2006 Quarterly Report

Q2 Second quarter report for the period ended June 30, 2006

Delivering On Our Potential

EnCana's second quarter cash flow reaches US$1.8 billion, or $2.15 per share – up 22 percent

Natural gas sales increase 5 percent to 3.36 billion cubic feet per day

Second quarter 2006 highlights

- Cash flow of US$2.15 per share diluted, or $1.82 billion
- Operating earnings of 98 cents per share diluted, or $824 million
- Net earnings of $2.55 per share diluted, or $2.16 billion, which includes:
  - A $582 million after-tax gain on the sale of discontinued operations comprised of
    - an $814 million gain on the sale of natural gas storage assets and
    - a $232 million net loss which is related to the recording of the expected final settlement of the sale of EnCana's Ecuador interests.
  - A $457 million gain due to Canadian federal and Alberta tax rate changes
  - An unrealized $160 million after-tax gain due to mark-to-market accounting of commodity price hedges
- Natural gas sales increased 5 percent to 3.36 billion cubic feet per day (Bcf/d)
- Oil and natural gas liquids (NGLs) sales from continuing operations down 2 percent to 153,470 barrels per day (bbls/d)
- Total natural gas and liquids sales of 4.28 billion cubic feet of gas equivalent per day (Bcfe/d), down 7 percent, due to divestiture of Ecuador interests
- Key resource play production up 12 percent
- Advanced market integration strategy with potential downstream partners for major expansion of in-situ oilsands developments over the next decade. Announcement expected in third quarter of 2006

Calgary, Alberta, (July 25, 2006) – EnCana Corporation (TSX & NYSE: ECA) generated robust cash flow and operating earnings during the second quarter of 2006 due to substantially increased heavy oil prices plus strong natural gas sales that benefited from favourable gas price hedges.

"After six months as CEO, I am pleased to report that our sales are on plan, capital investment, adjusted for the appreciation of the Canadian dollar, is within guidance and financial results are ahead of target. We continue to advance our oilsands market integration strategy with potential partners, which is aimed at helping pave the way for a major expansion of our bitumen production over the next decade. Our strategy remains constant – building the net asset value of every EnCana share through disciplined investment in unconventional resources," said Randy Eresman, EnCana's President & Chief Executive Officer. "In the past year, production from our key resource plays is up 12 percent and we are on track to achieve our 2006 guidance by growing sales by about 7 percent this year. So far in 2006, we have re-invested proceeds from our asset sales to purchase 43.7 million EnCana shares, representing 5.1 percent of the shares outstanding at the end of 2005."

Gas production to ramp up in second half of 2006

"As expected, our gas sales have been relatively flat for the first half of the year. However, production is projected to ramp up in the second half with the start up of two new gas processing plants in northeast British Columbia and west central Alberta, extensive shallow gas well tie-ins in southern Alberta and increased drilling in our Jonah field in Wyoming," Eresman said.

IMPORTANT NOTE: EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report sales and reserves on an after-royalties basis. EnCana's Ecuador interests and its natural gas liquids business were sold and are discontinued. The company is reporting its natural gas storage business as discontinued because EnCana is in the process of selling it. Total results, which include results from natural gas liquids business, Ecuador and natural gas storage, are reported in the company's financial statements included in this interim report and in supplementary documents posted on its website – www.encana.com. The company's financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP).

Second quarter 2006 highlights

(all year-over-year comparisons are to the second quarter of 2005)

Financial

- Cash flow per share diluted increased 22 percent to $2.15, or $1.82 billion
- Operating earnings per share increased 34 percent to 98 cents, or $824 million
- Net earnings of $2.16 billion, or $2.55 per share, compared to 94 cents per share one year earlier
- Return on capital employed of 29 percent
- Purchased 22.4 million EnCana shares at an average price of US$48.64 under the Normal Course Issuer Bid
- Reduced shares outstanding by 4.6 percent, net of share option exercises, since December 31, 2005
- Risk management measures resulted in a realized after-tax gain of $108 million

Operating

- Natural gas sales of 3.36 Bcf/d, up 5 percent
- Oil and NGLs sales from continuing operations down 2 percent to 153,470 bbls/d
- Total gas and liquids sales from continuing operations increased 3 percent to 4.28 Bcfe/d
- Total gas and liquids sales of 4.28 Bcfe/d, down 7 percent, due to divestiture of Ecuador interests
- Key resource play production up 12 percent
- Operating costs in continuing operations of 82 cents per thousand cubic feet equivalent (Mcfe), compared to 66 cents per Mcfe one year earlier
- Drilled 558 net wells in continuing operations, compared to 1,017 net wells one year earlier
- Upstream core capital investment in continuing operations of $1.6 billion

Strategic events

- EnCana approved two 30,000-barrel-per-day expansions at its Foster Creek in-situ oilsands project
    - First expansion expected to start up late 2008; the second expected by late 2009
    - Foster Creek oilsands production now expected to reach 120,000 bbls/d by the end of 2009
- Continued to advance market integration strategy with potential downstream partners for major expansion of in-situ oilsands developments over the next decade. Discussions remain on track towards an expected announcement in third quarter of 2006
- Completed first phase of sale of natural gas storage business for approximately $1.3 billion
- Invested about $250 million to increase interest in promising Deep Bossier natural gas assets in East Texas from 30 to 50 percent

2006 sales guidance affirmed, exchange rate impact updated in corporate guidance

EnCana affirms its 2006 sales guidance of between 4.35 billion and 4.52 billion cubic feet of gas equivalent per day, which, at the midpoint, is an increase of 7 percent from 2005 sales. The 2006 sales guidance is comprised of between 3.42 billion and 3.56 billion cubic feet of gas per day and between 155,000 and 160,000 bbls/d of oil and NGLs. In order to reflect exchange rates, EnCana has updated its 2006 US$/C$ exchange rate assumption from 85 to 88 cents. Updated guidance is posted on the company's website at encana.com.

Financial Summary – Total Consolidated

(for the period ended June 30) ($ millions, except per share amounts)	**Q2 2006**	Q2 2005	% Δ	**6 months 2006**	6 months 2005	% Δ
Cash flow	**1,815**	1,572	+ 15	**3,506**	2,985	+ 17
Per share diluted	**2.15**	1.76	+ 22	**4.10**	3.31	+ 24
Net earnings	**2,157**	839	n/a	**3,631**	794	n/a
Per share diluted	**2.55**	0.94	n/a	**4.24**	0.88	n/a
Operating earnings	**824**	655	+ 26	**1,518**	1,266	+ 20
Per share diluted	**0.98**	0.73	+ 34	**1.77**	1.41	+ 26
Earnings Reconciliation Summary – Total Consolidated						
Net earnings from continuing operations	**1,593**	774	n/a	**3,065**	612	n/a
Net earnings from discontinued operations	**564**	65	n/a	**566**	182	n/a
Net earnings	**2,157**	839	n/a	**3,631**	794	n/a
(Add back losses & deduct gains)						
Unrealized mark-to-market hedging gain (loss), after-tax	**160**	222	n/a	**990**	(419)	n/a
Unrealized foreign exchange gain (loss) on translation of U.S. dollar debt issued in Canada, after-tax	**134**	(38)	n/a	**131**	(53)	n/a
Future tax recovery due to Canada and Alberta tax rates reductions	**457**	-	n/a	**457**	-	n/a
Gain on sale of discontinued operations[1]	**582**	-	n/a	**535**	-	n/a
Operating earnings	**824**	655	+ 26	**1,518**	1,266	+ 20
Per share diluted	**0.98**	0.73	+ 34	**1.77**	1.41	+ 26

[1] Includes $814 million gain on natural gas storage sale and $232 million loss ($279 million loss in first half) on sale of Ecuador interests in second quarter

Sales & Drilling Summary

Total Consolidated

(for the period ended June 30) (After royalties)	**Q2 2006**	Q2 2005	% Δ	**6 months 2006**	6 months 2005	% Δ
Natural Gas sales (MMcf/d)	**3,361**	3,212	+ 5	**3,352**	3,179	+ 5
Natural gas sales per 1,000 shares (Mcf)	**369**	335	+ 10	**723**	653	+ 11
Oil and NGLs sales (bbls/d) [2]	**153,470**	230,284	- 33	**183,042**	229,978	- 20
Oil and NGLs sales per 1,000 shares (Mcfe) [2]	**101**	144	- 30	**237**	283	- 16
Total sales (MMcfe/d) [2]	**4,282**	4,594	- 7	**4,450**	4,559	- 2
Total sales per 1,000 shares (Mcfe) [2]	**470**	479	- 2	**960**	936	+ 3
Net wells drilled	**558**	1,021	- 45	**1,846**	2,378	- 22
Continuing Operations						
North America Natural Gas sales (MMcf/d)	**3,361**	3,212	+ 5	**3,352**	3,179	+ 5
North America Oil and NGLs (bbls/d)	**153,470**	157,108	- 2	**158,105**	157,145	+ 1
Total sales (MMcfe/d)	**4,282**	4,155	+ 3	**4,300**	4,122	+ 4
Net wells drilled	**558**	1,017	- 45	**1,840**	2,370	- 22

[2] Sales down due primarily to sale of Ecuador interests, which had sales of about 73,000 bbls/d in the first half of 2005

Key resource play production up 12 percent in past year
Second quarter 2006 oil and gas production from key North American resource plays increased 12 percent compared to the second quarter of 2005. This was driven mainly by increases in gas production from coalbed methane projects in central and southern Alberta, Bighorn in west-central Alberta, Cutbank Ridge in northeast British Columbia, Jonah in Wyoming, Piceance in Colorado and the Barnett Shale play in the Fort Worth basin.

Growth from key North American resource plays

Resource Play (After royalties)	Daily Production								
	2006			2005					2004
	YTD	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas (MMcf/d)									
Jonah	**456**	**450**	461	435	454	440	416	431	389
Piceance	**320**	**324**	316	307	326	302	302	300	261
East Texas	**96**	**93**	99	90	98	94	85	82	50
Fort Worth	**101**	**108**	93	70	88	66	63	61	27
Greater Sierra	**216**	**224**	208	219	226	225	228	195	230
Cutbank Ridge	**157**	**173**	140	92	125	105	80	56	40
Bighorn	**84**	**95**	72	55	56	57	53	56	42
CBM	**105**	**106**	104	57	77	62	51	38	17
Shallow Gas	**603**	**590**	615	625	625	616	633	625	592
Oil (Mbbls/d)									
Foster Creek	**35**	**33**	36	29	35	27	24	30	29
Christina Lake	**6**	**6**	6	5	5	6	7	4	4
Pelican Lake	**25**	**22**	29	26	28	27	27	21	19
Total (MMcfe/d)	**2,534**	**2,528**	2,536	2,311	2,479	2,326	2,259	2,176	1,960
% change from Q2 2005		**12**							
% change from prior period		**(0.3)**	**2.3**	**17.9**	**6.6**	**3.0**	**3.8**	**7.0**	

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled								
	2006			2005					2004
	YTD	Q2	Q1	Full year	Q4	Q3	Q2	Q1	Full Year
Natural Gas									
Jonah	**74**	**48**	26	104	21	25	30	28	70
Piceance	**122**	**59**	63	266	55	69	65	77	250
East Texas	**36**	**17**	19	84	20	21	22	21	50
Fort Worth	**56**	**27**	29	59	20	18	12	9	36
Greater Sierra	**94**	**34**	60	164	25	33	47	59	187
Cutbank Ridge	**62**	**36**	26	135	34	40	38	23	50
Bighorn	**38**	**18**	20	51	20	10	10	11	20
CBM	**352**	**19**	333	1,084	327	216	219	322	760
Shallow Gas	**396**	**199**	197	1,267	288	341	365	273	1,552
Oil									
Foster Creek	**10**	**-**	10	39	13	14	2	10	11
Christina Lake	**2**	**-**	2	-	-	-	-	-	2
Pelican Lake	**-**	**-**	-	52	-	3	33	16	92
Total	**1,242**	**457**	785	3,305	823	790	843	849	3,080

Second quarter realized natural gas prices, including hedging, up 6 percent from one year earlier
EnCana's second quarter realized gas price, including the impact of financial hedging, averaged $6.50 per thousand cubic feet (Mcf), up 6 percent from the comparable price of $6.11 per Mcf in the second quarter of 2005. EnCana's natural gas prices, excluding financial hedging, averaged $5.84 per Mcf, down 7 percent in the second quarter of 2006 from an average of $6.25 per Mcf in the same 2005 period. Following the recent warm winter, North American gas storage levels remain well above long-term averages for this time of year, a market condition that is expected to put downward pressure on short-term gas prices. The second quarter benchmark NYMEX index gas price averaged $6.78 per Mcf, up 1 percent from $6.73 per Mcf in the second quarter of 2005. The second quarter Canadian benchmark gas price was down 15 percent to C$6.27 per Mcf while U.S. Rockies benchmark gas prices were 11 percent lower to $5.36 per Mcf, compared to last year.

About 97 percent of remaining 2006 forecast gas sales has floor price protection
EnCana has entered into financial contracts, put options and fixed price agreements, for 97 percent of the company's forecast gas sales during the last half of 2006 at an average NYMEX price of $7.29 per Mcf. This gas price hedging strategy helps assure cash flow for the company's capital programs.

Managing transportation risk to gas prices
Natural gas transportation constraints between producing regions in the U.S. Rockies and Western Canada and consuming regions increase the volatility in gas prices. To add further certainty of cash flow, EnCana has entered into basis hedges to reduce this volatility. For the remainder of 2006, EnCana has hedged 100 percent of its anticipated U.S. Rockies basis differential exposure at an average of 65 cents per Mcf. In Canada for 2006, EnCana has hedged 34 percent of its anticipated AECO basis differential exposure at an average of 69 cents per Mcf and has an additional 40 percent of anticipated production subject to transport and aggregator contracts.

Second quarter realized liquids prices, including hedging, up 82 percent; world oil prices remain strong
During the second quarter of 2006, increased market reach via new pipelines to the southern U.S. refining region and strong asphalt demand for the summer paving season resulted in substantially higher prices for Canadian heavy oil. Second quarter realized liquids prices, including financial hedging, increased 82 percent to average $49.01 per barrel, compared to the same period in 2005. Excluding financial hedging, realized liquids prices increased 65 percent averaging $52.44 per barrel. In the second quarter, the West Texas Intermediate (WTI)/Western Canada Select differential averaged $17.55 per barrel, down 15 percent from $20.72 per barrel in the same 2005 period. Continued unrest in major world oil producing regions has kept global oil prices strong. During the second quarter of 2006, the benchmark WTI crude oil price averaged $70.72 per barrel, up 33 percent from the second quarter 2005 of $53.22 per barrel.

Risk management strategy
Detailed risk management positions at June 30, 2006 are presented in Note 14 to the unaudited second quarter consolidated financial statements. In the second quarter of 2006, EnCana's financial price risk management measures resulted in a realized after-tax gain of approximately $108 million, comprised of a $135 million gain on gas hedges, a $31 million loss on liquids hedges and a $4 million gain on other hedges.

Corporate developments

Quarterly dividend of 10 cents per share approved
EnCana's board of directors has approved a quarterly dividend of 10 cents per share, which is payable on September 29, 2006 to common shareholders of record as of September 15, 2006.

Normal Course Issuer Bid purchases

To date in 2006, EnCana has purchased for cancellation approximately 43.7 million of its shares at an average price of US$47.37 per share under its current Normal Course Issuer Bid, which allows the company to purchase up to 10 percent of the company's public float at the time of the approval of the bid – October 2005. The company had 815.8 million shares outstanding at June 30, 2006.

Ecuador indemnity

On February 28, 2006 EnCana completed the sale of its interests in Ecuador operations for $1.4 billion and recorded a loss on sale of $47 million. During the second quarter, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator. This is an event requiring indemnification under the terms of EnCana's sale agreement with Andes Petroleum Company. The purchaser requested payment and EnCana has accrued the maximum amount, calculated in accordance with the terms of the agreement, of approximately $265 million, which results in a $232 million net loss being recorded against net earnings in the second quarter of 2006. At this point EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreement will be required to be made to the purchaser.

Financial strength

EnCana maintains a strong balance sheet. At June 30, 2006 the company's net debt-to-capitalization ratio was 26:74. EnCana's net debt-to-adjusted-EBITDA multiple, on a trailing 12-month basis, was 0.6 times. These ratios are below the company's targeted range for net debt-to-capitalization of between 30 and 40 percent and 1.0 to 2.0 times for net debt-to-adjusted-EBITDA.

In the second quarter of 2006, EnCana invested $1,632 million of core capital. Net divestitures were $803 million, resulting in net capital investment in total operations of $829 million. EnCana's 2006 capital program is expected to be funded by cash flow.

EnCana Corporation

With an enterprise value of approximately US$46 billion, EnCana is one of North America's leading natural gas producers, the largest holder of gas and oil resource lands onshore North America and is a technical and cost leader in the in-situ recovery of oilsands bitumen. EnCana delivers predictable, reliable, profitable growth from its portfolio of long-life resource plays situated in Canada and the United States. Contained in unconventional reservoirs, resource plays are large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have lower geological and commercial development risk, lower average decline rates and longer producing lives than conventional plays. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

NOTE 1: Non-GAAP measures

This interim report contains references to cash flow, total operating earnings and adjusted EBITDA.

