nine Months Ended September 30, **2007**	2006
NET EARNINGS	**$ 934**	$ 1,358	**$ 2,877**	$ 4,989
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Foreign Currency Translation Adjustment	**859**	(7)	**1,798**	531
COMPREHENSIVE INCOME	**$ 1,793**	$ 1,351	**$ 4,675**	$ 5,520

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

($ millions)	Nine Months Ended September 30, **2007**	2006
ACCUMULATED OTHER COMPREHENSIVE INCOME, BEGINNING OF YEAR	**$ 1,375**	$ 1,262
Foreign Currency Translation Adjustment	**1,798**	531
ACCUMULATED OTHER COMPREHENSIVE INCOME, END OF PERIOD	**$ 3,173**	$ 1,793

As at September 30, 2007, the accumulated other comprehensive income consists of foreign currency translation adjustments of $3,173 million (December 31, 2006 - $1,375 million; September 30, 2006 - $1,793 million).

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		**As at September 30, 2007**	As at December 31, 2006
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 515**	$ 402
Accounts receivable and accrued revenues		**2,146**	1,721
Current portion of partnership contribution receivable	*(Note 5, 12)*	**293**	-
Risk management	*(Note 19)*	**820**	1,403
Inventories	*(Note 13)*	**775**	176
		4,549	3,702
Property, Plant and Equipment, net	*(Note 6)*	**32,156**	28,213
Investments and Other Assets		**604**	533
Partnership Contribution Receivable	*(Note 5, 12)*	**3,223**	-
Risk Management	*(Note 19)*	**57**	133
Goodwill		**2,873**	2,525
	(Note 6)	**$ 43,462**	$ 35,106
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 3,717**	$ 2,494
Income tax payable		**687**	926
Current portion of partnership contribution payable	*(Note 5, 12)*	**284**	-
Risk management	*(Note 19)*	**98**	14
Current portion of long-term debt	*(Note 14)*	**1,000**	257
		5,786	3,691
Long-Term Debt	*(Note 14)*	**6,246**	6,577
Other Liabilities		**205**	79
Partnership Contribution Payable	*(Note 5, 12)*	**3,236**	-
Risk Management	*(Note 19)*	**12**	2
Asset Retirement Obligation	*(Note 15)*	**1,272**	1,051
Future Income Taxes		**6,865**	6,240
		23,622	17,640
Shareholders' Equity			
Share capital	*(Note 16)*	**4,457**	4,587
Paid in surplus		**60**	160
Retained earnings		**12,150**	11,344
Accumulated other comprehensive income		**3,173**	1,375
Total Shareholders' Equity		**19,840**	17,466
		$ 43,462	$ 35,106

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

($ millions)		Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 934**	$ 1,343	**$ 2,877**	$ 4,408
Depreciation, depletion and amortization		**988**	791	**2,730**	2,346
Future income taxes	*(Note 11)*	**102**	401	**(9)**	690
Cash tax on sale of assets	*(Note 8)*	**-**	49	**-**	49
Unrealized (gain) loss on risk management	*(Note 19)*	**107**	(428)	**666**	(1,919)
Unrealized foreign exchange (gain) loss		**83**	4	**142**	(79)
Accretion of asset retirement obligation	*(Note 15)*	**17**	13	**46**	37
(Gain) loss on divestitures	*(Note 8)*	**(29)**	(304)	**(87)**	(321)
Other		**16**	14	**154**	90
Cash flow from discontinued operations		**-**	11	**-**	99
Net change in other assets and liabilities		**1**	21	**5**	48
Net change in non-cash working capital from continuing operations		**(19)**	(247)	**(247)**	3,305
Net change in non-cash working capital from discontinued operations		**-**	(13)	**-**	(2,476)
Cash From Operating Activities		**2,200**	1,655	**6,277**	6,277
INVESTING ACTIVITIES					
Capital expenditures	*(Note 6)*	**(1,650)**	(1,486)	**(4,329)**	(5,350)
Proceeds on disposal of assets	*(Note 8)*	**59**	377	**505**	634
Cash tax on sale of assets	*(Note 8)*	**-**	(49)	**-**	(49)
Net change in investments and other		**32**	(56)	**26**	(38)
Net change in non-cash working capital from continuing operations		**69**	(18)	**(34)**	(169)
Discontinued operations		**-**	-	**-**	2,377
Cash (Used in) Investing Activities		**(1,490)**	(1,232)	**(3,832)**	(2,595)
FINANCING ACTIVITIES					
Net issuance (repayment) of revolving long-term debt		**(871)**	470	**(909)**	(512)
Issuance of long-term debt	*(Note 14)*	**492**	-	**924**	-
Repayment of long-term debt		**-**	(73)	**-**	(73)
Issuance of common shares	*(Note 16)*	**5**	39	**158**	140
Purchase of common shares	*(Note 16)*	**(218)**	(900)	**(2,025)**	(2,973)
Dividends on common shares		**(149)**	(80)	**(453)**	(226)
Other		**2**	2	**(1)**	(9)
Cash (Used in) Financing Activities		**(739)**	(542)	**(2,306)**	(3,653)
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**11**	-	**26**	-
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**(40)**	(119)	**113**	29
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**555**	253	**402**	105
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 515**	$ 134	**$ 515**	$ 134

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 September 30, 2007 period end accumulated foreign currency translation adjustment balance of $3,173 million has been reclassified to AOCI (December 31, 2006 - $1,375 million; September 30, 2006 - $1,793 million). In addition, the change in the accumulated foreign currency translation adjustment balance for the three months and nine months ended September 30, 2007 of $859 million and $1,798 million, respectively, is now included in OCI in the Statement of Comprehensive Income (three months and nine months ended September 30, 2006 - $(7) million and $531 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 the Foster Creek and Christina Lake oil sands 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 Atlantic Canada, the Middle East and France.
- **Integrated Oilsands** is focused on two lines of business: the exploration for, and development and production of heavy oil from oil sands 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 September 30)