- Total operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain or loss on the sale of discontinued operations, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.
- Adjusted EBITDA is a non-GAAP measure that is defined as earnings from Continuing Operations before gain on disposition, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Management believes that the inclusion of total operating earnings enhances the comparability of the company's underlying financial performance between periods. The majority of the unrealized gains/losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years. 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.

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 necessarily represent value equivalency at the well head.

Unbooked resource potential

EnCana defines unbooked resource potential as quantities of oil and natural gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play performance and areal extent. Consequently, EnCana's unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

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, cash flow and increase in net asset value); anticipated life of proved reserves; anticipated unbooked resource potential; anticipated conversion of unbooked resource potential to proved reserves; anticipated growth and success of resource plays and the expected characteristics of resource plays; anticipated bitumen production expansion including expansions of and production from Foster Creek and the timing thereof; expected proportion of total production and cash flows contributed by natural gas; anticipated success of EnCana’s market risk mitigation strategy and its impact on cash flow, upside potential and downside protection; anticipated purchases pursuant to the Normal Course Issuer Bid; potential demand for gas; anticipated production in 2006 and beyond; anticipated drilling; potential capital expenditures and investment; potential oil, natural gas and NGLs sales in 2006 and beyond; anticipated ability to meet production, operating cost and sales guidance targets; anticipated costs, including costs associated with developing unbooked resource potential and expected costs to develop the company’s drilling inventory; the potential for reduced industry activity in the future and the impact thereof on costs; anticipated prices for crude oil and natural gas; anticipated indemnity payments related to the Ecuador divestiture and the potential amount of such payments; the expected date for receipt of California regulatory approvals in respect of the sale of the company’s remaining gas storage assets and the expected gain on the sale of such assets; the expected timing of the sale of certain offshore Brazil assets; 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 on 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 company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the company operates; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.

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

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read with the unaudited interim Consolidated Financial Statements ("Interim Consolidated Financial Statements") for the period ended June 30, 2006, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2005. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this MD&A.

The Interim Consolidated Financial Statements and comparative information have been prepared in United States dollars, except where another currency has been indicated and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated July 24, 2006.

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

EnCana's Business

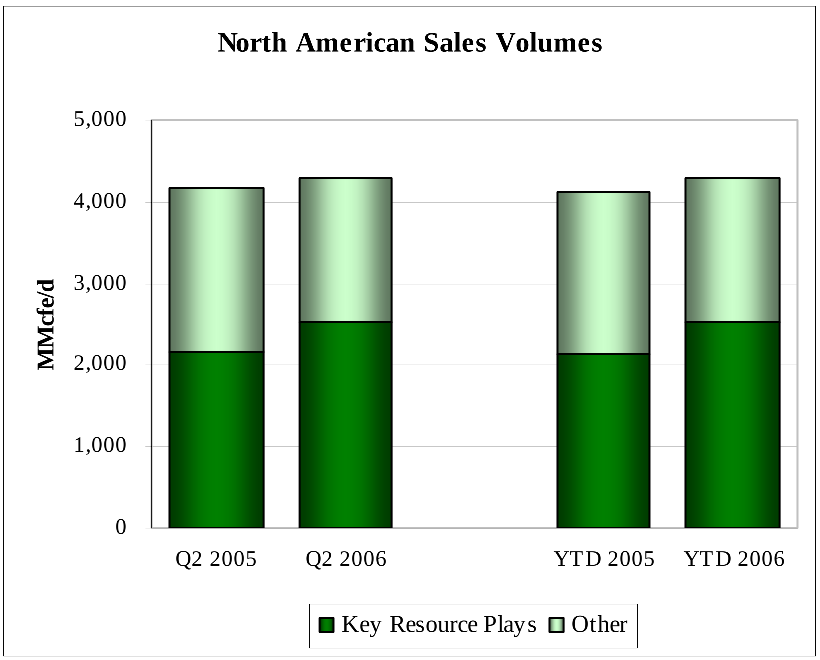
EnCana is a leading independent North American oil and gas company.

EnCana operates two continuing businesses:

- Upstream, which includes the Company's 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 United States. Frontier and International New Ventures exploration is mainly focused on opportunities in Chad, Brazil, the Middle East, Greenland and France; and

- Market Optimization, which is focused on enhancing the sale of EnCana's production. As part of these activities, Market Optimization buys and sells third party products to enhance EnCana's operating flexibility for transportation commitments, product type, delivery points and customer diversification.

2006 versus 2005 Results Review



EnCana pursues predictable, profitable growth from a portfolio of long-life resource plays in Canada and the United States.

In the second quarter of 2006, EnCana:

- Grew total North American sales volumes 3 percent to 4,282 million cubic feet ("MMcf") of gas equivalent per day ("MMcfe/d");
- Grew natural gas sales by 5 percent to 3,361 MMcf/d;
- Achieved second quarter sales of approximately 44,800 barrels per day (bbls/d) at EnCana's three steam-assisted gravity drainage ("SAGD") projects (Foster Creek, Christina Lake and Senlac). Production at Foster Creek in the second quarter of 2006 averaged over 33,100 bbls/d compared to approximately 24,400 bbls/d in the same period in 2005;
- Increased production from key resource plays by 12 percent over the second quarter of 2005;
- Completed the first stage of the sale of the gas storage business for approximately $1.3 billion;
- Acquired additional operated interest in East Texas which closed June 29, 2006;
- Increased cash flow by 15 percent to $1.8 billion;
- Increased net earnings by 157 percent to $2.2 billion; and
- Purchased 22.4 million common shares at an average price of $48.64 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of $1,095 million.

In the first half of 2006, EnCana:

- Grew total North American sales volumes 4 percent to 4,300 MMcfe/d;
- Grew natural gas sales by 5 percent to 3,352 MMcf/d;
- Achieved year-to-date sales of approximately 46,400 bbls/d at EnCana's three SAGD projects. Production at Foster Creek in the first half of 2006 averaged over 34,700 bbls/d compared to approximately 27,200 bbls/d in the same period in 2005;
- Added two new key resource plays – a natural gas play at Bighorn in west central Alberta and an in-situ oilsands project at Christina Lake in northeast Alberta;
- Increased production from key resource plays by 14 percent;
- Increased cash flow by 17 percent to $3.5 billion;
- Increased net earnings by 357 percent to $3.6 billion;
- Completed the sale of EnCana's Ecuador assets for $1.4 billion, the first stage of the sale of EnCana's natural gas storage operations for approximately $1.3 billion and the sale of the Entrega Pipeline for $244 million; and
- Approved two 30,000 bbls/d expansions at Foster Creek, the first to start up late 2008 and the second by late 2009.

EnCana enhances its ability to build shareholder value through financial discipline, strength and flexibility. In the first half of 2006, EnCana:

- Purchased 43.7 million common shares at an average price of $47.37 per share under the NCIB for a total cost of $2,073 million;
- Repaid revolving long-term debt by $982 million; and
- Reduced Net Debt to Capitalization to 26 percent from 33 percent and Net Debt to Adjusted EBITDA to 0.6x from 1.1x at December 31, 2005.

Business Environment

NATURAL GAS

Natural Gas Price Benchmarks (Average for the period)	Three Months Ended June 30 2006	2006 vs 2005	2005	Six Months Ended June 30 2006	2006 vs 2005	2005	Year Ended 2005
AECO Price *(C$/Mcf)*	**$ 6.27**	**-15%**	$ 7.37	**$ 7.77**	**11%**	$ 7.03	$ 8.48
NYMEX Price *($/MMBtu)*	**6.78**	**1%**	6.73	**7.88**	**21%**	6.50	8.62
Rockies (Opal) Price *($/MMBtu)*	**5.36**	**-11%**	6.00	**6.27**	**9%**	5.77	6.96
Basis Differential *($/MMBtu)*							
AECO/NYMEX	**1.23**	**58%**	0.78	**1.06**	**29%**	0.82	1.59
Rockies/NYMEX	**1.42**	**95%**	0.73	**1.61**	**121%**	0.73	1.66

The warmer than normal winter weather in the United States between the last week of December 2005 and the first week of February 2006 left gas storage levels at historical highs. This has partially offset concerns over the timing of the return of lost production from hurricanes Katrina and Rita and a forecast for another above normal hurricane season in 2006. Although the NYMEX gas price has trended downward since December 31, 2005, the second quarter of 2006 averaged $6.78/MMBtu, a slight increase over the same period in 2005.

A 15 percent lower average AECO gas price in the second quarter of 2006 compared with the same period in 2005 can be attributed to a wider AECO basis differential from NYMEX and a stronger Canadian dollar. A similar 11 percent lower average Rockies gas price in the second quarter of 2006 compared to the second quarter of 2005 can be attributed to a wider Rockies basis differential from NYMEX. Continued supply growth in the Rockies has put further strain on an already highly utilized pipeline grid. This combined with reduced demand during the shoulder season (April through June) has contributed to a wider basis differential in the Rockies. EnCana has mitigated its price risk with respect to its projected production from the region from the impact of further deterioration in the Rockies basis differential through the use of financial instrument hedging positions, the details of which are disclosed in Note 14 of the Interim Consolidated Financial Statements.

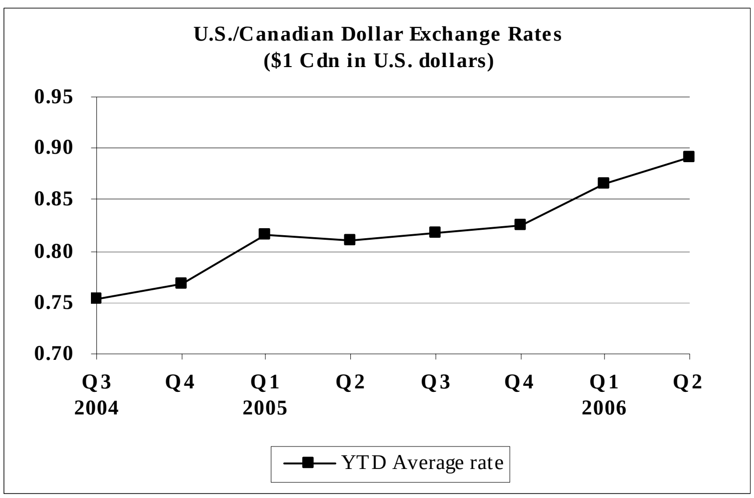
CRUDE OIL

Crude Oil Price Benchmarks	Three Months Ended June 30			Six Months Ended June 30			Year Ended
		2006 vs			2006 vs		
(Average for the period) ($/bbl)	**2006**	**2005**	2005	**2006**	**2005**	2005	2005
WTI	**$ 70.72**	**33%**	$ 53.22	**$ 67.13**	**30%**	$ 51.66	$ 56.70
WCS	**53.17**	**64%**	32.50	**43.98**	**38%**	31.89	36.39
Differential - WTI/WCS	**17.55**	**-15%**	20.72	**23.15**	**17%**	19.77	20.31

Concerns over geopolitical events and U.S. gasoline supplies combined to propel the West Texas Intermediate ("WTI") price above the $70 per bbl level for most of the second quarter. Concerns over Iran's nuclear program, shut-in of Nigerian production due to militant attacks and the ongoing instability in Iraq underscored worries about crude supplies. Temporary outages in Canadian synthetic supply and specification changes in the U.S. gasoline pool put further upward pressure on North American crude oil prices.

Canadian heavy oil differentials in the second quarter were 15 percent narrower than the same period in 2005 due to significant strength in residual fuel oil and asphalt markets driving higher pricing on Canadian heavy crude oil. The Western Canadian Select ("WCS") average sales price for the second quarter of 2006 was 75 percent of WTI, compared to 61 percent of WTI in the second quarter of 2005 and only 55 percent of WTI in the first quarter of 2006. The strength of WCS in the second quarter was also supported by the initial flows of Canadian heavy crude oil delivered directly to the U.S. Gulf Coast by the Pegasus Pipeline and new deliveries of Canadian crude oil into the U.S. via the Spearhead Pipeline.

U.S./CANADIAN DOLLAR EXCHANGE RATES



The impacts of currency fluctuations on EnCana's results should be considered when analyzing the Interim Consolidated Financial Statements. The value of the Canadian dollar increased by 11 percent or $0.088 to an average of US$0.892 in the second quarter of 2006 from an average of US$0.804 in the same period in 2005.

As a result, EnCana has reported an additional $8.80 of costs for every hundred Canadian dollars spent on capital projects, operating expenses and administrative expenses in the second quarter of 2006 relative to the second quarter of 2005. However, revenues were relatively unaffected by fluctuations in the U.S./Canadian dollar exchange rate because the commodity prices received by EnCana are largely based in U.S. dollars or in Canadian dollars at prices which are closely tied to the value of the U.S. dollar.

	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006	Year Ended 2005
Average U.S./Canadian dollar exchange rate	**$ 0.892**	**$ 0.879**	$ 0.825
Average U.S./Canadian dollar exchange rate for prior year	**$ 0.804**	**$ 0.810**	$ 0.768
Increase in reported capital, operating and administrative expenditures caused solely by fluctuations in exchange rates, for every hundred Canadian dollars spent	**$ 8.80**	**$ 6.90**	$ 5.70

Acquisitions and Divestitures

In keeping with EnCana's North American resource play strategy, the Company completed the following significant divestitures in the first six months of 2006:

Three Months Ended March 31

- The sale of the Entrega Pipeline located in Colorado on February 23 for approximately $244 million subject to post-closing adjustments; and
- The sale of its interests in Ecuador on February 28 for approximately $1.4 billion subject to post-closing adjustments.

Three Months Ended June 30

- The sale of the first stage of EnCana's gas storage business on May 12 for approximately $1.3 billion subject to post-closing adjustments. The second stage will close following receipt of California regulatory approvals, which are expected later this year.

Proceeds from these divestitures were directed primarily to a combination of the purchase of shares under EnCana's NCIB and debt reduction.

EnCana's previously announced sale of its 50 percent interest in the Chinook heavy oil discovery in offshore Brazil for approximately $350 million is expected to close in the third quarter of 2006 following receipt of Brazil regulatory approvals.

Consolidated Financial Results

($ millions, except per share amounts)	Three Months Ended June 30 2006	2006 vs 2005	2005	Six Months Ended June 30 2006	2006 vs 2005	2005	Year Ended 2005
Total Consolidated							
Cash Flow [1]	**$ 1,815**	**15%**	$ 1,572	**$ 3,506**	**17%**	$ 2,985	$ 7,426
- per share – diluted	**2.15**	**22%**	1.76	**4.10**	**24%**	3.31	8.35
Net Earnings	**2,157**	**157%**	839	**3,631**	**357%**	794	3,426
- per share – basic	**2.60**	**171%**	0.96	**4.33**	**381%**	0.90	3.95
- per share – diluted	**2.55**	**171%**	0.94	**4.24**	**382%**	0.88	3.85
Operating Earnings [2]	**824**	**26%**	655	**1,518**	**20%**	1,266	3,241
- per share – diluted	**0.98**	**34%**	0.73	**1.77**	**26%**	1.41	3.64
Continuing Operations							
Cash Flow from Continuing Operations [1]	**1,839**	**22%**	1,502	**3,418**	**24%**	2,749	6,962
Net Earnings from Continuing Operations	**1,593**	**106%**	774	**3,065**	**401%**	612	2,829
- per share – basic	**1.92**	**116%**	0.89	**3.65**	**429%**	0.69	3.26
- per share – diluted	**1.88**	**116%**	0.87	**3.58**	**426%**	0.68	3.18
Operating Earnings from Continuing Operations [2]	**841**	**38%**	611	**1,501**	**38%**	1,086	3,048
Revenues, Net of Royalties	**3,804**	**12%**	3,386	**8,474**	**56%**	5,424	14,266

(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are described and discussed under “Cash Flow”.

(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under “Operating Earnings”.

Consolidated Financial Results (continued)

Quarterly Summary

($ millions, except per share amounts)	2006		2005				2004	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Cash Flow [(1)]	**$ 1,815**	$ 1,691	$ 2,510	$ 1,931	$ 1,572	$ 1,413	$ 1,491	$ 1,363
- per share – diluted	**2.15**	1.96	2.88	2.20	1.76	1.55	1.60	1.46
Net Earnings	**2,157**	1,474	2,366	266	839	(45)	2,580	393
- per share – basic	**2.60**	1.74	2.77	0.31	0.96	(0.05)	2.81	0.43
- per share – diluted	**2.55**	1.70	2.71	0.30	0.94	(0.05)	2.77	0.42
Operating Earnings [(2)]	**824**	694	1,271	704	655	611	573	559
- per share – diluted	**0.98**	0.80	1.46	0.80	0.73	0.67	0.62	0.60
Continuing Operations								
Cash Flow from Continuing Operations [(1)]	**1,839**	1,579	2,390	1,823	1,502	1,247	1,358	1,256
Net Earnings from Continuing Operations	**1,593**	1,472	1,869	348	774	(162)	1,055	463
- per share – basic	**1.92**	1.74	2.19	0.41	0.89	(0.18)	1.15	0.50
- per share – diluted	**1.88**	1.70	2.14	0.40	0.87	(0.18)	1.13	0.50
Operating Earnings from Continuing Operations [(2)]	**841**	660	1,229	733	611	475	513	555
Revenues, Net of Royalties	**3,804**	4,670	5,860	2,982	3,386	2,038	3,542	2,195

(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are described and discussed under "Cash Flow".

(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under "Operating Earnings".

CASH FLOW

Cash flow measures are considered non-GAAP but are commonly used in the oil and gas industry to assist management and investors in measuring the Company's ability to finance capital programs and meet financial obligations. The calculation of cash flow is disclosed in the Consolidated Statement of Cash Flows in the Interim Consolidated Financial Statements.

Three Months Ended June 30

EnCana's second quarter 2006 cash flow was $1,815 million, an increase of $243 million or 15 percent from the same period in 2005. This increase reflects higher crude oil prices and natural gas sales volumes in 2006 partially reduced by increased costs. The results of discontinued operations reduced EnCana's cash flow by $24 million in the second quarter of 2006 compared with a $70 million increase in the same period of 2005.

EnCana's second quarter 2006 cash flow from continuing operations was $1,839 million, an increase of $337 million or 22 percent from the same period in 2005.

The increase resulted from:

- Average North American liquids prices, excluding financial hedges, increased 65 percent to $52.44 per bbl in the second quarter of 2006 compared to $31.80 per bbl in the same period in 2005;
- North American natural gas sales volumes in the second quarter of 2006 increased 5 percent to 3,361 MMcf/d from 3,212 MMcf/d in the same period in 2005; and
- Realized financial commodity hedging gains were $106 million after-tax in the second quarter of 2006 compared with losses of $71 million after-tax in the same period in 2005.

The increase in cash flow was partially reduced by:

- Average North American natural gas prices, excluding financial hedges, decreased 7 percent to $5.84 per Mcf in the second quarter of 2006 compared to $6.25 per Mcf in the same period in 2005;
- North American liquids sales volumes decreased 2 percent to 153,470 bbls/d in the second quarter of 2006 compared to 157,108 bbls/d in the same period in 2005;
- Operating expenses increased 25 percent to $395 million in the second quarter of 2006 compared with $315 million in the same period in 2005; and
- The current tax provision increased $228 million to $297 million in the second quarter of 2006 compared with $69 million in the same period in 2005. In 2005, $591 million of additional cash tax was incurred in the second quarter resulting from the disposition of the Gulf of Mexico operations, which was included in cash flow from investing activities.

Six Months Ended June 30

EnCana's first six months 2006 cash flow was $3,506 million, an increase of $521 million or 17 percent from the same period in 2005. This increase reflects higher commodity prices and sales volumes in 2006 partially reduced by increased costs. EnCana's discontinued operations contributed $88 million to cash flow compared with $236 million in 2005.

EnCana's first six months 2006 cash flow from continuing operations was $3,418 million, an increase of $669 million or 24 percent from the same period in 2005.

The increase resulted from:

- Average North American natural gas prices, excluding financial hedges, increased 12 percent to $6.75 per Mcf in the first six months of 2006 compared to $6.03 per Mcf in the same period in 2005;
- Average North American liquids prices, excluding financial hedges, increased 39 percent to $42.93 per bbl in the first six months of 2006 compared to $30.79 per bbl in the same period in 2005;
- North American natural gas sales volumes in the first six months of 2006 increased 5 percent to 3,352 MMcf/d from 3,179 MMcf/d in the same period in 2005; and
- Realized financial commodity hedging losses were $30 million after-tax in the first six months of 2006 compared with losses of $80 million after-tax in the same period in 2005.

The increase in cash flow was partially reduced by:

- Operating expenses increased 31 percent to $807 million in the first six months of 2006 compared with $615 million in the same period in 2005; and
- The current tax provision increased $348 million to $628 million in the first six months of 2006 compared with $280 million in the same period in 2005. In 2005, $591 million of additional cash tax was incurred in the first half of the year resulting from the disposition of the Gulf of Mexico operations, which was included in cash flow from investing activities.

NET EARNINGS

EnCana's first six months 2006 net earnings were $3,631 million compared with $794 million in the same period in 2005. Net earnings for the period includes unrealized mark-to-market gains after-tax of $990 million (2005 – losses after-tax of $419 million) and the effect of the tax rate reduction of $457 million. Net earnings also increased by $384 million to $566 million from discontinued operations mainly due to the gain on sale of the gas storage assets in the first half of 2006 offset partially by the Ecuador indemnity claim both of which are further discussed under the discontinued operations section.

Three Months Ended June 30

EnCana's second quarter 2006 net earnings from continuing operations were $1,593 million, an increase of $819 million compared with 2005. In addition to the items affecting cash flow as detailed previously, significant items affecting net earnings were:

- Unrealized mark-to-market gains of $161 million after-tax in 2006 compared with gains of $201 million after-tax in 2005;
- An increase in DD&A of $121 million as a result of the higher value of the Canadian dollar, higher DD&A rates and increased sales volumes;
- Unrealized foreign exchange gains of $134 million, after-tax in 2006 compared with losses of $38 million, after-tax in 2005; and

- A decrease in future income taxes due to Canadian federal and provincial tax rate reductions of $457 million.

Six Months Ended June 30

EnCana's first six months 2006 net earnings from continuing operations were $3,065 million, an increase of $2,453 million compared with 2005. In addition to the items affecting cash flow as detailed previously, significant items affecting net earnings were:

- Unrealized mark-to-market gains of $976 million after-tax in 2006 compared with losses of $421 million after-tax in 2005;
- An increase in DD&A of $207 million as a result of the higher value of the Canadian dollar, higher DD&A rates and increased sales volumes;
- Unrealized foreign exchange gains of $131 million, after tax in 2006 compared with losses of $53 million, after-tax in 2005; and
- A decrease in future income taxes due to Canadian federal and provincial tax rate reductions of $457 million.

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 Total Operating Earnings

	Three Months Ended June 30			**Six Months Ended June 30**			Year Ended
		2006 vs			**2006 vs**		
($ millions)	**2006**	**2005**	2005	**2006**	**2005**	2005	2005
Net Earnings, as reported	**$ 2,157**	**157%**	$ 839	**$ 3,631**	**357%**	$ 794	$ 3,426
Add back (losses) & deduct gains:							
- Unrealized mark-to-market accounting gain (loss), after-tax	**160**	**-28%**	222	**990**	**336%**	(419)	(277)
- Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, after-tax [(1)]	**134**	**453%**	(38)	**131**	**347%**	(53)	92
- Gain on sale of discontinued operations, after-tax	**582**		-	**535**		-	370
- Future tax recovery due to tax rate reductions	**457**		-	**457**		-	-
Operating Earnings [(2) (3)]	**$ 824**	**26%**	$ 655	**$ 1,518**	**20%**	$1,266	$ 3,241

(1) The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of 5 years.

(2) Operating Earnings is a non-GAAP measure that shows net earnings excluding the after-tax gain or loss from the disposition of discontinued operations, 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 in Canada and the effect of the changes in statutory income tax rates.

(3) Unrealized gains or losses have no impact on cash flow.

Summary of Total Operating Earnings (continued)

($ per Common Share – Diluted)	Three Months Ended June 30 2006	2006 vs 2005	2005	Six Months Ended June 30 2006	2006 vs 2005	2005	Year Ended 2005
Net Earnings, as reported	**$ 2.55**	**171%**	$ 0.94	**$ 4.24**	**382%**	$ 0.88	$ 3.85
Add back (losses) & deduct gains:							
- Unrealized mark-to-market accounting gain (loss), after-tax	**0.19**	**-24%**	0.25	**1.16**	**346%**	(0.47)	(0.31)
- Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, after-tax (1)	**0.15**	**475%**	(0.04)	**0.15**	**350%**	(0.06)	0.10
- Gain on sale of discontinued operations, after-tax	**0.69**		-	**0.63**		-	0.42
- Future tax recovery due to tax rate reductions	**0.54**		-	**0.53**		-	-
Operating Earnings (2) (3)	**$ 0.98**	**34%**	$ 0.73	**$ 1.77**	**26%**	$ 1.41	$ 3.64

(1) The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of 5 years.

(2) Operating Earnings is a non-GAAP measure that shows net earnings excluding the after-tax gain or loss from the disposition of discontinued operations, 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 in Canada and the effect of the changes in statutory income tax rates.

(3) Unrealized gains or losses have no impact on cash flow.

Summary of Operating Earnings from Continuing Operations

($ millions)	Three Months Ended June 30 2006	2006 vs 2005	2005	Six Months Ended June 30 2006	2006 vs 2005	2005	Year Ended 2005
Net Earnings from Continuing Operations, as reported	**$ 1,593**	**106%**	$ 774	**$ 3,065**	**401%**	$ 612	$ 2,829
Add back (losses) & deduct gains:							
- Unrealized mark-to-market accounting gain (loss), after-tax	**161**	**-20%**	201	**976**	**332%**	(421)	(311)
- Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, after-tax (1)	**134**	**453%**	(38)	**131**	**347%**	(53)	92
- Future tax recovery due to tax rate reductions	**457**		-	**457**		-	-
Operating Earnings from Continuing Operations (2) (3)	**$ 841**	**38%**	$ 611	**$ 1,501**	**38%**	$ 1,086	$ 3,048

(1) The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of 5 years.

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

(3) Unrealized gains or losses have no impact on cash flow.

RESULTS OF OPERATIONS

Upstream Operations

Financial Results from Continuing Operations

Three Months Ended June 30

($ millions)	2006				2005			
	Produced Gas	**Crude Oil & NGLs**	**Other**	**Total**	Produced Gas	Crude Oil & NGLs	Other	Total
Revenues, Net of Royalties	**$ 1,991**	**$ 686**	**$ 72**	**$ 2,749**	$ 1,785	$ 384	$ 58	$ 2,227
Expenses								
Production and mineral taxes	**38**	**13**	**-**	**51**	83	14	-	97
Transportation and selling	**123**	**19**	**-**	**142**	112	14	-	126
Operating	**228**	**92**	**63**	**383**	170	78	48	296
Operating Cash Flow	**$ 1,602**	**$ 562**	**$ 9**	**2,173**	$ 1,420	$ 278	$ 10	1,708
Depreciation, depletion and amortization				**768**				648
Upstream Income				**$ 1,405**				$ 1,060

Financial Results from Continuing Operations

Six Months Ended June 30

($ millions)	2006				2005			
	Produced Gas	**Crude Oil & NGLs**	**Other**	**Total**	Produced Gas	Crude Oil & NGLs	Other	Total
Revenues, Net of Royalties	**$ 4,150**	**$ 1,136**	**$ 154**	**$ 5,440**	$ 3,482	$ 732	$ 119	$ 4,333
Expenses								
Production and mineral taxes	**163**	**27**	**-**	**190**	158	26	-	184
Transportation and selling	**256**	**35**	**-**	**291**	226	31	-	257
Operating	**449**	**181**	**146**	**776**	335	149	104	588
Operating Cash Flow	**$ 3,282**	**$ 893**	**$ 8**	**4,183**	$ 2,763	$ 526	$ 15	3,304
Depreciation, depletion and amortization				**1,512**				1,308
Upstream Income				**$ 2,671**				$ 1,996

Upstream Revenues

Three Months Ended June 30

Revenues, net of royalties, increased in the second quarter of 2006 compared with the same period in 2005 due to:

- A 65 percent increase in North American liquids prices offset slightly by a 2 percent decrease in liquids sales volumes; and
- Realized financial commodity hedging gains totaled $155 million in the second quarter of 2006 compared to losses of $112 million for the same period in 2005.

Six Months Ended June 30

Revenues, net of royalties, increased in the first six months of 2006 compared with the same period in 2005 as a result of:

- A 39 percent increase in North American liquids prices combined with a slight increase in liquids sales volumes;
- A 12 percent increase in North American gas prices combined with a 5 percent increase in natural gas sales volumes; and
- Realized financial commodity hedging losses totaled $49 million in the first six months of 2006 compared to losses of $134 million for the same period in 2005.

Revenue Variances for 2006 Compared to 2005 from Continuing Operations

Three Months Ended June 30
($ millions)

	2005 Revenues, Net of Royalties	Revenue Variances in: Price (1)	Volume	**2006 Revenues, Net of Royalties**
Produced Gas				
Canada	$ 1,184	$ 88	$ 24	**$ 1,296**
United States	601	30	64	**695**
Total Produced Gas	$ 1,785	$ 118	$ 88	**$ 1,991**
Crude Oil and NGLs				
Canada	$ 330	$ 301	$ (16)	**$ 615**
United States	54	17	-	**71**
Total Crude Oil and NGLs	$ 384	$ 318	$ (16)	**$ 686**

(1) Includes the impact of realized financial hedging.

Six Months Ended June 30
($ millions)

	2005 Revenues, Net of Royalties	Revenue Variances in: Price (1)	Volume	**2006 Revenues, Net of Royalties**
Produced Gas				
Canada	$ 2,317	$ 330	$ 90	**$ 2,737**
United States	1,165	125	123	**1,413**
Total Produced Gas	$ 3,482	$ 455	$ 213	**$ 4,150**
Crude Oil and NGLs				
Canada	$ 623	$ 366	$ 15	**$ 1,004**
United States	109	35	(12)	**132**
Total Crude Oil and NGLs	$ 732	$ 401	$ 3	**$ 1,136**

(1) Includes the impact of realized financial hedging.

Three Months Ended June 30

The increase in liquids sales prices and natural gas realized financial commodity hedging gains accounts for the majority of the approximately 86 percent of the increase in revenues, net of royalties, in the second quarter of 2006 compared with the same period in 2005. The balance of the increase in revenues results from an increase in natural gas sales volumes.

Produced gas volumes in Canada increased 2 percent in the second quarter of 2006 mainly due to 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. Natural declines and the impact of wet weather in southern Alberta resulted in lower production volumes from the mature Shallow Gas key resource play as well as conventional properties.

Produced gas volumes in the U.S. increased 10 percent in the second quarter of 2006 as a result of drilling success at Fort Worth, Jonah and Piceance as well as the impact of property acquisitions in the Fort Worth Basin in late 2005.

North American crude oil and NGLs volumes decreased 2 percent as a result of a property payout, the dispositions of non-core Canadian conventional producing assets in June 2005 and natural production declines. 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. Decreases were offset somewhat by production increases at the Foster Creek heavy oil project.

Six Months Ended June 30

The increase in sales prices accounts for approximately 80 percent of the increase in revenues, net of royalties, in the first half of 2006 compared with the same period in 2005. The balance of the increase in revenues results from an increase in sales volumes.

Produced gas volumes in Canada increased 3 percent in the first half of 2006 mainly due to drilling success in the key resource plays of Cutbank Ridge in northeast British Columbia, CBM in central and southern Alberta and Bighorn in west central Alberta. Natural declines and the impact of wet weather in southern Alberta resulted in lower production volumes from the mature Shallow Gas key resource play as well as conventional properties.

Produced gas volumes in the U.S. increased 9 percent in the first half of 2006 as a result of drilling success at Fort Worth, Jonah, Piceance and East Texas as well as the impact of property acquisitions in the Fort Worth Basin in late 2005.

North American crude oil and NGLs volumes increased slightly as a result of production increases at the Foster Creek and Pelican Lake heavy oil properties. These increases were offset somewhat by Pelican Lake reaching payout early in the second quarter of 2006, the dispositions of non-core Canadian conventional producing assets in June 2005 and natural production declines.

Upstream Sales Volumes

Quarterly Sales Volumes

	2006		2005				2004	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Produced Gas *(MMcf/d)*	**3,361**	3,343	3,326	3,222	3,212	3,146	3,087	3,096
Crude Oil *(bbls/d)*	**129,070**	138,370	134,178	124,402	132,294	130,826	132,061	142,506
NGLs *(bbls/d)*	**24,400**	24,421	25,111	26,055	24,814	26,358	27,409	27,167
Continuing Operations *(MMcfe/d)* (1)	**4,282**	4,320	4,282	4,125	4,155	4,089	4,044	4,114
Discontinued Operations								
Ecuador *(bbls/d)* (2)	-	50,150	69,943	68,710	73,176	72,487	77,876	74,846
United Kingdom *(BOE/d)* (3)	-	-	-	-	-	-	13,927	20,222
Discontinued Operations *(MMcfe/d)* (1)	-	301	419	412	439	435	551	570
Total *(MMcfe/d)* (1)	**4,282**	4,621	4,701	4,537	4,594	4,524	4,595	4,684

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

(2) As the Ecuador sale occurred on February 28, 2006 only two months of volumes are included in Q1 2006.

(3) Includes natural gas and liquids (converted to BOE).