	Upstream					
	Canada		United States		Other	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 1,760**	$ 1,745	**$ 1,020**	$ 811	**$ 103**	$ 66
Expenses						
Production and mineral taxes	**27**	27	**52**	52	**-**	-
Transportation and selling	**81**	77	**77**	64	**-**	-
Operating	**238**	218	**68**	64	**79**	57
Purchased product	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**558**	505	**299**	222	**30**	6
Segment Income (Loss)	**$ 856**	$ 918	**$ 524**	$ 409	**$ (6)**	$ 3

	Total Upstream		Integrated Oilsands		Market Optimization	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 2,883**	$ 2,622	**$ 2,191**	$ 248	**$ 629**	$ 731
Expenses						
Production and mineral taxes	**79**	79	**-**	-	**-**	-
Transportation and selling	**158**	141	**62**	126	**-**	4
Operating	**385**	339	**134**	62	**11**	18
Purchased product	**-**	-	**1,584**	-	**608**	677
Depreciation, depletion and amortization	**887**	733	**72**	37	**4**	3
Segment Income (Loss)	**$ 1,374**	$ 1,330	**$ 339**	$ 23	**$ 6**	$ 29

	Corporate		Consolidated	
	2007	2006	**2007**	2006
Revenues, Net of Royalties	**$ (107)**	$ 428	**$ 5,596**	$ 4,029
Expenses				
Production and mineral taxes	**-**	-	**79**	79
Transportation and selling	**-**	-	**220**	271
Operating	**-**	1	**530**	420
Purchased product	**-**	-	**2,192**	677
Depreciation, depletion and amortization	**25**	18	**988**	791
Segment Income (Loss)	**$ (132)**	$ 409	**1,587**	1,791
Administrative			**73**	54
Interest, net			**102**	83
Accretion of asset retirement obligation			**17**	13
Foreign exchange (gain) loss, net			**74**	-
(Gain) loss on divestitures			**(29)**	(304)
			237	(154)
Net Earnings Before Income Tax			**1,350**	1,945
Income tax expense			**416**	602
Net Earnings From Continuing Operations			**$ 934**	$ 1,343

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 September 30)

Geographic and Product Information (Continuing Operations)

	Produced Gas					
	Canada		United States		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 1,327**	$ 1,302	**$ 934**	$ 735	**$ 2,261**	$ 2,037
Expenses						
Production and mineral taxes	**20**	18	**49**	47	**69**	65
Transportation and selling	**70**	74	**77**	64	**147**	138
Operating	**173**	157	**68**	64	**241**	221
Operating Cash Flow	**$ 1,064**	$ 1,053	**$ 740**	$ 560	**$ 1,804**	$ 1,613

	Oil & NGLs					
	Canada		United States		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 433**	$ 443	**$ 86**	$ 76	**$ 519**	$ 519
Expenses						
Production and mineral taxes	**7**	9	**3**	5	**10**	14
Transportation and selling	**11**	3	**-**	-	**11**	3
Operating	**65**	61	**-**	-	**65**	61
Operating Cash Flow	**$ 350**	$ 370	**$ 83**	$ 71	**$ 433**	$ 441

	Integrated Oilsands					
	Oil		Downstream Refining		Other	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 160**	$ 239	**$ 2,049**	$ -	**$ (18)**	$ 9
Expenses						
Transportation and selling	**62**	126	**-**	-	**-**	-
Operating	**35**	56	**98**	-	**1**	6
Purchased product	**-**	-	**1,607**	-	**(23)**	-
Operating Cash Flow	**$ 63**	$ 57	**$ 344**	$ -	**$ 4**	$ 3

	Integrated Oilsands	
	Total	
	2007	2006
Revenues, Net of Royalties	**$ 2,191**	$ 248
Expenses		
Transportation and selling	**62**	126
Operating	**134**	62
Purchased product	**1,584**	-
Operating Cash Flow	**$ 411**	$ 60

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. SEGMENTED INFORMATION (continued)

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

	Upstream					
	Canada		United States		Other	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 5,352**	$ 5,252	**$ 2,964**	$ 2,356	**$ 281**	$ 209
Expenses						
Production and mineral taxes	**86**	96	**142**	173	**-**	-
Transportation and selling	**244**	223	**220**	182	**-**	-
Operating	**718**	639	**228**	207	**233**	174
Purchased product	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**1,572**	1,495	**834**	648	**42**	25
Segment Income (Loss)	**$ 2,732**	$ 2,799	**$ 1,540**	$ 1,146	**$ 6**	$ 10

	Total Upstream		Integrated Oilsands		Market Optimization	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 8,597**	$ 7,817	**$ 5,614**	$ 713	**$ 2,107**	$ 2,272
Expenses						
Production and mineral taxes	**228**	269	**-**	-	**-**	-
Transportation and selling	**464**	405	**258**	373	**10**	17
Operating	**1,179**	1,020	**447**	157	**28**	49
Purchased product	**-**	-	**3,837**	-	**2,042**	2,160
Depreciation, depletion and amortization	**2,448**	2,168	**207**	114	**11**	8
Segment Income (Loss)	**$ 4,278**	$ 3,955	**$ 865**	$ 69	**$ 16**	$ 38