Sales volumes from continuing operations in the second quarter of 2006 increased 3 percent or 127 MMcfe/d from the comparable period in 2005 for the following reasons:

- Production from EnCana's key resource plays increased 12 percent; 13 percent for natural gas and 5 percent for crude oil;
- Drilling success in the key resource gas plays of Cutbank Ridge, CBM, Bighorn, Fort Worth, Jonah and Piceance offset somewhat by natural declines at Shallow Gas and the impact of wet weather in southern Alberta; and
- Expansion of Foster Creek facilities partially offset by the Pelican Lake heavy oil project reaching payout in April 2006.

Sales volumes from continuing operations in the first half of 2006 increased 4 percent or 178 MMcfe/d from the comparable period in 2005 for the following reasons:

- Production from EnCana's key resource plays increased 14 percent; 14 percent for natural gas and 18 percent for crude oil;

- Drilling success in the key resource gas plays of Cutbank Ridge, CBM, Bighorn, Fort Worth, Jonah, Piceance and East Texas as well as the impact of property acquisitions in the Fort Worth Basin in late 2005; and
- Expansion of Foster Creek facilities in the fourth quarter of 2005.

Key Resource Plays

	Daily Production					
	2006			2005		
	YTD	**Q2**	Q1	YTD	Q2	Q1
Natural Gas *(MMcf/d)*						
Jonah	**456**	**450**	461	424	416	431
Piceance	**320**	**324**	316	300	302	300
East Texas	**96**	**93**	99	83	85	82
Fort Worth	**101**	**108**	93	62	63	61
Greater Sierra	**216**	**224**	208	213	228	195
Cutbank Ridge	**157**	**173**	140	68	80	56
Bighorn	**84**	**95**	72	54	53	56
CBM	**105**	**106**	104	45	51	38
Shallow Gas	**603**	**590**	615	629	633	625
Oil *(Mbbls/d)*						
Foster Creek	**35**	**33**	36	27	24	30
Christina Lake	**6**	**6**	6	5	7	4
Pelican Lake	**25**	**22**	29	24	27	21
Total *(MMcfe/d)*	**2,534**	**2,528**	2,536	2,214	2,259	2,176

Per Unit Results – Produced Gas

Three Months Ended June 30

	Canada			**United States**		
($ per thousand cubic feet)	**2006**	**2006 vs 2005**	2005	**2006**	**2006 vs 2005**	2005
Price [(1)]	**$ 5.71**	**-6%**	$ 6.08	**$ 6.08**	**-8%**	$ 6.60
Expenses						
Production and mineral taxes	**0.08**	**-20%**	0.10	**0.22**	**-66%**	0.65
Transportation and selling	**0.35**	**-3%**	0.36	**0.50**	**19%**	0.42
Operating	**0.77**	**24%**	0.62	**0.70**	**40%**	0.50
Netback	**$ 4.51**	**-10%**	$ 5.00	**$ 4.66**	**-7%**	$ 5.03
Gas Sales Volumes *(MMcf/d)*	**2,192**	**2%**	2,151	**1,169**	**10%**	1,061

(1) Excludes the impact of realized financial hedging.

Per Unit Results – Produced Gas
Six Months Ended June 30

($ per thousand cubic feet)	Canada 2006	Canada 2006 vs 2005	Canada 2005	United States 2006	United States 2006 vs 2005	United States 2005
Price [1]	**$ 6.68**	**13%**	$ 5.89	**$ 6.88**	**9%**	$ 6.32
Expenses						
Production and mineral taxes	**0.13**	**30%**	0.10	**0.53**	**-16%**	0.63
Transportation and selling	**0.35**	**-5%**	0.37	**0.50**	**14%**	0.44
Operating	**0.78**	**22%**	0.64	**0.67**	**40%**	0.48
Netback	**$ 5.42**	**13%**	$ 4.78	**$ 5.18**	**9%**	$ 4.77
Gas Sales Volumes *(MMcf/d)*	**2,187**	**3%**	2,115	**1,165**	**9%**	1,064

(1) Excludes the impact of realized financial hedging.

Three Months Ended June 30

EnCana's North American natural gas price for the second quarter of 2006, excluding the impact of financial hedges, was $5.84 per Mcf, a decrease of 7 percent compared to the same period in 2005. North American realized financial commodity hedging gains on natural gas for the second quarter of 2006 were approximately $203 million or $0.66 per Mcf compared to losses of approximately $42 million or $0.14 per Mcf in the second quarter of 2005.

Natural gas per unit production and mineral taxes, which are generally calculated as a percentage of revenues, have decreased $0.02 per Mcf or 20 percent in Canada for the second quarter of 2006 compared to the same period in 2005, mainly due to lower natural gas prices offset partially by the higher value of the Canadian dollar. Natural gas per unit production and mineral taxes in the U.S. decreased $0.43 per Mcf or 66 percent in the second quarter of 2006 compared to the same period in 2005 mainly as a result of accrual to actual adjustments based on the receipt of ad valorem tax assessments for Colorado properties.

Natural gas per unit transportation and selling costs for the U.S. increased $0.08 per Mcf or 19 percent for the second quarter of 2006 compared to the same period in 2005 primarily as a result of higher transportation costs on operated wells from West Texas and certain Colorado properties.

Natural gas per unit operating expenses in Canada for the second quarter of 2006 were 24 percent or $0.15 per Mcf higher than the comparable period in 2005 as a result of increased industry activity and the higher value of the Canadian dollar. Natural gas per unit operating expenses in the U.S. increased 40 percent or $0.20 per Mcf for the second quarter of 2006 compared to the same period in 2005 mainly as a result of increased industry activity, higher water disposal costs, workovers and repairs and maintenance expenses primarily in the Piceance area.

Six Months Ended June 30

EnCana's North American natural gas price for the first six months of 2006, excluding the impact of financial hedges, was $6.75 per Mcf, an increase of 12 percent compared to the same period in 2005. North American realized financial commodity hedging gains on natural gas for the first half of 2006 were approximately $44 million or $0.07 per Mcf compared to gains of approximately $9 million or $0.02 per Mcf in the first six months of 2005.

Natural gas per unit production and mineral taxes increased $0.03 per Mcf or 30 percent in Canada for the first six months of 2006 compared to the same period in 2005, mainly due to higher natural gas prices, increased production from properties which are subject to freehold mineral tax and the higher value of the Canadian dollar. Natural gas per unit production and mineral taxes in the U.S. decreased $0.10 per Mcf or 16 percent in the first half of 2006 compared to the same period in 2005 mainly as a result of accrual to actual adjustments based on the receipt of ad valorem tax assessments for Colorado properties.

Natural gas per unit transportation and selling costs in Canada during the first half of 2006 decreased $0.02 per Mcf or 5 percent from the comparable period in 2005 mainly due to a higher proportion of Canadian gas volumes being sold in Canada, rather than shipped to and sold in the U.S. partially offset by the higher value of the Canadian dollar. Natural gas per unit transportation and selling costs for the U.S. increased $0.06 per Mcf or 14 percent for the first six months of 2006 compared to the same period of 2005 primarily as a result of higher transportation costs on operated wells from Fort Worth, certain Colorado properties and West Texas. Natural gas transportation and selling costs in the U.S. include $14 million for the one time charge for the buyout of a third party physical gas contract in the first quarter of 2006, which had been in place since 2000. The buyout amount has not been included in the per unit calculation.

Natural gas per unit operating expenses in Canada for the first half of 2006 were 22 percent or $0.14 per Mcf higher than the comparable period in 2005 as a result of increased industry activity and the higher value of the Canadian dollar. Natural gas per unit operating expenses in the U.S. increased 40 percent or $0.19 per Mcf for the first six months of 2006 compared to the same period in 2005 mainly as a result of increased industry activity, higher water disposal costs, repairs and maintenance and workover expenses primarily in the Piceance area.

Per Unit Results – Crude Oil

	North America					
	Three Months Ended June 30			Six Months Ended June 30		
($ per barrel)	**2006**	**2006 vs 2005**	2005	**2006**	**2006 vs 2005**	2005
Price (1)	**$ 51.62**	**73%**	$ 29.83	**$ 40.88**	**42%**	$ 28.73
Expenses						
Production and mineral taxes	**0.88**	**33%**	0.66	**0.77**	**31%**	0.59
Transportation and selling	**1.54**	**34%**	1.15	**1.39**	**9%**	1.27
Operating	**7.72**	**19%**	6.48	**7.42**	**19%**	6.26
Netback	**$ 41.48**	**93%**	$ 21.54	**$ 31.30**	**52%**	$ 20.61
Crude Oil Sales Volumes *(bbls/d)*	**129,070**	**-2%**	132,294	**133,695**	**2%**	131,564

(1) Excludes the impact of realized financial hedging.

Three Months Ended June 30

The increase in EnCana's North American crude oil price for the second quarter of 2006, excluding the impact of financial hedges, reflects the 64 percent increase in the benchmark WCS crude oil price compared to the same period in 2005. North American realized financial commodity hedging losses on crude oil were approximately $48 million or $3.43 per bbl of liquids for the second quarter of 2006 compared to losses of approximately $70 million or $4.88 per bbl of liquids for the comparable period in 2005.

Heavy oil sales in the second quarter of 2006 increased to 66 percent of total oil sales from 62 percent in the comparable period of 2005. This increase was mainly due to an increase in heavy oil production from Foster Creek offset by Pelican Lake reaching payout in April 2006. Dispositions of non-core conventional assets in June 2005 primarily producing light/medium oil also contributed to the increase.

North American crude oil per unit production and mineral taxes increased 33 percent or $0.22 per bbl in the second quarter of 2006 compared to the same period in 2005 primarily due to the impact of higher overall prices, increased production from the Weyburn property in Saskatchewan which is subject to freehold mineral tax and the higher value of the Canadian dollar.

North American crude oil per unit transportation and selling costs increased 34 percent or $0.39 per bbl in the second quarter of 2006 compared to the same period in 2005 primarily due to a higher proportion of Canadian heavy crude oil volumes being delivered to the U.S. Gulf Coast to capture higher selling prices and the higher value of the Canadian dollar.

North American crude oil per unit operating costs for the second quarter of 2006 increased 19 percent or $1.24 per bbl compared to the same period in 2005 mainly due to the higher value of the Canadian dollar and increased industry activity. The increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana's other properties, increased the overall crude oil per unit operating costs.

Six Months Ended June 30

The increase in EnCana's North American crude oil price for the first six months of 2006, excluding the impact of financial hedges, reflects the 38 percent increase in the benchmark WCS crude oil price compared to the same period in 2005. North American realized financial commodity hedging losses on crude oil were approximately $93 million or $3.27 per bbl of liquids for the first half of 2006 compared to losses of approximately $143 million or $5.03 per bbl of liquids for the comparable period in 2005.

Heavy oil sales in the first half of 2006 increased to 66 percent of total oil sales from 62 percent in the comparable period of 2005. This increase was mainly due to an increase in heavy oil production from the Foster Creek and Pelican Lake properties combined with dispositions of non-core conventional assets in June 2005 primarily producing light/medium oil. The increase in Pelican Lake production as a result of the positive waterflood response in 2005 has been partially offset as a result of the property reaching payout in April 2006.

North American crude oil per unit production and mineral taxes increased 31 percent or $0.18 per bbl in the first six months of 2006 compared to the same period in 2005 primarily due to the impact of higher overall prices, increased production from the Weyburn property in Saskatchewan which is subject to freehold mineral tax and Saskatchewan resource tax and the higher value of the Canadian dollar.

North American crude oil per unit transportation and selling costs increased 9 percent or $0.12 per bbl in the first six months of 2006 compared to the same period in 2005 primarily due to a higher proportion of Canadian heavy crude oil volumes being delivered to the U.S. Gulf Coast and the higher value of the Canadian dollar.

North American crude oil per unit operating costs for the first six months of 2006 increased 19 percent or $1.16 per bbl compared to the same period in 2005 mainly due to the higher value of the Canadian dollar, higher electricity, workovers and repairs and maintenance expenses. The increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana's other properties, increased the overall crude oil per unit operating costs.

Per Unit Results – NGLs

Three Months Ended June 30

	Canada			United States		
		2006 vs			2006 vs	
($ per barrel)	**2006**	**2005**	2005	**2006**	**2005**	2005
Price [1]	**$ 55.19**	**40%**	$ 39.55	**$ 58.25**	**30%**	$ 44.79
Expenses						
Production and mineral taxes	**-**	**-**	-	**2.60**	**-41%**	4.37
Transportation and selling	**0.73**	**87%**	0.39	**0.01**	**-**	0.01
Netback	**$ 54.46**	**39%**	$ 39.16	**$ 55.64**	**38%**	$ 40.41
NGLs Sales Volumes *(bbls/d)*	**11,607**	**-1%**	11,719	**12,793**	**-2%**	13,095

(1) Excludes the impact of realized financial hedging.

Per Unit Results – NGLs
Six Months Ended June 30

	Canada			United States		
		2006 vs			**2006 vs**	
($ per barrel)	**2006**	**2005**	2005	**2006**	**2005**	2005
Price [1]	**$ 51.98**	**31%**	$ 39.80	**$ 56.20**	**31%**	$ 42.76
Expenses						
Production and mineral taxes	**-**	**-**	-	**3.86**	**-10%**	4.28
Transportation and selling	**0.67**	**81%**	0.37	**0.01**	**-**	0.01
Netback	**$ 51.31**	**30%**	$ 39.43	**$ 52.33**	**36%**	$ 38.47
NGLs Sales Volumes *(bbls/d)*	**11,805**	**1%**	11,705	**12,605**	**-9%**	13,876

(1) Excludes the impact of realized financial hedging.

Three Months Ended June 30

The increase in NGLs realized prices in the second quarter of 2006 compared to the same period in 2005 generally correlates with higher WTI oil prices.

U.S. NGLs per unit production and mineral taxes in the U.S. decreased 41 percent or $1.77 per bbl in the second quarter of 2006 compared to the same period in 2005 mainly as a result of accrual to actual adjustments based on the receipt of ad valorem tax assessments for Colorado properties.

Six Months Ended June 30

The increase in NGLs realized prices in the first half of 2006 compared to the same period in 2005 generally correlates with higher WTI oil prices.

U.S. NGLs per unit production and mineral taxes in the U.S. decreased 10 percent or $0.42 per bbl in the first half of 2006 compared to the same period in 2005 mainly as a result of accrual to actual adjustments based on the receipt of ad valorem tax assessments for Colorado properties.

U.S. NGLs sales volumes decreased 9 percent as a result of natural declines at certain Colorado properties which have a high liquids component.

Upstream Depreciation, Depletion and Amortization

DD&A expenses in the first six months of 2006 increased $204 million or 16 percent from the same period in 2005 for the following reasons:

- North American sales volumes increased 4 percent; and
- Unit of production DD&A rates were $1.92 per Mcfe in the first half of 2006 compared to $1.73 per Mcfe in the same period in 2005. Rates were higher in the first six months of 2006 compared to the same period of 2005 as a result of increased future development costs and the higher value of the Canadian dollar partially reduced by the effect of the Gulf of Mexico sale in May 2005.

Market Optimization

Financial Results ($ millions)	**Three Months Ended June 30**		**Six Months Ended June 30**	
	2006	2005	**2006**	2005
Revenues	**$ 825**	$ 844	**$ 1,541**	$ 1,738
Expenses				
Transportation and selling	**10**	4	**13**	6
Operating	**13**	18	**31**	29
Purchased product	**794**	821	**1,483**	1,700
Operating Cash Flow	**8**	1	**14**	3
Depreciation, depletion and amortization	**2**	3	**5**	5
Segment Income (Loss)	**$ 6**	$ (2)	**$ 9**	$ (2)

On January 1, 2006, EnCana adopted Emerging Issues Task Force ("EITF") Abstract No. 04-13 – Accounting for Purchases and Sales of Inventory with the Same Counterparty. The effect is to record purchases and sales of inventory that are entered into in contemplation of each other with the same counterparty on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the earnings of the reported periods. These purchases and sales are used to optimize transportation or fulfill marketing arrangements. As a result of the adoption of this policy, reported revenues and purchased product costs for the first half of 2006 included offsets of $1,641 million.

Corporate

Financial Results ($ millions)	**Three Months Ended June 30**		**Six Months Ended June 30**	
	2006	2005	**2006**	2005
Revenues	**$ 230**	$ 315	**$ 1,493**	$ (647)
Expenses				
Operating	**(1)**	1	**-**	(2)
Depreciation, depletion and amortization	**20**	18	**38**	35
Segment Income (Loss)	**$ 211**	$ 296	**$ 1,455**	$ (680)
Administrative	**75**	66	**133**	127
Interest, net	**83**	101	**171**	201
Accretion of asset retirement obligation	**12**	9	**24**	18
Foreign exchange (gain) loss, net	**(202)**	119	**(158)**	151
Stock-based compensation – options	**-**	4	**-**	8
(Gain) on dispositions	**(8)**	-	**(17)**	-

First half 2006 corporate revenues include $1,493 million in unrealized mark-to-market gains related to financial commodity hedge contracts compared with a $647 million unrealized mark-to-market loss in the same period in 2005.

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

($ millions)	Three Months Ended June 30 2006	Three Months Ended June 30 2005	Six Months Ended June 30 2006	Six Months Ended June 30 2005
Continuing Operations				
Natural Gas	**$ 195**	$ 261	**$ 1,472**	$ (564)
Crude Oil	**35**	54	**21**	(83)
	230	315	**1,493**	(647)
Expenses	**-**	1	**2**	(2)
	230	314	**1,491**	(645)
Income Tax Expense (Recovery)	**69**	113	**515**	(224)
Unrealized Mark-to-Market Gains (Losses)	**$ 161**	$ 201	**$ 976**	$ (421)

Price volatility has impacted net earnings as a result of EnCana's price risk management activities. On June 30, 2006 the forward price curve for the remainder of 2006 had increased from December 31, 2005 by 18 percent to $75.54 per bbl for WTI and decreased by 33 percent to $7.15 per Mcf for NYMEX gas.

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

Administrative expenses increased $9 million in the second quarter and $6 million for the six months ended June 30, 2006 compared to the same periods in 2005. The year-to-date increase is primarily due to the change in the U.S./Canadian dollar exchange rate of $11 million, partially offset by a decrease in administrative expenses. Administrative expenses in the first half of 2006 were $0.17 per Mcfe, unchanged from the same period in 2005.

Interest expense in the second quarter of 2006 decreased by $18 million as a result of lower outstanding debt primarily due to repayments with the proceeds received from the sale of the Ecuador and gas storage interests. EnCana's total long-term debt, including current portion, decreased by $944 million to $5,832 million at June 30, 2006 compared with $6,776 million at December 31, 2005. EnCana's 2006 year-to-date weighted average interest rate on outstanding debt was 5.6 percent, up from an average of approximately 5.4 percent in the same period in 2005 as a result of a higher proportion of fixed rate debt outstanding as well as increases in interest rates.

The foreign exchange gain of $158 million in the first half of 2006 is primarily due to the change in the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada and by other miscellaneous gains, offset by a foreign exchange loss on repayments of debt between EnCana and self-sustaining operations. Under Canadian GAAP, EnCana is required to translate long-term debt issued from Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting unrealized foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings. Other foreign exchange gains and losses result from the settlement of foreign currency transactions and the translation of EnCana's monetary assets and liabilities.

Income Tax

The effective tax rate for the six months ended June 2006 is 23.0 percent compared to 24.4 percent for the equivalent period in 2005. The decrease is largely due to a decrease in future income tax expense of $457 million as a result of reductions in the Canadian federal and Alberta corporate tax rates which were enacted in the second quarter of 2006. The Canadian federal tax rate is to be reduced by approximately three percentage points over the period 2008 - 2010. The Alberta tax rate has been reduced from 11.5 percent to 10.0 percent effective April 1, 2006.

Cash taxes included in cash flow for the first half of 2006 were $628 million compared to $280 million in the same period in 2005; an increase of $348 million due to the increased taxable income in 2006. In addition, in 2005, $591 million of additional cash tax was incurred in the second quarter that resulted from the disposition of the Gulf of Mexico operations and is included in investing activity in the statement of cash flows.

Further information regarding EnCana's effective tax rate can be found in Note 8 to the Interim Consolidated Financial Statements. Income tax is an annual calculation and EnCana's effective rate in any year is a function of the relationship between the amount of net earnings before income taxes for the year and the magnitude of the items representing "permanent differences" that are excluded from the earnings which are subject to tax, either current or future. There are a variety of items of this type, including:

- The effects of asset dispositions where the tax values of the assets sold differ from their accounting values;
- Adjustments for the impact of legislative tax changes which have a prospective impact on future income tax obligations;
- The non-taxable half of Canadian capital gains or losses; and
- Items such as resource allowance and non-deductible crown payments where the income tax treatment is different from the accounting treatment.

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

Capital Expenditures

Capital Summary

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2006**	2005	**2006**	2005
Upstream	**$ 1,607**	$ 1,321	**$ 3,511**	$ 2,778
Market Optimization	**9**	81	**38**	115
Corporate	**16**	9	**29**	15
Total Core Capital Expenditures	**1,632**	1,411	**3,578**	2,908
Acquisitions	**271**	26	**286**	38
Dispositions	**(2)**	(2,406)	**(257)**	(2,459)
Discontinued Operations	**(1,072)**	68	**(2,415)**	125
Net Capital Investment	**$ 829**	$ (901)	**$ 1,192**	$ 612

EnCana's capital investment was funded by cash flow and a portion of the proceeds from dispositions.

Upstream Capital Expenditures

Capital spending during the second quarter and first six months of 2006 was primarily focused on North American resource play drilling programs. Natural gas capital expenditures mainly related to continued development of the Company's key resource plays in Greater Sierra, Cutbank Ridge, Bighorn, CBM and Shallow Gas in Canada, and Jonah, Piceance, East Texas and Fort Worth in the United States. Crude oil capital spending was concentrated on expansion of the Company's SAGD projects located at Foster Creek and Christina Lake.

The $0.3 billion increase in Upstream core capital expenditures in the second quarter of 2006 compared to 2005 was primarily due to:

- Canadian core capital expenditures increased $0.1 billion to $0.9 billion mainly as a result of the change in the U.S./Canadian dollar exchange rate; and
- U.S. core capital expenditures increased $0.2 billion to $0.6 billion primarily due to higher drilling and completion costs at Fort Worth related to the development of the Barnett Shale play, increased activity at Jonah upon receipt of the Bureau of Land Management Record of Decision approving further development of the field and the drilling of several deep gas wells at the Deep Bossier play in East Texas.

The $0.7 billion increase in Upstream core capital expenditures for the first six months of 2006 compared to 2005 was primarily due to:

- Canadian core capital expenditures increased $0.4 billion to $2.3 billion. The increased expenditures were mainly due to the change in the U.S./Canadian dollar exchange rate, higher drilling and completion costs as a result of industry activity levels and higher facility costs relating to plant expansions at Foster Creek and Bighorn, construction of a new gas plant at Cutbank Ridge and increased well tie-ins; and
- U.S. core capital expenditures increased $0.3 billion to $1.2 billion primarily due to higher drilling and completion costs at Fort Worth related to the development of the Barnett Shale play, increased activity at Jonah upon receipt of the Bureau of Land Management Record of Decision approving further development of the field and the drilling of several deep gas wells at the Deep Bossier play in East Texas.

Market Optimization Capital Expenditures

Expenditures were mostly focused on the completion of construction for the Entrega Pipeline prior to the sale in February 2006.

Corporate Capital Expenditures

Corporate capital expenditures have generally been directed to business information systems and leasehold improvements. The increase in spending in 2006 includes certain lands purchased for the development of a Calgary office complex.

Acquisitions, Dispositions and Discontinued Operations

Acquisitions included minor property acquisitions in 2006 and 2005 while dispositions included the sale of the Entrega Pipeline in Colorado in 2006 and minor property dispositions in 2005.

Included in Discontinued Operations are the dispositions of EnCana's Ecuador and gas storage assets (discussed in the Discontinued Operations section of this MD&A) in 2006 with the proceeds reduced by capital spending prior to the sales.

Discontinued Operations

Discontinued operations in the Interim Consolidated Financial Statements include:

- Ecuador
- Midstream

EnCana's 2006 net earnings for the six months ended June 30 from discontinued operations were $566 million compared to $182 million in 2005 and includes realized financial hedge gains of $3 million after-tax and unrealized financial hedge gains of $14 million after-tax.

Ecuador

On February 28, 2006 EnCana completed the sale of its interests in Ecuador operations for $1.4 billion and recorded a loss on sale of $47 million. During the second quarter, the Government of Ecuador seized the Block 15 assets, in 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 Andes Petroleum Company. The purchaser requested payment and EnCana has accrued the maximum amount, calculated in accordance with the terms of the agreement, of approximately $265 million. At this point 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.

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	**2006**	2005
Sales Volumes				
Crude Oil *(bbls/d)*	**-**	73,176	**24,937**	72,833
($ millions)				
Net Earnings (Loss) from Discontinued Operations [1] [3]	**$ (232)**	$ 51	**$ (279)**	$ 131
Capital Investment [2]	**229**	53	**(1,116)**	100

(1) 2006 Net Loss is a result of the sale and the 2005 Net Earnings are the result of operations.

(2) Capital Investment in 2006 includes the net proceeds of disposition of $1.4 billion, reduced by the indemnity claim in the second quarter.

(3) In accordance with Canadian generally accepted accounting principles, DD&A expense for Ecuador has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

Midstream

On March 6, 2006 EnCana announced that it had reached an agreement to sell its gas storage business interests for approximately $1.5 billion. The sale, to a single producer, is subject to closing conditions and regulatory approvals and is expected to close in two stages. The first stage of the sale closed on May 12, 2006 for proceeds of approximately $1.3 billion. The second stage is expected to close following receipt of California regulatory approvals which are expected to be received later this year.

($ millions)	Three Months Ended June 30 2006	2005	Six Months Ended June 30 2006	2005
Net Earnings from Discontinued Operations [(1)]	$ 797	$ 12	**$ 847**	$ 49
Capital Investment	(1,301)	15	**(1,299)**	25

(1) In accordance with Canadian generally accepted accounting principles, DD&A expense for the natural gas storage business has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

2006 Midstream net earnings from discontinued operations mainly results from the gain on sale of the gas storage operations in May 2006 which totaled $814 million after-tax. The remaining earnings are from the natural gas storage operations for the first six months of the year. The 2005 comparative amounts also included the NGLs processing business, which was sold in December 2005.

Liquidity and Capital Resources

($ millions)	Three Months Ended June 30 2006	2005	Six Months Ended June 30 2006	2005
Net cash provided by (used in)				
Operating activities	**$ 2,325**	$ 881	**$ 4,622**	$ 2,799
Investing activities	**(1,166)**	579	**(1,363)**	(770)
Financing activities	**(1,230)**	(1,568)	**(3,111)**	(2,307)
Deduct: Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	-	(1)	-	(2)
Increase (decrease) in cash and cash equivalents	**$ (71)**	$ (107)	**$ 148**	$ (276)

Operating Activities

Cash flow from continuing operations was $1,839 million during the second quarter of 2006 compared to $1,502 million for the same period in 2005. On a year-to-date basis cash flow from continuing operations was $3,418 million compared to $2,749 million for the same period in 2005. This increase in cash flow from continuing operations in 2006 was primarily due to increased revenues driven by higher liquids prices and natural gas sales volumes partially reduced by increased expenses. Cash flow from continuing operations comprises most of EnCana’s cash provided by operating activities.

Investing Activities

Net cash of $1,166 million was used for investing activities in the second quarter of 2006, which includes $1,064 million of net cash received from discontinued operations, an increase of $1,745 million compared to the same period in 2005. The 2005 net cash provided by investing activities included proceeds generated by the sale of the Gulf of Mexico operations in the second quarter of 2005. Capital expenditures, including property acquisitions, increased $466 million for the three months ended June 30, 2006. On a year-to-date basis cash flow used in investing activities was $1,363 million compared to $770 million for the same period in 2005.

Financing Activities

Total long-term debt as at June 30, 2006, including current portion, was reduced by revolving long-term debt repayments of $982 million since December 31, 2005. EnCana’s net debt adjusted for working capital was $6,492 million as at June 30, 2006 compared with $7,970 million at December 31, 2005. During the first half of 2006, EnCana purchased 43.7 million of its Common Shares for a total consideration of $2,073 million. The working capital deficit at June 30, 2006 was $733 million compared to a deficit of $1,267 million as at December 31, 2005.

EnCana had available unused committed bank credit facilities in the amount of $4.1 billion and unused shelf prospectuses for up to $4.4 billion at June 30, 2006.

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor's has assigned a rating of A- with a 'Negative Outlook', Dominion Bond Rating Services has assigned a rating of A(low) with a 'Stable Trend' and Moody's has assigned a rating of Baa2 'Stable'.

Financial Metrics

	June 30 2006	December 31 2005
Net Debt to Capitalization	**26%**	33%
Net Debt to Adjusted EBITDA [1]	**0.6x**	1.1x

[1] Adjusted EBITDA is a non-GAAP measure that is defined as earnings from Continuing Operations before gain on disposition, 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.

Outstanding Share Data

(millions)	June 30 2006
Common shares outstanding, beginning of year	**854.9**
Issued under option plans	**4.6**
Shares purchased (Normal Course Issuer Bid)	**(43.7)**
Common shares outstanding, end of period	**815.8**
Weighted average common share outstanding – diluted	**855.4**

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. There were no Preferred Shares outstanding as at June 30, 2006.

Employees and directors have been granted options to purchase Common Shares under various plans. At June 30, 2006, 15.8 million options without Tandem Share Appreciation Rights ("TSAR") attached were outstanding, of which 15.4 million are exercisable.

Long-term incentives may be granted to EnCana employees in the form of stock options and Performance Share Units ("PSUs"). Stock options granted since 2004 have an associated TSAR attached and employees may elect to exercise either the stock option or the associated Share Appreciation Right ("SAR"). Stock option exercises result in the issuance of new Common Shares while TSAR exercises result in cash payments by the Company. PSUs will not result in the issuance of new Common Shares by the Company as shares are purchased through a trust for payment, should performance considerations be met.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under four consecutive NCIBs which commenced in October 2002 and may continue until October 30, 2006. EnCana is entitled to purchase for cancellation up to approximately 85.6 million Common Shares under the renewed NCIB which commenced on October 31, 2005 and will terminate not later than October 30, 2006. As of July 11, 2006 EnCana has purchased approximately 43.7 million Common Shares under this NCIB and has 815.8 million Common Shares outstanding. Shareholders may obtain a copy of the NCIB documents without charge at www.sedar.com or by contacting investor.relations@encana.com.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. These dividends totaled $146 million in the first half of 2006 and $110 million for the same period in 2005. These dividends were funded by cash flow.

Normal Course Issuer Bid

	Share Purchases			
	Three Months Ended June 30		Six Months Ended June 30	
(millions)	**2006**	2005	**2006**	2005
Bid expired October 2005	**-**	22.7	**-**	44.7
Bid expiring October 2006	**22.4**	-	**43.7**	-

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 $5,832 million at June 30, 2006 are $443 million in commitments related to Commercial Paper. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. Further details regarding EnCana's long-term debt are described in Note 9 to the Interim Consolidated Financial Statements.

As at June 30, 2006, 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 132 Bcf at a weighted average price of $3.91 per Mcf. At June 30, 2006 these transactions had an unrealized loss of $330 million.

Off-Balance Sheet Financing Arrangements

EnCana does not have any off-balance sheet financing arrangements that have or are reasonably likely to have an effect on its results of operations or financial condition.

Leases

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

Legal Proceedings

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

Discontinued Merchant Energy Operations

California

As disclosed previously, in July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation whereby WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws.

In the Gallo action, the decision dealing with the issue of whether the scope of the Federal Energy Regulatory Commission's exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims is on appeal to the United States Court of Appeals for the Ninth Circuit. The Gallo lawsuit is stayed pending this appeal.

Without admitting any liability in the lawsuits, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court subject to final documentation and approval by the San Diego Superior Court. The individual parties who had brought their own actions are not parties to this settlement. WD has also agreed to pay $2.4 million to settle the class action lawsuits filed in the United States District Court in California, without admitting any liability in the lawsuits, subject to final documentation and approval by the United States District Court.

New York

WD was a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD agreed to pay $8.2 million to settle the New York class action lawsuit. Final documentation and approval by the New York District Court have been obtained and WD has paid the stated settlement amount.

Based on the aforementioned settlements, a total of $31 million has been accrued. EnCana Corporation and WD intend to vigorously defend against the remaining 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.

Accounting Policies and Estimates

On January 1, 2006, the Company adopted EITF Abstract No. 04-13 – Accounting for Purchases and Sales of Inventory with the Same Counterparty. As of January 1, 2006, purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the net earnings of the reported periods.

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
- reputational risks

EnCana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk volatility, the Company has entered into various financial instrument agreements. EnCana does not use derivative financial instruments for speculative purposes. The details of these instruments, including any unrealized gains or losses, as of June 30, 2006, are disclosed in Note 14 to the Interim Consolidated Financial Statements.

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of price risk to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by EnCana are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

Commodity Price

To partially mitigate the natural gas commodity price risk, the Company entered into swaps which fix the AECO and NYMEX prices and collars and put options which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. Physical contracts relating to these activities had an unrecognized gain of $20 million at June 30, 2006.

EnCana has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company's proprietary production management. Physical contracts associated with this activity had an unrecognized gain of $29 million at June 30, 2006.

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, purchased call options to allow participation at higher WTI levels, three-way put spreads and put options.

Foreign Exchange

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, EnCana may enter into foreign exchange contracts. The Company also enters into foreign exchange contracts in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined.

EnCana also maintains a mix of both U.S. dollar and Canadian dollar debt which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company has entered into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

Interest Rates

The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. EnCana has entered into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

Credit Risk

EnCana is exposed to credit related losses in the event of default by counterparties. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties credit quality and transactions that are fully collateralized. A substantial portion of EnCana's accounts receivable is with customers in the oil and gas industry.