	Corporate		Consolidated	
	2007	2006	**2007**	2006
Revenues, Net of Royalties	**$ (673)**	$ 1,921	**$ 15,645**	$ 12,723
Expenses				
Production and mineral taxes	**-**	-	**228**	269
Transportation and selling	**-**	-	**732**	795
Operating	**(8)**	1	**1,646**	1,227
Purchased product	**-**	-	**5,879**	2,160
Depreciation, depletion and amortization	**64**	56	**2,730**	2,346
Segment Income (Loss)	**$ (729)**	$ 1,864	**4,430**	5,926
Administrative			**263**	187
Interest, net			**297**	254
Accretion of asset retirement obligation			**46**	37
Foreign exchange (gain) loss, net			**69**	(158)
(Gain) loss on divestitures			**(87)**	(321)
			588	(1)
Net Earnings Before Income Tax			**3,842**	5,927
Income tax expense			**965**	1,519
Net Earnings From Continuing Operations			**$ 2,877**	$ 4,408

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. SEGMENTED INFORMATION (continued)

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

Geographic and Product Information (Continuing Operations)

	Produced Gas					
	Canada		United States		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 4,161**	$ 4,039	**$ 2,754**	$ 2,148	**$ 6,915**	$ 6,187
Expenses						
Production and mineral taxes	**62**	69	**127**	159	**189**	228
Transportation and selling	**213**	212	**220**	182	**433**	394
Operating	**530**	463	**228**	207	**758**	670
Operating Cash Flow	**$ 3,356**	$ 3,295	**$ 2,179**	$ 1,600	**$ 5,535**	$ 4,895

	Oil & NGLs					
	Canada		United States		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 1,191**	$ 1,213	**$ 210**	$ 208	**$ 1,401**	$ 1,421
Expenses						
Production and mineral taxes	**24**	27	**15**	14	**39**	41
Transportation and selling	**31**	11	**-**	-	**31**	11
Operating	**188**	176	**-**	-	**188**	176
Operating Cash Flow	**$ 948**	$ 999	**$ 195**	$ 194	**$ 1,143**	$ 1,193

	Integrated Oilsands					
	Oil		Downstream Refining		Other	
	2007	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ 552**	$ 693	**$ 5,109**	$ -	**$ (47)**	$ 20
Expenses						
Transportation and selling	**258**	373	**-**	-	**-**	-
Operating	**123**	138	**317**	-	**7**	19
Purchased product	**-**	-	**3,898**	-	**(61)**	-
Operating Cash Flow	**$ 171**	$ 182	**$ 894**	$ -	**$ 7**	$ 1

	Integrated Oilsands	
	Total	
	2007	2006
Revenues, Net of Royalties	**$ 5,614**	$ 713
Expenses		
Transportation and selling	**258**	373
Operating	**447**	157
Purchased product	**3,837**	-
Operating Cash Flow	**$ 1,072**	$ 183

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. SEGMENTED INFORMATION (continued)

Capital Expenditures (Continuing Operations)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Capital				
Canada	**$ 962**	$ 777	**$ 2,424**	$ 2,684
United States	**452**	576	**1,313**	1,746
Other	**3**	12	**40**	51
Integrated Oilsands	**147**	87	**372**	482
Market Optimization	**2**	2	**5**	40
Corporate	**9**	20	**76**	49
	1,575	1,474	**4,230**	5,052
Acquisition Capital				
Canada	**60**	1	**67**	9
United States	**15**	11	**18**	268
Integrated Oilsands	**-**	-	**14**	21
	75	12	**99**	298
Total	**$ 1,650**	$ 1,486	**$ 4,329**	$ 5,350

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment As at		Total Assets As at	
	September 30, 2007	December 31, 2006	**September 30, 2007**	December 31, 2006
Canada	**$ 17,943**	$ 17,702	**$ 19,120**	$ 19,060
United States	**8,960**	8,494	**9,387**	9,036
Other	**144**	263	**168**	300
Integrated Oilsands	**4,566**	1,322	**9,481**	1,379
Market Optimization	**174**	154	**597**	468
Corporate	**369**	278	**4,709**	4,863
Total	**$ 32,156**	$ 28,213	**$ 43,462**	$ 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 and Total Assets includes EnCana's accrual to date of $101 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.

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 September 30,							
	Ecuador		United Kingdom		Midstream		Total	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties	**$ -**	$ -	**$ -**	$ -	**$ -**	$ 14	**$ -**	$ 14
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**-**	-	**-**	-
Transportation and selling	**-**	-	**-**	-	**-**	-	**-**	-
Operating	**-**	-	**-**	-	**-**	-	**-**	-
Purchased product	**-**	-	**-**	-	**-**	-	**-**	-
Depreciation, depletion and amortization	**-**	-	**-**	-	**-**	-	**-**	-
Interest, net	**-**	-	**-**	-	**-**	-	**-**	-
Foreign exchange (gain) loss, net	**-**	-	**-**	-	**-**	(4)	**-**	(4)
(Gain) loss on discontinuance	**-**	-	**-**	-	**-**	2	**-**	2
	-	-	**-**	-	**-**	(2)	**-**	(2)
Net Earnings (Loss) Before Income Tax	**-**	-	**-**	-	**-**	16	**-**	16
Income tax expense	**-**	-	**-**	(7)	**-**	8	**-**	1
Net Earnings (Loss) From Discontinued Operations	**$ -**	$ -	**$ -**	$ 7	**$ -**	$ 8	**$ -**	$ 15

	For the nine months ended September 30,							
	Ecuador		United Kingdom		Midstream		Total	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006
Revenues, Net of Royalties *	**$ -**	$ 200	**$ -**	$ -	**$ -**	$ 477	**$ -**	$ 677
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	**-**	-	**-**	5	**-**	6
(Gain) loss on discontinuance	**-**	279	**-**	-	**-**	(766)	**-**	(487)
	-	420	**-**	-	**-**	(378)	**-**	42
Net Earnings (Loss) Before Income Tax	**-**	(220)	**-**	-	**-**	855	**-**	635
Income tax expense	**-**	59	**-**	(5)	**-**	-	**-**	54
Net Earnings (Loss) From Discontinued Operations	**$ -**	$ (279)	**$ -**	$ 5	**$ -**	$ 855	**$ -**	$ 581

* 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 of 2006, 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 $505 million (2006 - $634 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 $66 million (2006 - $23 million).