Operational Risks

EnCana mitigates operational risk through a number of policies and processes. As part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of their previous capital program to identify key learnings, which often includes operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues which had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback results are analyzed for EnCana's capital program with the results and identified learnings shared across the Company.

Projects include a Business Risk Burden that is intended to account for the unforeseen risks. The amount of Business Risk Burden that is used on a particular project depends on the project's history of Lookback results and the type of expenditure. A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

EnCana also partially mitigates operational risks by maintaining a comprehensive insurance program.

Environment, Health, Safety and Security Risks

These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, EnCana maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana's Board of Directors recommends approval of environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

Security risks are managed through a Security Program designed to protect EnCana's personnel and assets. EnCana has established an Investigations Committee with the mandate to address potential violations of Company policies and practices and an Integrity Hotline that can be used to raise any concerns regarding EnCana's operations.

Climate Change

The Kyoto protocol, ratified by the Canadian Federal Government in December 2002, came into force on February 16, 2005. The protocol commits Canada to reducing greenhouse gas emissions to 6 percent below 1990 levels over the period 2008 – 2012. There is currently no clear direction post 2012. The previous Federal Government released a framework outlining its Climate Change action plan on April 13, 2005. The plan as released contains few technical details regarding the implementation of the Government's greenhouse gas reduction strategy.

With the change in the Federal Government, EnCana is unable to predict the total impact of the potential regulations upon its business; however, it is possible that the Corporation could face increases in operating costs in order to comply with greenhouse gas emissions legislation. However, a July 16, 2005 Canada Gazette notice partially addressed the uncertainty associated with a greenhouse gas regulation for existing facilities by providing the oil and gas sector with limits on cost (a price assurance mechanism of C$15/tonne for compliance) and emission reductions targets that will not exceed 12 percent lower than business as usual levels of total covered emissions for a given sector. It also made a commitment to targets based on the "best available technology economically achievable" for new facilities. Based on these commitments and EnCana's activity on geological sequestration of CO2, we do not anticipate that the cost implications of government climate change plans will have a material impact on operations or future growth plans.

EnCana, via the Canadian Association of Petroleum Producers will continue to work with the Federal and Alberta Governments to develop an approach to deal with climate change issues which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's greenhouse gas emissions is available in the Corporate Responsibility Report that was published in the second quarter of 2006. The Report is available on www.encana.com.

Reputational Risks

EnCana takes a pro-active approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear procedures, guidelines and responsibility for identifying and managing these issues. Issues affecting or with the potential to affect EnCana's reputation are generally either emerging issues that can be identified early and then managed or unforeseen issues that arise unexpectedly and must be managed on an urgent basis.

Outlook

EnCana plans to continue to focus principally on growing natural gas production from unconventional resource plays in North America and developing its high quality in-situ oilsands resources. EnCana is continuing to evaluate marketing, development and other options that will help expand the development of the oilsands resources.

Volatility in crude oil prices is expected to continue throughout 2006 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. In the near term, the new pipeline capacity to the U.S. Gulf Coast should reduce the volatility on Canadian crude oil relative to world oil prices.

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 gas supply constrained situation in North America remains challenged by land access and regulatory issues.

The Company expects its 2006 core capital investment program to be funded from cash flow.

Proceeds from the sales of non-core assets are expected to be used for purchases of common shares under the Company's NCIB program and repayments of long-term 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: projections with respect to growth of natural gas production from unconventional resource plays and in-situ oilsands development; projected production volumes in 2006 for natural gas, crude oil and NGLs in Canada and the United States; projections relating to the volatility of crude oil prices in 2006 and beyond and the reasons therefor; potential marketing, development and other options that may expand oilsands resources development; the Company's projected capital investment levels for 2006 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 execution of share purchases under its Normal Course Issuer Bid; the Company's defence of lawsuits; the impact of the Kyoto Accord on operating costs; the adequacy of the Company's provision for taxes; the Company's plans to divest of its remaining natural gas storage assets in California and the date for receipt of regulatory approvals in respect thereof; the Company's plans to divest certain interests offshore Brazil and the timing therefor; projections relating to the use of proceeds therefrom, including debt repayment and purchases under its Normal Course Issuer Bid; the impact of new pipeline capacity to the U.S. Gulf Coast on future Canadian crude oil prices; projections that the Company's Bankers'

Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; the projected amounts of and likelihood of making certain indemnity payments in respect of the Ecuador share sale agreements 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, 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; risks associated with technology; its ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and except as required by law EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

OIL AND GAS INFORMATION

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

Crude Oil, Natural Gas Liquids and Natural Gas Conversions

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

Resource Play, Estimated Ultimate Recovery, and Unbooked Resource Potential

EnCana uses the terms resource play, estimated ultimate recovery and unbooked resource potential. 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. EnCana defines Unbooked Resource Potential as quantities of oil and gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play potential and areal extent. Consequently, EnCana's unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

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 $0.88 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, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and Adjusted EBITDA and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company’s liquidity and its ability to generate funds to finance its operations. Management’s use of these measures has been disclosed further in this MD&A as these measures are discussed and presented.

References to EnCana

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

ADDITIONAL INFORMATION

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

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*

($ millions, except per share amounts)		Three Months Ended June 30, **2006**	2005	Six Months Ended June 30, **2006**	2005
REVENUES, NET OF ROYALTIES	*(Note 3)*				
Upstream		**$ 2,749**	$ 2,227	**$ 5,440**	$ 4,333
Market Optimization		**825**	844	**1,541**	1,738
Corporate - Unrealized gain (loss) on risk management		**230**	315	**1,493**	(647)
		3,804	3,386	**8,474**	5,424
EXPENSES	*(Note 3)*				
Production and mineral taxes		**51**	97	**190**	184
Transportation and selling		**152**	130	**304**	263
Operating		**395**	315	**807**	615
Purchased product		**794**	821	**1,483**	1,700
Depreciation, depletion and amortization		**790**	669	**1,555**	1,348
Administrative		**75**	66	**133**	127
Interest, net	*(Note 6)*	**83**	101	**171**	201
Accretion of asset retirement obligation	*(Note 10)*	**12**	9	**24**	18
Foreign exchange (gain) loss, net	*(Note 7)*	**(202)**	119	**(158)**	151
Stock-based compensation - options		**-**	4	**-**	8
(Gain) on dispositions		**(8)**	-	**(17)**	-
		2,142	2,331	**4,492**	4,615
NET EARNINGS BEFORE INCOME TAX		**1,662**	1,055	**3,982**	809
Income tax expense	*(Note 8)*	**69**	281	**917**	197
NET EARNINGS FROM CONTINUING OPERATIONS		**1,593**	774	**3,065**	612
NET EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 4)*	**564**	65	**566**	182
NET EARNINGS		**$ 2,157**	$ 839	**$ 3,631**	$ 794
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 13)*				
Basic		**$ 1.92**	$ 0.89	**$ 3.65**	$ 0.69
Diluted		**$ 1.88**	$ 0.87	**$ 3.58**	$ 0.68
NET EARNINGS PER COMMON SHARE	*(Note 13)*				
Basic		**$ 2.60**	$ 0.96	**$ 4.33**	$ 0.90
Diluted		**$ 2.55**	$ 0.94	**$ 4.24**	$ 0.88

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Six Months Ended June 30, **2006**	2005
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 9,481**	$ 7,935
Net Earnings		**3,631**	794
Dividends on Common Shares		**(146)**	(110)
Charges for Normal Course Issuer Bid	*(Note 11)*	**(1,700)**	(1,124)
Charges for Shares Repurchased and Held		**-**	(147)
RETAINED EARNINGS, END OF PERIOD		**$ 11,266**	$ 7,348

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		As at June 30, 2006	As at December 31, 2005
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 253**	$ 105
Accounts receivable and accrued revenues		**1,518**	1,851
Risk management	*(Note 14)*	**965**	495
Inventories		**109**	103
Assets of discontinued operations	*(Note 4)*	**195**	1,050
		3,040	3,604
Property, Plant and Equipment, net	*(Note 3)*	**27,855**	24,881
Investments and Other Assets		**546**	496
Risk Management	*(Note 14)*	**313**	530
Assets of Discontinued Operations	*(Note 4)*	**-**	2,113
Goodwill		**2,618**	2,524
	(Note 3)	**$ 34,372**	$ 34,148
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,292**	$ 2,741
Income tax payable		**875**	392
Risk management	*(Note 14)*	**170**	1,227
Liabilities of discontinued operations	*(Note 4)*	**363**	438
Current portion of long-term debt	*(Note 9)*	**73**	73
		3,773	4,871
Long-Term Debt	*(Note 9)*	**5,759**	6,703
Other Liabilities		**87**	93
Risk Management	*(Note 14)*	**18**	102
Asset Retirement Obligation	*(Note 10)*	**906**	816
Liabilities of Discontinued Operations	*(Note 4)*	**-**	267
Future Income Taxes		**5,764**	5,289
		16,307	18,141
Shareholders' Equity			
Share capital	*(Note 11)*	**4,859**	5,131
Paid in surplus		**140**	133
Retained earnings		**11,266**	9,481
Foreign currency translation adjustment		**1,800**	1,262
		18,065	16,007
		$ 34,372	$ 34,148

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

		Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)		**2006**	2005	**2006**	2005
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 1,593**	$ 774	**$ 3,065**	$ 612
Depreciation, depletion and amortization		**790**	669	**1,555**	1,348
Future income taxes	*(Note 8)*	**(228)**	(379)	**289**	(674)
Cash tax on sale of assets		**-**	591	**-**	591
Unrealized (gain) loss on risk management	*(Note 14)*	**(230)**	(314)	**(1,491)**	645
Unrealized foreign exchange (gain) loss		**(143)**	105	**(83)**	123
Accretion of asset retirement obligation	*(Note 10)*	**12**	9	**24**	18
(Gain) on dispositions		**(8)**	-	**(17)**	-
Other		**53**	47	**76**	86
Cash flow from continuing operations		**1,839**	1,502	**3,418**	2,749
Cash flow from discontinued operations		**(24)**	70	**88**	236
Cash flow		**1,815**	1,572	**3,506**	2,985
Net change in other assets and liabilities		**38**	(16)	**27**	(14)
Net change in non-cash working capital from continuing operations		**1,508**	(687)	**3,552**	(73)
Net change in non-cash working capital from discontinued operations		**(1,036)**	12	**(2,463)**	(99)
		2,325	881	**4,622**	2,799
INVESTING ACTIVITIES					
Capital expenditures	*(Note 3)*	**(1,903)**	(1,437)	**(3,864)**	(2,946)
Proceeds on disposal of assets	*(Note 5)*	**2**	2,406	**257**	2,459
Cash tax on sale of assets		**-**	(591)	**-**	(591)
Net change in investments and other		**(59)**	(27)	**18**	(8)
Net change in non-cash working capital from continuing operations		**(270)**	290	**(151)**	451
Discontinued operations		**1,064**	(62)	**2,377**	(135)
		(1,166)	579	**(1,363)**	(770)
FINANCING ACTIVITIES					
Net (repayment) of revolving long-term debt		**(101)**	(682)	**(982)**	(715)
Repayment of long-term debt		**-**	-	**-**	(1)
Issuance of common shares	*(Note 11)*	**49**	83	**101**	184
Purchase of common shares	*(Note 11)*	**(1,095)**	(902)	**(2,073)**	(1,662)
Dividends on common shares		**(82)**	(66)	**(146)**	(110)
Other		**(1)**	(1)	**(11)**	(3)
		(1,230)	(1,568)	**(3,111)**	(2,307)
DEDUCT: FOREIGN EXCHANGE (GAIN) ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**-**	(1)	**-**	(2)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**(71)**	(107)	**148**	(276)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**324**	424	**105**	593
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 253**	$ 317	**$ 253**	$ 317

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. The Company is in the business of exploration for, and production and marketing of, natural gas, crude oil and natural gas liquids, as well as natural gas storage, natural gas liquids processing 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, 2005, 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, 2005.

2. CHANGE IN ACCOUNTING POLICIES AND PRACTICES

On January 1, 2006, the Company adopted Emerging Issues Task Force ("EITF") Abstract No. 04-13 - Accounting for Purchases and Sales of Inventory with the Same Counterparty. As of January 1, 2006, purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the net earnings of the reported periods.

3. SEGMENTED INFORMATION

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

- **Upstream** includes the Company’s 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. Frontier and international new venture exploration is mainly focused on opportunities in Chad, Brazil, the Middle East, Greenland and France.

- **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 Upstream segment. 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 instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization purchases substantially all of the Company's North American Upstream production for sale 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 4.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

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

	Upstream		Market Optimization	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 2,749**	$ 2,227	**$ 825**	$ 844
Expenses				
Production and mineral taxes	**51**	97	**-**	-
Transportation and selling	**142**	126	**10**	4
Operating	**383**	296	**13**	18
Purchased product	**-**	-	**794**	821
Depreciation, depletion and amortization	**768**	648	**2**	3
Segment Income (Loss)	**$ 1,405**	$ 1,060	**$ 6**	$ (2)

	Corporate *		Consolidated	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 230**	$ 315	**$ 3,804**	$ 3,386
Expenses				
Production and mineral taxes	**-**	-	**51**	97
Transportation and selling	**-**	-	**152**	130
Operating	**(1)**	1	**395**	315
Purchased product	**-**	-	**794**	821
Depreciation, depletion and amortization	**20**	18	**790**	669
Segment Income	**$ 211**	$ 296	**1,622**	1,354
Administrative			**75**	66
Interest, net			**83**	101
Accretion of asset retirement obligation			**12**	9
Foreign exchange loss (gain), net			**(202)**	119
Stock-based compensation - options			**-**	4
(Gain) on divestitures			**(8)**	-
			(40)	299
Net Earnings Before Income Tax			**1,662**	1,055
Income tax expense			**69**	281
Net Earnings From Continuing Operations			**$ 1,593**	$ 774

* For the three months ended June 30, the pre-tax unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see Note 14):

	2006	2005
Revenues, Net of Royalties - Corporate	**$ 230**	$ 315
Operating Expenses and Other - Corporate	**-**	(1)
Total Unrealized Gain on Risk Management before-tax - Continuing Operations	**$ 230**	$ 314

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

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

Upstream	Canada		United States	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 1,911**	$ 1,514	**$ 766**	$ 655
Expenses				
Production and mineral taxes	**24**	29	**27**	68
Transportation and selling	**90**	85	**52**	41
Operating	**245**	200	**75**	48
Depreciation, depletion and amortization	**539**	469	**216**	171
Segment Income	**$ 1,013**	$ 731	**$ 396**	$ 327

	Other		Total Upstream	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 72**	$ 58	**$ 2,749**	$ 2,227
Expenses				
Production and mineral taxes	**-**	-	**51**	97
Transportation and selling	**-**	-	**142**	126
Operating	**63**	48	**383**	296
Depreciation, depletion and amortization	**13**	8	**768**	648
Segment Income (Loss)	**$ (4)**	$ 2	**$ 1,405**	$ 1,060

Upstream Geographic and Product Information (Continuing Operations) *(For the three months ended June 30)*

Produced Gas	Produced Gas					
	Canada		United States		Total	
	2006	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ 1,296**	$ 1,184	**$ 695**	$ 601	**$ 1,991**	$ 1,785
Expenses						
Production and mineral taxes	**15**	21	**23**	62	**38**	83
Transportation and selling	**71**	71	**52**	41	**123**	112
Operating	**153**	122	**75**	48	**228**	170
Operating Cash Flow	**$ 1,057**	$ 970	**$ 545**	$ 450	**$ 1,602**	$ 1,420

Oil & NGLs	Oil & NGLs					
	Canada		United States		Total	
	2006	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ 615**	$ 330	**$ 71**	$ 54	**$ 686**	$ 384
Expenses						
Production and mineral taxes	**9**	8	**4**	6	**13**	14
Transportation and selling	**19**	14	**-**	-	**19**	14
Operating	**92**	78	**-**	-	**92**	78
Operating Cash Flow	**$ 495**	$ 230	**$ 67**	$ 48	**$ 562**	$ 278

Other & Total Upstream	Other		Total Upstream	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 72**	$ 58	**$ 2,749**	$ 2,227
Expenses				
Production and mineral taxes	**-**	-	**51**	97
Transportation and selling	**-**	-	**142**	126
Operating	**63**	48	**383**	296
Operating Cash Flow	**$ 9**	$ 10	**$ 2,173**	$ 1,708

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

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

	Upstream		Market Optimization	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 5,440**	$ 4,333	**$ 1,541**	$ 1,738
Expenses				
Production and mineral taxes	**190**	184	**-**	-
Transportation and selling	**291**	257	**13**	6
Operating	**776**	588	**31**	29
Purchased product	**-**	-	**1,483**	1,700
Depreciation, depletion and amortization	**1,512**	1,308	**5**	5
Segment Income (Loss)	**$ 2,671**	$ 1,996	**$ 9**	$ (2)

	Corporate *		Consolidated	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 1,493**	$ (647)	**$ 8,474**	$ 5,424
Expenses				
Production and mineral taxes	**-**	-	**190**	184
Transportation and selling	**-**	-	**304**	263
Operating	**-**	(2)	**807**	615
Purchased product	**-**	-	**1,483**	1,700
Depreciation, depletion and amortization	**38**	35	**1,555**	1,348
Segment Income (Loss)	**$ 1,455**	$ (680)	**4,135**	1,314
Administrative			**133**	127
Interest, net			**171**	201
Accretion of asset retirement obligation			**24**	18
Foreign exchange (gain) loss, net			**(158)**	151
Stock-based compensation - options			**-**	8
(Gain) on dispositions			**(17)**	-
			153	505
Net Earnings Before Income Tax			**3,982**	809
Income tax expense			**917**	197
Net Earnings From Continuing Operations			**$ 3,065**	$ 612

* For the six months ended June 30, the pre-tax unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see Note 14):

	2006	2005
Revenues, Net of Royalties - Corporate	**$ 1,493**	$ (647)
Operating Expenses and Other - Corporate	**(2)**	2
Total Unrealized Gain (Loss) on Risk Management before-tax - Continuing Operations	**$ 1,491**	$ (645)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

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

Upstream	Canada		United States	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 3,741**	$ 2,940	**$ 1,545**	$ 1,274
Expenses				
Production and mineral taxes	**69**	51	**121**	133
Transportation and selling	**173**	172	**118**	85
Operating	**487**	392	**143**	92
Depreciation, depletion and amortization	**1,065**	931	**426**	359
Segment Income	**$ 1,947**	$ 1,394	**$ 737**	$ 605

Transportation and selling for the United States includes a one time payment in the first quarter of 2006 of $14 million to terminate a long-term physical delivery contract.