Other

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

In May 2007, the Company completed the sale of 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 $208 million which resulted in a gain on sale of $59 million.

In August 2006, the Company completed the sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $367 million which resulted in a gain on sale of $304 million. After recording income tax of $49 million, EnCana recorded an after-tax gain of $255 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 September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Interest Expense - Long-Term Debt	**$ 113**	$ 88	**$ 331**	$ 269
Interest Expense - Other *	**72**	9	**178**	19
Interest Income *	**(83)**	(14)	**(212)**	(34)
	$ 102	$ 83	**$ 297**	$ 254

* 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 September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**$ (278)**	$ 4	**$ (608)**	$ (155)
Translation of U.S. dollar partnership contribution receivable issued from Canada	**252**	-	**595**	-
Other Foreign Exchange (Gain) Loss	**100**	(4)	**82**	(3)
	$ 74	$ -	**$ 69**	$ (158)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Current				
Canada	**$ 142**	$ 105	**$ 485**	$ 694
United States	**172**	51	**484**	87
Other Countries	**-**	45	**5**	48
Total Current Tax	**314**	201	**974**	829
Future	**102**	401	**(9)**	690
	$ 416	$ 602	**$ 965**	$ 1,519

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Net Earnings Before Income Tax	**$ 1,350**	$ 1,945	**$ 3,842**	$ 5,927
Canadian Statutory Rate	**32.3%**	34.7%	**32.3%**	34.7%
Expected Income Tax	**436**	674	**1,241**	2,055
Effect on Taxes Resulting from:				
Non-deductible Canadian Crown payments	**-**	23	**-**	75
Canadian resource allowance	**-**	-	**-**	(18)
Statutory and other rate differences	**12**	(63)	**36**	(80)
Effect of tax rate changes	**-**	-	**(37)**	(457)
Effect of legislative changes	**-**	-	**(231)**	-
Non-taxable downstream partnership income	**(21)**	-	**(40)**	-
Non-taxable capital (gains) losses	**(32)**	3	**(44)**	(30)
Other	**21**	(35)	**40**	(26)
	$ 416	$ 602	**$ 965**	$ 1,519
Effective Tax Rate	**30.8%**	31.0%	**25.1%**	25.6%

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, net of payments to date.

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, net of payments to date.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. INVENTORIES

	As at September 30, 2007	As at December 31, 2006
Product		
Canada	**$ 1**	$ 42
United States	**1**	-
Integrated Oilsands	**633**	8
Market Optimization	**140**	126
	$ 775	$ 176

14. LONG-TERM DEBT

	As at September 30, 2007	As at December 31, 2006
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 897**	$ 1,456
Unsecured notes	**1,431**	793
	2,328	2,249
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**-**	104
Unsecured notes	**4,921**	4,421
	4,921	4,525
Increase in Value of Debt Acquired *	**66**	60
Debt Discounts and Financing Costs	**(69)**	-
Current Portion of Long-Term Debt	**(1,000)**	(257)
	$ 6,246	$ 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.

On August 13, 2007, EnCana completed a public offering in the United States of senior unsecured notes in the aggregate principal amount of US$500 million. The notes have a coupon rate of 6.625 percent and mature on August 15, 2037.

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 September 30, 2007	As at December 31, 2006
Asset Retirement Obligation, Beginning of Year	**$ 1,051**	$ 816
Liabilities Incurred	**61**	68
Liabilities Settled	**(48)**	(51)
Change in Estimated Future Cash Flows	**4**	172
Accretion Expense	**46**	50
Other	**158**	(4)
Asset Retirement Obligation, End of Period	**$ 1,272**	$ 1,051

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. SHARE CAPITAL

	September 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	**7.6**		**158**	8.6		179
Stock-based Compensation	**-**		**13**	-		11
Common Shares Purchased	**(36.0)**		**(301)**	(85.6)		(734)
Common Shares Outstanding, End of Period	**749.5**	**$**	**4,457**	777.9	$	4,587

Normal Course Issuer Bid

To September 30, 2007, the Company purchased 38.9 million Common Shares for total consideration of approximately $2,025 million. Of the amount paid, $325 million was charged to Share capital and $1,700 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.

The following tables summarize the information about options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSARs") attached to them at September 30, 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	**(7.6)**	**23.75**
Forfeited	**(0.1)**	**22.90**
Outstanding, End of Period	**4.1**	**22.12**
Exercisable, End of Period	**4.1**	**22.12**

	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	2.1	11.58	0.6	11.58
17.00 to 23.49	0.1	1.0	22.86	0.1	22.86
23.50 to 23.99	3.1	0.6	23.89	3.1	23.89
24.00 to 24.99	0.2	0.8	24.51	0.2	24.51
25.00 to 25.99	0.1	1.0	25.61	0.1	25.61
	4.1	0.8	22.12	4.1	22.12

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at September 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 September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Current Service Cost	**$ 3**	$ 3	**$ 11**	$ 10
Interest Cost	**5**	5	**14**	13
Expected Return on Plan Assets	**(5)**	(4)	**(14)**	(12)
Expected Actuarial Loss on Accrued Benefit Obligation	**1**	1	**3**	4
Expected Amortization of Past Service Costs	**-**	-	**1**	1
Amortization of Transitional Obligation	**-**	-	**(1)**	(1)
Expense for Defined Contribution Plan	**9**	9	**25**	20
Net Benefit Plan Expense	**$ 13**	$ 14	**$ 39**	$ 35

For the period ended September 30, 2007, contributions of $8 million have been made to the defined benefit pension plans (2006 - $9 million).

B) Share Appreciation Rights ("SARs")

The following table summarizes the information about SARs at September 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 September 30, 2007, EnCana has not recorded any compensation costs related to the outstanding SARs (2006 - reduction of $1 million).

C) Tandem Share Appreciation Rights ("TSARs")

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

	Outstanding TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**17,276,191**	**44.99**
Granted	**4,592,238**	**56.19**
Exercised - SARs	**(1,704,867)**	**40.93**
Exercised - Options	**(12,020)**	**35.15**
Forfeited	**(1,060,528)**	**50.52**
Outstanding, End of Period	**19,091,014**	**50.28**
Exercisable, End of Period	**5,401,965**	**42.90**

For the period ended September 30, 2007, EnCana recorded compensation costs of $140 million related to the outstanding TSARs (2006 - $28 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. COMPENSATION PLANS (continued)

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 September 30, 2007:

	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	-	-
Granted	7,275,575	56.09
Forfeited	(327,350)	56.09
Outstanding, End of Period	6,948,225	56.09
Exercisable, End of Period	-	-

For the period ended September 30, 2007, EnCana recorded compensation costs of $9 million related to the outstanding Performance TSARs (2006 - nil).

E) Deferred Share Units ("DSUs")

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

	Outstanding DSUs	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	866,577	29.56
Granted, Directors	77,932	56.85
Exercised	(334,615)	29.56
Units, in Lieu of Dividends	7,616	61.20
Outstanding, End of Period	617,510	33.39
Exercisable, End of Period	617,510	33.39

For the period ended September 30, 2007, EnCana recorded compensation costs of $10 million related to the outstanding DSUs (2006 - $3 million).

F) Performance Share Units ("PSUs")

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

	Outstanding PSUs	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	4,766,329	27.48
Granted	18,060	60.90
Distributed	(2,937,491)	24.05
Forfeited	(160,557)	33.93
Outstanding, End of Period	1,686,341	33.19

For the period ended September 30, 2007, EnCana recorded compensation costs of $18 million related to the outstanding PSUs (2006 - $14 million).

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

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

18. PER SHARE AMOUNTS

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

	Three Months Ended				Nine Months Ended	
	March 31,	June 30,	September 30,		September 30,	
(millions)	2007	2007	**2007**	2006	**2007**	2006
Weighted Average Common Shares Outstanding - Basic	768.4	758.5	**750.4**	809.7	**759.1**	829.1
Effect of Dilutive Securities	11.2	6.7	**5.5**	14.6	**8.4**	16.5
Weighted Average Common Shares Outstanding - Diluted	779.6	765.2	**755.9**	824.3	**767.5**	845.6

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 September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Revenues, Net of Royalties	**$ 496**	$ 199	**$ 1,193**	$ 153
Operating Expenses and Other	**3**	1	**4**	4
Gain (Loss) on Risk Management - Continuing Operations	**499**	200	**1,197**	157
Gain (Loss) on Risk Management - Discontinued Operations	**-**	-	**-**	4
	$ 499	$ 200	**$ 1,197**	$ 161

	Unrealized Gain (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
Revenues, Net of Royalties	**$ (107)**	$ 428	**$ (673)**	$ 1,921
Operating Expenses and Other	**-**	-	**7**	(2)
Gain (Loss) on Risk Management - Continuing Operations	**(107)**	428	**(666)**	1,919
Gain (Loss) on Risk Management - Discontinued Operations	**-**	5	**-**	27
	$ (107)	$ 433	**$ (666)**	$ 1,946

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 September 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	**520**	**520**
Fair Value of Contracts in Place at Transition that Expired During 2007	**-**	**11**
Foreign exchange gains on Canadian dollar Contracts	**2**	**-**
Fair Value of Contracts Realized During 2007	**(1,197)**	**(1,197)**
Fair Value of Contracts Outstanding	**$ 741**	**$ (666)**
Paid Premiums on Unexpired Options	**26**	
Fair Value of Contracts and Premiums Paid, End of Period	**$ 767**	

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 (continued)

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

		As at September 30, 2007
Risk Management		
Current asset	$	820
Long-term asset		57
Current liability		98
Long-term liability		12
Net Risk Management Asset	$	767

A summary of all unrealized estimated fair value financial positions is as follows:

		As at September 30, 2007
Commodity Price Risk		
Natural gas	$	846
Crude oil		(103)
Power		22
Credit Derivatives		(1)
Interest Rate Risk		3
Total Fair Value Positions	$	767

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.