	Other		Total Upstream	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 154**	$ 119	**$ 5,440**	$ 4,333
Expenses				
Production and mineral taxes	**-**	-	**190**	184
Transportation and selling	**-**	-	**291**	257
Operating	**146**	104	**776**	588
Depreciation, depletion and amortization	**21**	18	**1,512**	1,308
Segment Income (Loss)	**$ (13)**	$ (3)	**$ 2,671**	$ 1,996

Upstream Geographic and Product Information (Continuing Operations) *(For the six months ended June 30)*

	Produced Gas					
	Canada		United States		Total	
	2006	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ 2,737**	$ 2,317	**$ 1,413**	$ 1,165	**$ 4,150**	$ 3,482
Expenses						
Production and mineral taxes	**51**	37	**112**	121	**163**	158
Transportation and selling	**138**	141	**118**	85	**256**	226
Operating	**306**	243	**143**	92	**449**	335
Operating Cash Flow	**$ 2,242**	$ 1,896	**$ 1,040**	$ 867	**$ 3,282**	$ 2,763

Transportation and selling for the United States includes a one time payment in the first quarter of 2006 of $14 million to terminate a long-term physical delivery contract.

	Oil & NGLs					
	Canada		United States		Total	
	2006	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ 1,004**	$ 623	**$ 132**	$ 109	**$ 1,136**	$ 732
Expenses						
Production and mineral taxes	**18**	14	**9**	12	**27**	26
Transportation and selling	**35**	31	**-**	-	**35**	31
Operating	**181**	149	**-**	-	**181**	149
Operating Cash Flow	**$ 770**	$ 429	**$ 123**	$ 97	**$ 893**	$ 526

	Other		Total Upstream	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 154**	$ 119	**$ 5,440**	$ 4,333
Expenses				
Production and mineral taxes	**-**	-	**190**	184
Transportation and selling	**-**	-	**291**	257
Operating	**146**	104	**776**	588
Operating Cash Flow	**$ 8**	$ 15	**$ 4,183**	$ 3,304

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

Capital Expenditures (Continuing Operations)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
Upstream Core Capital				
Canada	**$ 953**	$ 830	**$ 2,302**	$ 1,871
United States	**633**	475	**1,170**	878
Other Countries	**21**	16	**39**	29
	1,607	1,321	**3,511**	2,778
Upstream Acquisition Capital				
Canada	**21**	20	**29**	23
United States	**250**	6	**257**	15
	271	26	**286**	38
Market Optimization	**9**	81	**38**	115
Corporate	**16**	9	**29**	15
Total	**$ 1,903**	$ 1,437	**$ 3,864**	$ 2,946

Property, Plant and Equipment and Total Assets

		Property, Plant and Equipment As at		Total Assets As at	
		June 30, 2006	December 31, 2005	**June 30, 2006**	December 31, 2005
Upstream		**$ 27,418**	$ 24,247	**$ 31,827**	$ 28,858
Market Optimization		**162**	371	**413**	597
Corporate		**275**	263	**1,937**	1,530
Assets of Discontinued Operations	*(Note 4)*			**195**	3,163
Total		**$ 27,855**	$ 24,881	**$ 34,372**	$ 34,148

4. DISCONTINUED OPERATIONS

Midstream

On December 13, 2005, EnCana completed the sale of its Midstream natural gas liquids processing operations for total proceeds of $625 million (C$720 million). The natural gas liquids processing operations included various interests in a number of processing and related facilities as well as a marketing entity. A gain on sale of approximately $370 million, after-tax, was recorded.

During the fourth quarter of 2005, EnCana decided to divest of its natural gas storage operations. EnCana's natural gas storage operations include the 100 percent interest in the AECO storage facility as well as facilities in the United States. On March 6, 2006, EnCana announced that it had reached an agreement to sell the gas storage operations for $1.5 billion. The sale, to a single purchaser, which is subject to closing conditions and applicable regulatory approvals, is expected to close in two stages. On May 12, 2006, the first stage of the sale was closed for proceeds of $1.3 billion. The second stage will close following receipt of regulatory approvals, expected to be later in 2006.

Ecuador

At December 31, 2004, EnCana decided to divest of its Ecuador operations and such operations have been accounted for as discontinued operations. EnCana's Ecuador operations include the 100 percent working interest in the Tarapoa Block, majority operating interest in Blocks 14, 17 and Shiripuno, the non-operated economic interest in relation to Block 15 and the 36.3 percent indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd. ("OCP"), which is the owner of a crude oil pipeline in Ecuador that ships crude oil from the producing areas of Ecuador to an export marine terminal. The Company is a shipper on the OCP Pipeline and pays commercial rates for tariffs. The majority of the Company's crude oil produced in Ecuador is sold to a single marketing company. Payments are secured by letters of credit from a major financial institution which has a high quality investment grade credit rating.

In accordance with Canadian generally accepted accounting principles, depletion, depreciation and amortization expense has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

On February 28, 2006, EnCana completed the sale of its interest in its Ecuador operations for $1.4 billion before indemnifications which are discussed further in this note.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. DISCONTINUED OPERATIONS (continued)

Consolidated Statement of Earnings

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

	For the three months ended June 30,							
	Ecuador		United Kingdom		Midstream		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ -**	$ 241	**$ -**	$ -	**$ 28**	$ 195	**$ 28**	$ 436
Expenses								
Production and mineral taxes	**-**	30	**-**	-	**-**	-	**-**	30
Transportation and selling	**-**	16	**-**	-	**-**	1	**-**	17
Operating	**-**	34	**-**	-	**10**	58	**10**	92
Purchased product	**-**	-	**-**	-	**-**	112	**-**	112
Depreciation, depletion and amortization	**-**	-	**-**	-	**-**	6	**-**	6
Administrative	**-**	-	**-**	-	**-**	-	**-**	-
Interest, net	**-**	-	**-**	-	**-**	-	**-**	-
Accretion of asset retirement obligation	**-**	1	**-**	-	**-**	-	**-**	1
Foreign exchange (gain) loss, net	**-**	1	**(1)**	(3)	**9**	-	**8**	(2)
(Gain) loss on discontinuance	**232**	-	**-**	-	**(768)**	-	**(536)**	-
	232	82	**(1)**	(3)	**(749)**	177	**(518)**	256
Net Earnings (Loss) Before Income Tax	**(232)**	159	**1**	3	**777**	18	**546**	180
Income tax expense (recovery)	**-**	108	**2**	1	**(20)**	6	**(18)**	115
Net Earnings (Loss) From Discontinued Operations	**$ (232)**	$ 51	**$ (1)**	$ 2	**$ 797**	$ 12	**$ 564**	$ 65

	For the six months ended June 30,							
	Ecuador		United Kingdom		Midstream		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties *	**$ 200**	$ 432	**$ -**	$ -	**$ 463**	$ 818	**$ 663**	$ 1,250
Expenses								
Production and mineral taxes	**23**	52	**-**	-	**-**	-	**23**	52
Transportation and selling	**10**	31	**-**	-	**-**	4	**10**	35
Operating	**25**	62	**-**	-	**29**	130	**54**	192
Purchased product	**-**	-	**-**	-	**354**	596	**354**	596
Depreciation, depletion and amortization	**84**	-	**-**	-	**-**	13	**84**	13
Administrative	**-**	-	**-**	-	**-**	-	**-**	-
Interest, net	**(2)**	-	**-**	-	**-**	-	**(2)**	-
Accretion of asset retirement obligation	**-**	1	**-**	-	**-**	-	**-**	1
Foreign exchange (gain) loss, net	**1**	1	**-**	(3)	**9**	(1)	**10**	(3)
(Gain) loss on discontinuance	**279**	-	**-**	-	**(768)**	-	**(489)**	-
	420	147	**-**	(3)	**(376)**	742	**44**	886
Net Earnings (Loss) Before Income Tax	**(220)**	285	**-**	3	**839**	76	**619**	364
Income tax expense (recovery)	**59**	154	**2**	1	**(8)**	27	**53**	182
Net Earnings (Loss) From Discontinued Operations	**$ (279)**	$ 131	**$ (2)**	$ 2	**$ 847**	$ 49	**$ 566**	$ 182

* Revenues, net of royalties in Ecuador include realized losses of $1 million related to derivative financial instruments. In 2005, revenues, net of royalties included realized losses of $55 million and unrealized mark-to-market gains of $11 million.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. DISCONTINUED OPERATIONS (continued)

Consolidated Balance Sheet

The impact of the discontinued operations in the Consolidated Balance Sheet is as follows:

	As at							
	June 30, 2006				December 31, 2005			
	Ecuador	United Kingdom	Midstream	Total	Ecuador	United Kingdom	Midstream	Total
Assets								
Cash and cash equivalents	**$ -**	**$ 6**	**$ (13)**	**$ (7)**	$ 207	$ 8	$ (7)	$ 208
Accounts receivable and accrued revenues	**-**	**-**	**22**	**22**	137	-	271	408
Risk management	**-**	**-**	**2**	**2**	-	-	21	21
Inventories	**-**	**-**	**19**	**19**	23	-	390	413
	-	**6**	**30**	**36**	367	8	675	1,050
Property, plant and equipment, net	**1**	**-**	**158**	**159**	1,166	-	520	1,686
Investments and other assets	**-**	**-**	**-**	**-**	360	-	-	360
Goodwill	**-**	**-**	**-**	**-**	-	-	67	67
	$ 1	**$ 6**	**$ 188**	**$ 195**	$ 1,893	$ 8	$ 1,262	$ 3,163
Liabilities								
Accounts payable and accrued liabilities	**$ 265**	**$ 27**	**$ 15**	**$ 307**	$ 91	$ 27	$ 49	$ 167
Income tax payable	**-**	**7**	**27**	**34**	184	6	40	230
Risk management	**-**	**-**	**-**	**-**	-	-	41	41
	265	**34**	**42**	**341**	275	33	130	438
Asset retirement obligation	**-**	**-**	**-**	**-**	21	-	-	21
Future income taxes	**-**	**-**	**22**	**22**	162	(2)	86	246
	265	**34**	**64**	**363**	458	31	216	705
Net Assets of Discontinued Operations	**$ (264)**	**$ (28)**	**$ 124**	**$ (168)**	$ 1,435	$ (23)	$ 1,046	$ 2,458

Contingencies

EnCana has 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, the Government of Ecuador seized the Block 15 assets, in which EnCana previously held a 40 percent economic interest, from the operator which is an event requiring indemnification under terms of EnCana's sale agreement with Andes Petroleum Company. The purchaser requested payment and EnCana has accrued the maximum amount, calculated in accordance with the terms of the agreements, of approximately $265 million. At this point 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.

5. DIVESTITURES

Total proceeds received on sale of assets and investments was $257 million (2005 - $2,459 million) as described below:

Upstream

In 2006, the Company has completed the disposition of mature conventional oil and natural gas assets for proceeds of $13 million (2005 - $408 million).

In May 2005, the Company completed the sale of its Gulf of Mexico assets for approximately $2.1 billion resulting in net proceeds of approximately $1.5 billion after deducting $591 million in tax plus other adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

Market Optimization

In February 2006, the Company sold its investment in Entrega Gas Pipeline LLC for approximately $244 million.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. INTEREST, NET

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Interest Expense - Long-Term Debt	**$ 87**	$ 105	**$ 181**	$ 206
Interest Expense - Other	**5**	3	**10**	7
Interest Income	**(9)**	(7)	**(20)**	(12)
	$ 83	$ 101	**$ 171**	$ 201

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Unrealized Foreign Exchange (Gain) Loss on Translation of U.S. Dollar Debt Issued in Canada	**$ (163)**	$ 47	**$ (159)**	$ 65
Other Foreign Exchange (Gain) Loss	**(39)**	72	**1**	86
	$ (202)	$ 119	**$ (158)**	$ 151

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Current				
Canada	**$ 281**	$ 110	**$ 589**	$ 282
United States	**13**	559	**36**	591
Other	**3**	(9)	**3**	(2)
Total Current Tax	**297**	660	**628**	871
Future	**(228)**	(379)	**289**	(674)
	$ 69	$ 281	**$ 917**	$ 197

Current income tax in the United States for the six months ended June 30, 2005 relates to income tax on the sale of the Gulf of Mexico assets.

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

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Net Earnings Before Income Tax	**$ 1,662**	$ 1,055	**$ 3,982**	$ 809
Canadian Statutory Rate	**34.8%**	37.9%	**34.8%**	37.9%
Expected Income Tax	**578**	399	**1,384**	307
Effect on Taxes Resulting from:				
Non-deductible Canadian crown payments	**21**	44	**52**	86
Canadian resource allowance	**1**	(42)	**(19)**	(90)
Canadian resource allowance on unrealized risk management losses	**1**	(5)	**1**	13
Statutory and other rate differences	**(1)**	(67)	**(17)**	(80)
Effect of tax rate changes*	**(457)**	-	**(457)**	-
Non-taxable capital (gains) losses	**(32)**	11	**(33)**	16
Tax basis retained on dispositions	**-**	(68)	**-**	(68)
Large corporations tax	**(1)**	-	**-**	4
Other	**(41)**	9	**6**	9
	$ 69	$ 281	**$ 917**	$ 197
Effective Tax Rate	**4.2%**	26.6%	**23.0%**	24.4%

*During the second quarter, the Canadian federal and Alberta governments substantively enacted income tax rate reductions.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. LONG-TERM DEBT

	As at June 30, 2006	As at December 31, 2005
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 443**	$ 1,425
Unsecured notes	**830**	793
	1,273	2,218
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**-**	-
Unsecured notes	**4,494**	4,494
	4,494	4,494
Increase in Value of Debt Acquired *	**65**	64
Current Portion of Long-Term Debt	**(73)**	(73)
	$ 5,759	$ 6,703

* 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.

10. 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 properties:

	As at June 30, 2006	As at December 31, 2005
Asset Retirement Obligation, Beginning of Year	**$ 816**	$ 611
Liabilities Incurred	**37**	77
Liabilities Settled	**(26)**	(42)
Liabilities Disposed	**-**	(23)
Change in Estimated Future Cash Flows	**16**	135
Accretion Expense	**24**	37
Other	**39**	21
Asset Retirement Obligation, End of Period	**$ 906**	$ 816

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. SHARE CAPITAL

(millions)	**June 30, 2006** Number	Amount	December 31, 2005 Number	Amount
Common Shares Outstanding, Beginning of Year	**854.9**	**$ 5,131**	900.6	$ 5,299
Common Shares Issued under Option Plans	**4.6**	**101**	15.0	294
Common Shares Repurchased	**(43.7)**	**(373)**	(60.7)	(462)
Common Shares Outstanding, End of Period	**815.8**	**$ 4,859**	854.9	$ 5,131

Information related to common shares and stock options has been restated to reflect the effect of the common share split approved in April 2005.

Normal Course Issuer Bid

To June 30, 2006, the Company purchased 43.7 million Common Shares for total consideration of approximately $2,073 million. Of the amount paid, $373 million was charged to Share capital and $1,700 million was charged to Retained earnings.

EnCana has obtained regulatory approval each year under Canadian securities laws to purchase Common Shares under four consecutive Normal Course Issuer Bids ("Bids") which commenced in October 2002 and may continue until October 30, 2006. EnCana is entitled to purchase, for cancellation, up to approximately 85.6 million Common Shares under the renewed Bid which commenced on October 31, 2005 and will terminate no later than October 30, 2006.