Natural Gas

At September 30, 2007, the Company's gas risk management activities from financial contracts had an unrealized gain of $841 million and a fair market value position of $846 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	1,608	2007	8.80	US$/Mcf	$ 262
NYMEX Fixed Price	765	2008	8.49	US$/Mcf	177
Options					
Purchased NYMEX Put Options	240	2007	6.00	US$/Mcf	(4)
Basis Contracts					
Canada	727	2007	(0.71)	US$/Mcf	21
United States	879	2007	(0.71)	US$/Mcf	256
Canada	191	2008	(0.78)	US$/Mcf	15
United States	849	2008	(1.03)	US$/Mcf	100
United States	20	2009	(0.71)	US$/Mcf	5
Canada	41	2010-2011	(0.41)	US$/Mcf	6
					838
Other Financial Positions *					3
Total Unrealized Gain on Financial Contracts					841
Paid Premiums on Unexpired Options					5
Total Fair Value Positions					$ 846

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

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

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Crude Oil
At September 30, 2007, the Company's oil risk management activities from financial contracts had an unrealized loss of $124 million and a fair market value position of $(103) 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	$ (50)
WTI NYMEX Fixed Price	23,000	2008	70.13	US$/bbl	(51)
Options					
Purchased WTI NYMEX Put Options	91,500	2007	55.34	US$/bbl	(20)
					(121)
Other Financial Positions *					(3)
Total Unrealized Loss on Financial Contracts					(124)
Paid Premiums on Unexpired Options					21
Total Fair Value Positions					$ (103)

* 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 September 30, 2007, these contracts had an unrealized gain of $22 million.

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.

The Bow Office Project

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third party developer. Cost of design changes to the building requested by EnCana and leasehold improvements will be the responsibility of the Company. The development of The Bow office project remains conditional upon receipt of certain approvals and conditions being met, failing which the transaction could be unwound and EnCana would be required to reimburse the third party developer for the majority of the costs incurred and to assume the outstanding commitments of the project.

Discontinued Merchant Energy Operations

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

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

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	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
TOTAL CONSOLIDATED										
Cash Flow [1]		**6,519**	**2,218**	2,549	1,752	7,161	1,761	1,894	1,815	1,691
Per share	- Basic	**8.59**	**2.96**	3.36	2.28	8.73	2.22	2.34	2.19	1.99
	- Diluted	**8.49**	**2.93**	3.33	2.25	8.56	2.18	2.30	2.15	1.96
Net Earnings		**2,877**	**934**	1,446	497	5,652	663	1,358	2,157	1,474
Per share	- Basic	**3.79**	**1.24**	1.91	0.65	6.89	0.84	1.68	2.60	1.74
	- Diluted	**3.75**	**1.24**	1.89	0.64	6.76	0.82	1.65	2.55	1.70
Operating Earnings [2]		**3,195**	**961**	1,376	858	3,271	675	1,078	824	694
Per share	- Diluted	**4.16**	**1.27**	1.80	1.10	3.91	0.84	1.31	0.98	0.80
CONTINUING OPERATIONS										
Cash Flow from Continuing Operations [3]		**6,519**	**2,218**	2,549	1,752	7,043	1,742	1,883	1,839	1,579
Net Earnings from Continuing Operations		**2,877**	**934**	1,446	497	5,051	643	1,343	1,593	1,472
Per share	- Basic	**3.79**	**1.24**	1.91	0.65	6.16	0.81	1.66	1.92	1.74
	- Diluted	**3.75**	**1.24**	1.89	0.64	6.04	0.80	1.63	1.88	1.70
Operating Earnings - Continuing Operations [4]		**3,195**	**961**	1,376	858	3,237	672	1,064	841	660
Effective Tax Rates using										
Net Earnings		**25.1%**				27.3%				
Operating Earnings, excluding divestitures		**27.5%**				33.7%				
Canadian Statutory Rate		**32.3%**				34.7%				
Foreign Exchange Rates *(US$ per C$1)*										
Average		**0.905**	**0.957**	0.911	0.854	0.882	0.878	0.892	0.892	0.866
Period end		**1.004**	**1.004**	0.940	0.867	0.858	0.858	0.897	0.897	0.857
CASH FLOW INFORMATION										
Cash from Operating Activities		**6,277**	**2,200**	2,168	1,909	7,973	1,697	1,655	2,325	2,297
Deduct (Add back):										
Net change in other assets and liabilities		**5**	**1**	(16)	20	138	90	21	38	(11)
Net change in non-cash working capital from continuing operations		**(247)**	**(19)**	(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]		**6,519**	**2,218**	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]		**6,519**	**2,218**	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 gain/loss on discontinuance, the after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada 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	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*									
Period end	**749.5**	**749.5**	752.8	761.3	777.9	777.9	800.1	815.8	836.2
Average - Basic	**759.1**	**750.4**	758.5	768.4	819.9	792.5	809.7	829.6	847.9
Average - Diluted	**767.5**	**755.9**	765.2	779.6	836.5	806.4	824.3	845.1	864.8
Price Range *($ per share)*									
TSX - C$									
High	**71.21**	**67.99**	71.21	59.65	62.52	61.90	62.52	59.38	57.10
Low	**51.55**	**59.33**	57.61	51.55	44.96	48.28	48.35	49.51	44.96
Close	**61.50**	**61.50**	65.52	58.40	53.66	53.66	52.01	58.78	54.50
NYSE - US$									
High	**66.87**	**65.18**	66.87	51.49	55.93	53.90	55.93	53.31	50.50
Low	**42.38**	**55.13**	50.58	42.38	39.54	42.75	43.32	44.02	39.54
Close	**61.85**	**61.85**	61.45	50.63	45.95	45.95	46.69	52.64	46.73
Dividends Paid *($ per share)*	**0.60**	**0.20**	0.20	0.20	0.375	0.10	0.10	0.10	0.075
Share Volume Traded *(millions)*	**960.1**	**301.4**	327.4	331.3	1,634.2	386.4	327.4	392.0	528.4
Share Value Traded *(US$ millions weekly average)*	**1,363.1**	**1,414.4**	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	**27%**				27%				
Net Debt to Adjusted EBITDA	**0.8x**				0.6x				
Return on Capital Employed	**15%**				25%				
Return on Common Equity	**18%**				34%				

Net Capital Investment *($ millions)*	**2007**	2006
Capital		
Canada	**$ 2,424**	$ 2,684
United States	**1,313**	1,746
Other	**40**	51
Integrated Oilsands	**372**	482
Market Optimization	**5**	40
Corporate [1]	**76**	49
Capital from Continuing Operations	**4,230**	5,052
Acquisitions		
Property		
Canada	**67**	9
United States	**18**	268
Integrated Oilsands	**14**	21
Divestitures		
Property		
Canada	**(55)**	(16)
United States	**(11)**	(7)
Other [2]	**(174)**	-
Corporate [3]	**(57)**	-
Corporate		
Market Optimization	**-**	(244)
Other [4]	**(208)**	(367)
Net Acquisition and Divestiture Activity from Continuing Operations	**(406)**	(336)
Discontinued Operations		
Ecuador	**-**	(1,116)
Midstream	**-**	(1,299)
Net Capital Investment	**$ 3,824**	$ 2,301

(1) Includes capital expenditures on the Bow Office Project for $51 million in 2007.
(2) Consists primarily of the sale of Mackenzie Delta assets which closed May 30, 2007 and sale of Australia assets which closed August 15, 2007.
(3) Sale of EnCana's office building project assets, The Bow, closed February 9, 2007.
(4) Sale of interests in Chad closed January 12, 2007 and the sale of shares of EnCanBrazil Limitada closed August 16, 2006.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties

Production Volumes	**2007**				2006				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS									
Produced Gas *(MMcf/d)*									
Canada	**2,208**	**2,243**	2,203	2,178	2,185	2,205	2,162	2,192	2,182
United States	**1,305**	**1,387**	1,303	1,222	1,182	1,201	1,197	1,169	1,161
Total Produced Gas	**3,513**	**3,630**	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	**40,767**	**40,345**	40,025	41,946	44,440	41,972	46,454	43,672	45,680
Heavy Oil - Foster Creek/Christina Lake	**26,688**	**28,740**	27,994	23,269	42,768	46,678	43,073	39,215	42,050
Heavy Oil - Other	**41,420**	**40,882**	40,897	42,500	45,858	41,913	43,287	44,572	53,822
Natural Gas Liquids [1]									
Canada	**10,954**	**11,141**	11,017	10,700	11,713	11,856	11,387	11,607	12,006
United States	**13,656**	**15,275**	13,483	12,175	12,494	12,250	12,520	12,793	12,415
Total Oil and Natural Gas Liquids	**133,485**	**136,383**	133,416	130,590	157,273	154,669	156,721	151,859	165,973
Total Continuing Operations *(MMcfe/d)*	**4,314**	**4,448**	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)*	**4,314**	**4,448**	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	452
Crude oil runs *(Mbbls/d)*	**430**	**460**	396	433
Crude utilization *(%)*	**95%**	**102%**	88%	96%
Refined products *(Mbbls/d)*	**454**	**484**	421	457

[2] Represents 100% of the Wood River and Borger refinery operations.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2007				2006				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS									
Produced Gas - Canada *($/Mcf)*									
Price	**6.15**	**5.36**	6.76	6.36	6.20	5.87	5.59	5.71	7.66
Production and mineral taxes	**0.10**	**0.10**	0.11	0.10	0.10	0.05	0.09	0.08	0.18
Transportation and selling	**0.35**	**0.34**	0.36	0.36	0.35	0.33	0.37	0.35	0.34
Operating	**0.88**	**0.83**	0.90	0.91	0.79	0.82	0.78	0.77	0.79
Netback	**4.82**	**4.09**	5.39	4.99	4.96	4.67	4.35	4.51	6.35
Produced Gas - United States *($/Mcf)*									
Price	**5.51**	**4.68**	5.73	6.24	6.35	5.65	6.04	6.08	7.70
Production and mineral taxes	**0.36**	**0.38**	0.17	0.53	0.49	0.50	0.43	0.22	0.85
Transportation and selling	**0.62**	**0.60**	0.65	0.61	0.54	0.60	0.57	0.50	0.49
Operating	**0.63**	**0.52**	0.71	0.67	0.65	0.68	0.59	0.70	0.64
Netback	**3.90**	**3.18**	4.20	4.43	4.67	3.87	4.45	4.66	5.72
Produced Gas - Total *($/Mcf)*									
Price	**5.91**	**5.10**	6.38	6.32	6.25	5.79	5.75	5.84	7.68
Production and mineral taxes	**0.20**	**0.21**	0.14	0.26	0.24	0.21	0.21	0.13	0.41
Transportation and selling	**0.45**	**0.44**	0.47	0.45	0.42	0.42	0.44	0.40	0.40
Operating	**0.79**	**0.72**	0.83	0.82	0.74	0.77	0.71	0.74	0.74
Netback	**4.47**	**3.73**	4.94	4.79	4.85	4.39	4.39	4.57	6.13
Natural Gas Liquids - Canada *($/bbl)*									
Price	**53.99**	**62.87**	55.21	43.26	51.12	44.79	55.95	55.19	48.84
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**1.04**	**1.80**	0.74	0.54	0.67	0.58	0.74	0.73	0.61
Netback	**52.95**	**61.07**	54.47	42.72	50.45	44.21	55.21	54.46	48.23
Natural Gas Liquids - United States *($/bbl)*									
Price	**54.96**	**60.17**	55.43	47.77	56.33	51.04	61.76	58.25	54.07
Production and mineral taxes	**3.63**	**1.95**	4.71	4.56	4.19	4.62	4.42	2.60	5.18
Transportation and selling	**0.01**	**0.01**	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Netback	**51.32**	**58.21**	50.71	43.20	52.13	46.41	57.33	55.64	48.88
Natural Gas Liquids - Total *($/bbl)*									
Price	**54.53**	**61.31**	55.33	45.66	53.81	47.97	58.99	56.80	51.50
Production and mineral taxes	**2.01**	**1.13**	2.59	2.43	2.16	2.35	2.31	1.36	2.63
Transportation and selling	**0.47**	**0.76**	0.34	0.26	0.33	0.29	0.36	0.35	0.31
Netback	**52.05**	**59.42**	52.40	42.97	51.32	45.33	56.32	55.09	48.56
Crude Oil - Light and Medium - *($/bbl)*									
Price	**53.68**	**61.18**	53.36	46.40	51.76	43.28	56.50	61.62	45.31
Production and mineral taxes	**2.07**	**1.89**	2.19	2.14	2.16	2.15	2.13	2.47	1.92
Transportation and selling	**1.44**	**1.53**	1.36	1.43	0.98	0.61	1.32	0.65	1.29
Operating	**9.27**	**9.51**	9.28	9.00	8.62	9.01	10.00	7.36	8.06
Netback	**40.90**	**48.25**	40.53	33.83	40.00	31.51	43.05	51.14	34.04
Crude Oil - Total - excluding Foster Creek/Christina Lake *($/bbl)*									
Price	**47.68**	**54.68**	47.02	41.42	44.83	37.65	51.37	55.58	35.39
Production and mineral taxes	**1.07**	**1.01**	1.16	1.06	1.11	1.11	1.14	1.28	0.92
Transportation and selling	**1.35**	**1.47**	1.31	1.27	0.91	0.60	1.27	0.76	1.00
Operating	**8.52**	**8.68**	8.85	8.06	7.69	8.59	8.73	6.84	6.67
Netback	**36.74**	**43.52**	35.70	31.03	35.12	27.35	40.23	46.70	26.80
Crude Oil - Heavy - Foster Creek/Christina Lake *($/bbl)*									
Price	**38.45**	**42.86**	39.40	33.28	36.49	39.32	37.19	46.53	23.08
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**2.92**	**2.10**	3.62	3.07	2.64	2.74	2.64	3.38	1.80
Operating (*)	**14.59**	**12.55**	14.02	17.12	12.38	13.07	14.06	11.78	10.39
Netback	**20.94**	**28.21**	21.76	13.09	21.47	23.51	20.49	31.37	10.89
Crude Oil - Total *($/bbl)*									
Price	**45.17**	**51.50**	44.92	39.19	41.83	36.94	48.74	51.62	30.76
Production and mineral taxes	**0.78**	**0.74**	0.84	0.77	0.77	0.74	0.81	0.88	0.66
Transportation and selling	**1.78**	**1.64**	1.94	1.75	1.40	1.11	1.74	1.54	1.24
Operating	**10.18**	**9.72**	10.27	10.54	9.09	10.05	10.20	8.34	7.82
Netback	**32.43**	**39.40**	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	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS (continued)									
Total Liquids - Canada *($/bbl)*									
Price	**45.92**	**52.50**	45.83	39.50	42.53	37.55	49.21	51.91	32.17
Production and mineral taxes	**0.71**	**0.66**	0.76	0.70	0.70	0.67	0.73	0.80	0.61
Transportation and selling	**1.72**	**1.66**	1.84	1.67	1.35	1.06	1.67	1.48	1.19
Operating	**9.22**	**8.78**	9.29	9.60	8.33	9.21	9.39	7.63	7.17
Netback	**34.27**	**41.40**	33.94	27.53	32.15	26.61	37.42	42.00	23.20
Total Liquids *($/bbl)*									
Price	**46.84**	**53.37**	46.81	40.25	43.71	38.69	50.37	52.44	33.87
Production and mineral taxes	**1.00**	**0.81**	1.16	1.04	0.99	0.99	1.05	0.96	0.96
Transportation and selling	**1.54**	**1.47**	1.65	1.51	1.24	0.98	1.52	1.35	1.10
Operating	**8.36**	**7.87**	8.41	8.81	7.66	8.47	8.58	7.01	6.64
Netback	**35.94**	**43.22**	35.59	28.89	33.82	28.25	39.22	43.12	25.17
Total *($/Mcfe)*									
Price	**6.27**	**5.80**	6.65	6.40	6.48	5.93	6.31	6.46	7.22
Production and mineral taxes	**0.19**	**0.19**	0.15	0.24	0.22	0.20	0.20	0.13	0.36
Transportation and selling	**0.42**	**0.41**	0.43	0.42	0.37	0.37	0.40	0.36	0.35
Operating [(1)]	**0.90**	**0.83**	0.93	0.95	0.86	0.90	0.87	0.84	0.82
Netback	**4.76**	**4.37**	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 $0.04/Mcfe (2006 - $0.01/Mcfe).

Impact of Realized Financial Hedging

Natural Gas *($/Mcf)*	**1.28**	**1.65**	1.24	0.92	0.47	0.91	0.82	0.66	(0.53)
Liquids *($/bbl)*	**(1.13)**	**(4.36)**	(1.34)	2.34	(3.32)	(3.30)	(3.45)	(3.43)	(3.12)
Total *($/Mcfe)*	**1.00**	**1.21**	0.96	0.82	0.25	0.60	0.53	0.40	(0.53)

FOR FURTHER INFORMATION:

EnCana Corporate Communications

Investor contact:

Paul Gagne
Vice-President, Investor Relations
(403) 645-4737

Susan Grey
Manager, Investor Relations
(403) 645-4751

Ryder McRitchie
Manager, Investor Relations
(403) 645-2007

Media contact:

Alan Boras
Manager, Media Relations
(403) 645-4747

EnCana Corporation
1800, 855 - 2nd Street SW
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: (403) 645-2000
Fax: (403) 645-3400
www.encana.com

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