Stock Options

The Company 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 grant date. Options granted under predecessor and/or related company replacement plans expire up to ten 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 ("TSAR's") attached to them at June 30, 2006. Information related to TSAR's is included in Note 12.

	Stock Options *(millions)*	**Weighted Average Exercise Price** *(C$)*
Outstanding, Beginning of Year	**20.7**	**23.36**
Exercised	**(4.6)**	**23.64**
Forfeited	**(0.3)**	**23.81**
Outstanding, End of Period	**15.8**	**23.27**
Exercisable, End of Period	**15.4**	**23.24**

	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 22.99	1.4	2.0	15.22	1.4	15.05
23.00 to 23.49	0.3	1.6	23.23	0.2	23.25
23.50 to 23.99	5.9	1.8	23.89	5.8	23.89
24.00 to 24.49	7.7	0.9	24.17	7.7	24.17
24.50 to 25.99	0.5	2.2	25.23	0.3	25.23
	15.8	1.4	23.27	15.4	23.24

At June 30, 2006 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)

12. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at June 30, 2006. Additional information is contained in Note 15 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2005.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
Current Service Cost	**$ 4**	$ 2	**$ 7**	$ 4
Interest Cost	**4**	3	**8**	6
Expected Return on Plan Assets	**(4)**	(3)	**(8)**	(6)
Expected Actuarial Loss on Accrued Benefit Obligation	**2**	-	**3**	1
Expected Amortization of Past Service Costs	**-**	-	**1**	1
Amortization of Transitional Obligation	**(1)**	1	**(1)**	-
Expense for Defined Contribution Plan	**6**	5	**11**	10
Net Benefit Plan Expense	**$ 11**	$ 8	**$ 21**	$ 16

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

B) Share Appreciation Rights ("SAR's")

The following table summarizes the information about SAR's at June 30, 2006:

	Outstanding SAR's	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**246,739**	**23.13**
Exercised	**(242,739)**	**23.18**
Outstanding, End of Period	**4,000**	**20.25**
Exercisable, End of Period	**4,000**	**20.25**
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**319,511**	**14.33**
Exercised	**(253,875)**	**14.94**
Outstanding, End of Period	**65,636**	**11.96**
Exercisable, End of Period	**65,636**	**11.96**

For the period ended June 30, 2006, EnCana has not recorded any compensation costs related to the outstanding SAR's (2005 - $10 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. COMPENSATION PLANS (continued)

C) Tandem Share Appreciation Rights ("TSAR's")

The following table summarizes the information about Tandem SAR's at June 30, 2006:

	Outstanding TSAR's	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**8,403,967**	**38.41**
Granted	**10,676,500**	**48.63**
Exercised - SAR's	**(344,212)**	**35.01**
Exercised - Options	**(16,044)**	**32.47**
Forfeited	**(471,892)**	**40.81**
Outstanding, End of Period	**18,248,319**	**44.40**
Exercisable, End of Period	**2,067,199**	**36.33**

For the period ended June 30, 2006, EnCana recorded compensation costs of $58 million related to the outstanding TSAR's (2005 - $31 million).

D) Deferred Share Units ("DSU's")

The following table summarizes the information about DSU's at June 30, 2006:

	Outstanding DSU's	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**836,561**	**26.81**
Granted, Directors	**70,000**	**56.71**
Exercised	**(52,562)**	**27.92**
Units, in Lieu of Dividends	**5,748**	**56.85**
Outstanding, End of Period	**859,747**	**29.38**
Exercisable, End of Period	**859,747**	**29.38**

For the period ended June 30, 2006, EnCana recorded compensation costs of $8 million related to the outstanding DSU's (2005 - $13 million).

E) Performance Share Units ("PSU's")

The following table summarizes the information about PSU's at June 30, 2006:

	Outstanding PSU's	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**4,704,348**	**30.65**
Granted	**18,540**	**29.66**
Exercised	**(239,794)**	**23.26**
Forfeited	**(200,818)**	**30.45**
Outstanding, End of Period	**4,282,276**	**31.08**
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**739,649**	**25.22**
Granted	**2,367**	**25.53**
Forfeited	**(80,876)**	**22.50**
Outstanding, End of Period	**661,140**	**25.56**

For the period ended June 30, 2006, EnCana recorded a reduction to compensation costs of $1 million related to the outstanding PSU's (2005 - $33 million).

At June 30, 2006, EnCana has approximately 5.5 million Common Shares held in trust for issuance upon vesting of the PSU's.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. PER SHARE AMOUNTS

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

	Three Months Ended			Six Months Ended	
	March 31,	June 30,		June 30,	
(millions)	2006	**2006**	2005	**2006**	2005
Weighted Average Common Shares Outstanding - Basic	847.9	**829.6**	872.0	**838.7**	881.8
Effect of Dilutive Securities	16.9	**15.5**	19.9	**16.7**	18.9
Weighted Average Common Shares Outstanding - Diluted	864.8	**845.1**	891.9	**855.4**	900.7

14. 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 (Loss) Gain on Risk Management Activities

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

	Realized Gain (Loss)			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 160**	$ (114)	**$ (46)**	$ (133)
Operating Expenses and Other	**2**	5	**3**	10
Gain (Loss) on Risk Management - Continuing Operations	**162**	(109)	**(43)**	(123)
Gain (Loss) on Risk Management - Discontinued Operations	**3**	(32)	**4**	(56)
	$ 165	$ (141)	**$ (39)**	$ (179)

	Unrealized Gain (Loss)			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 230**	$ 315	**$ 1,493**	$ (647)
Operating Expenses and Other	**-**	(1)	**(2)**	2
Gain (Loss) on Risk Management - Continuing Operations	**230**	314	**1,491**	(645)
Gain (Loss) on Risk Management - Discontinued Operations	**(1)**	31	**22**	1
	$ 229	$ 345	**$ 1,513**	$ (644)

Amounts Recognized on Transition

Upon initial adoption of the current accounting policy for risk management instruments on January 1, 2004, the fair value of all outstanding financial instruments that were not considered accounting hedges was recorded in the Consolidated Balance Sheet with an offsetting net deferred loss amount (the "transition amount"). The transition amount is recognized into net earnings over the life of the related contracts. Changes in fair value after that time are recorded in the Consolidated Balance Sheet with an associated unrealized gain or loss recorded in net earnings.

At June 30, 2006, a net unrealized gain remains to be recognized over the next three years as follows:

	Unrealized Gain
2006	
Three months ended September 30, 2006	$ 7
Three months ended December 31, 2006	6
Total remaining to be recognized in 2006	$ 13
2007	$ 15
2008	1
Total to be recognized	$ 29

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2006 to June 30, 2006:

	Transition Amount	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	$ (40)	$ (640)	$ -
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During 2006	-	1,463	1,463
Fair Value of Contracts in Place at Transition Expired During 2006	11	-	11
Fair Value of Contracts Realized During 2006	-	39	39
Fair Value of Contracts Outstanding	$ (29)	$ 862	$ 1,513
Unamortized Premiums Paid on Options		230	
Fair Value of Contracts and Premiums Paid, End of Period		$ 1,092	
Amounts Allocated to Continuing Operations	$ (29)	$ 1,090	$ 1,491
Amounts Allocated to Discontinued Operations	-	2	22
	$ (29)	$ 1,092	$ 1,513

At June 30, 2006, the remaining net deferred amounts recognized on transition and the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

	As at June 30, 2006
Remaining Deferred Amounts Recognized on Transition	
Accounts receivable and accrued revenues	**$ 1**
Accounts payable and accrued liabilities	**22**
Other liabilities	**8**
Net Deferred Gain - Continuing Operations	**$ 29**
Risk Management	
Current asset	**$ 965**
Long-term asset	**313**
Current liability	**170**
Long-term liability	**18**
Net Risk Management Asset - Continuing Operations	**1,090**
Net Risk Management Asset - Discontinued Operations	**2**
	$ 1,092

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

	As at June 30, 2006
Commodity Price Risk	
Natural gas	**$ 1,153**
Crude oil	**(68)**
Credit Derivatives	**(1)**
Interest Rate Risk	**6**
Total Fair Value Positions - Continuing Operations	**1,090**
Total Fair Value Positions - Discontinued Operations	**2**
	$ 1,092

Information with respect to credit derivatives and interest rate risk contracts in place at December 31, 2005 is disclosed in Note 16 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at June 30, 2006.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Natural Gas

At June 30, 2006, the Company's gas risk management activities from financial contracts had an unrealized gain of $985 million and a fair market value position of $1,155 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	515	2006	5.65	US$/Mcf	$ (133)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	(23)
Houston Ship Channel (HSC)	90	2006	5.08	US$/Mcf	(22)
Other	91	2006	5.07	US$/Mcf	(16)
NYMEX Fixed Price	260	2007	7.86	US$/Mcf	(117)
Other	8	2007	8.97	US$/Mcf	-
Options					
Purchased NYMEX Put Options	2,693	2006	7.77	US$/Mcf	530
Purchased NYMEX Put Options	240	2007	6.00	US$/Mcf	3
Basis Contracts					
Fixed NYMEX to AECO Basis	789	2006	(0.69)	US$/Mcf	71
Fixed NYMEX to Rockies Basis	322	2006	(0.60)	US$/Mcf	46
Fixed NYMEX to CIG Basis	297	2006	(0.83)	US$/Mcf	31
Other	170	2006	(0.34)	US$/Mcf	12
Fixed NYMEX to AECO Basis	747	2007	(0.72)	US$/Mcf	166
Fixed NYMEX to Rockies Basis	538	2007	(0.65)	US$/Mcf	205
Fixed NYMEX to CIG Basis	390	2007	(0.76)	US$/Mcf	135
Fixed Rockies to CIG Basis	12	2007	(0.10)	US$/Mcf	-
Fixed NYMEX to AECO Basis	191	2008	(0.78)	US$/Mcf	22
Fixed NYMEX to Rockies Basis	162	2008	(0.59)	US$/Mcf	48
Fixed NYMEX to Rockies Basis (NYMEX Adjusted)	100	2008	17% of NYMEX	US$/Mcf	(1)
Fixed NYMEX to CIG Basis	40	2008-2009	(0.68)	US$/Mcf	20
Purchase Contracts					
Fixed Price Contracts					
Waha Purchase	23	2006	5.32	US$/Mcf	4
					981
Other Financial Positions *					4
Total Unrealized Gain on Financial Contracts					985
Unamortized Premiums Paid on Options					170
Total Fair Value Positions					$ 1,155
Total Fair Value Positions - Continuing Operations					$ 1,153
Total Fair Value Positions - Discontinued Operations					2
Total Fair Value Positions					$ 1,155

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Crude Oil

At June 30, 2006, the Company's oil risk management activities from financial contracts had an unrealized loss of $(128) million and a fair market value position of $(68) million. The contracts were as follows:

	Notional Volumes *(bbls/d)*	Term	Average Price	Fair Market Value
Fixed WTI NYMEX Price	15,000	2006	34.56 US$/bbl	$ (111)
Unwind WTI NYMEX Fixed Price	(1,300)	2006	52.75 US$/bbl	5
Purchased WTI NYMEX Put Options	59,000	2006	50.44 US$/bbl	(16)
Purchased WTI NYMEX Call Options	(13,700)	2006	61.24 US$/bbl	27
Purchased WTI NYMEX Put Options	43,000	2007	44.44 US$/bbl	(29)
				(124)
Other Financial Positions *				(4)
Total Unrealized Loss on Financial Contracts				(128)
Unamortized Premiums Paid on Options				60
Total Fair Value Positions				$ (68)
Total Fair Value Positions - Continuing Operations				$ (68)

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

15. CONTINGENCIES

Legal Proceedings

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

Discontinued Merchant Energy Operations

California

As disclosed previously, in July 2003, the Company’s indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (“WD”), concluded a settlement with the U.S. Commodity Futures Trading Commission (“CFTC”) of a previously disclosed CFTC investigation whereby WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC’s order.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws.

In the Gallo action, the decision dealing with the issue of whether the scope of the Federal Energy Regulatory Commission’s exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims is on appeal to the United States Court of Appeals for the Ninth Circuit. The Gallo lawsuit is stayed pending this appeal.

Without admitting any liability in the lawsuits, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court subject to final documentation and approval by the San Diego Superior Court. The individual parties who had brought their own actions are not parties to this settlement. WD has also agreed to pay $2.4 million to settle the class action lawsuits filed in the United States District Court in California, without admitting any liability in the lawsuits, subject to final documentation and approval by the United States District Court.

New York

WD was a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants’ alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD agreed to pay $8.2 million to settle the New York class action lawsuit. Final documentation and approval by the New York District Court have been obtained and WD has paid the stated settlement amount.

Based on the aforementioned settlements, a total of $31 million has been accrued. EnCana Corporation and WD intend to vigorously defend against the remaining 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.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2006 Year-to-date	2006 Q2	2006 Q1	2005 Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1
TOTAL CONSOLIDATED								
Cash Flow	**3,506**	**1,815**	1,691	7,426	2,510	1,931	1,572	1,413
Per share - Basic	**4.18**	**2.19**	1.99	8.55	2.94	2.26	1.80	1.58
- Diluted	**4.10**	**2.15**	1.96	8.35	2.88	2.20	1.76	1.55
Net Earnings (Loss)	**3,631**	**2,157**	1,474	3,426	2,366	266	839	(45)
Per share - Basic	**4.33**	**2.60**	1.74	3.95	2.77	0.31	0.96	(0.05)
- Diluted	**4.24**	**2.55**	1.70	3.85	2.71	0.30	0.94	(0.05)
Operating Earnings (1)	**1,518**	**824**	694	3,241	1,271	704	655	611
Per share - Diluted	**1.77**	**0.98**	0.80	3.64	1.46	0.80	0.73	0.67
CONTINUING OPERATIONS								
Cash Flow from Continuing Operations	**3,418**	**1,839**	1,579	6,962	2,390	1,823	1,502	1,247
Net Earnings (Loss) from Continuing Operations	**3,065**	**1,593**	1,472	2,829	1,869	348	774	(162)
Per share - Basic	**3.65**	**1.92**	1.74	3.26	2.19	0.41	0.89	(0.18)
- Diluted	**3.58**	**1.88**	1.70	3.18	2.14	0.40	0.87	(0.18)
Operating Earnings - Continuing Operations (2)	**1,501**	**841**	660	3,048	1,229	733	611	475
Effective Tax Rates using								
Net Earnings	**23.0%**			30.8%				
Operating Earnings, excluding dispositions	**35.6%**			33.0%				
Canadian Statutory Rate	**34.8%**			37.9%				
Foreign Exchange Rates (US$ per C$1)								
Average	**0.879**	**0.892**	0.866	0.825	0.852	0.833	0.804	0.815
Period end	**0.897**	**0.897**	0.857	0.858	0.858	0.861	0.816	0.827

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

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

Common Share Information

	2006 Year-to-date	2006 Q2	2006 Q1	2005 Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1
Common Shares Outstanding *(millions)*								
Period end	**815.8**	**815.8**	836.2	854.9	854.9	853.8	860.2	881.7
Average - Basic	**838.7**	**829.6**	847.9	868.3	854.4	855.1	872.0	891.8
Average - Diluted	**855.4**	**845.1**	864.8	889.2	872.5	875.8	891.9	909.0
Price Range *($ per share)*								
TSX - C$								
High	**59.38**	**59.38**	57.10	69.64	69.64	68.70	51.27	44.28
Low	**44.96**	**49.51**	44.96	32.55	50.04	47.72	39.05	32.55
Close	**58.78**	**58.78**	54.50	52.56	52.56	67.85	48.33	42.72
NYSE - US$								
High	**53.31**	**53.31**	50.50	59.82	59.82	58.49	41.56	36.45
Low	**39.54**	**44.02**	39.54	26.45	42.00	39.26	31.31	26.45
Close	**52.64**	**52.64**	46.73	45.16	45.16	58.31	39.59	35.21
Share Volume Traded *(millions)*	**920.4**	**392.0**	528.4	1,619.6	552.8	388.9	327.3	350.6
Share Value Traded *(US$ millions weekly average)*	**1,670.1**	**1,484.8**	1,850.5	1,289.1	2,050.1	1,400.4	878.8	852.6

Financial Metrics

	2006	2005
Net Debt to Capitalization	**26%**	33%
Net Debt to Adjusted EBITDA	**0.6x**	1.1x
Return on Capital Employed	**29%**	17%
Return on Common Equity	**40%**	23%

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics ***(continued)***

Net Capital Investment *($ millions)*	**2006**	2005
Upstream		
Canada	**$ 2,302**	$ 1,871
United States	**1,170**	878
Other Countries	**39**	29
	3,511	2,778
Market Optimization	**38**	115
Corporate	**29**	15
Core Capital from Continuing Operations	**3,578**	2,908
Upstream		
Acquisitions		
Property		
Canada	**29**	23
United States [1]	**257**	15
Dispositions		
Property		
Canada	**(13)**	(402)
United States	**-**	(2,055)
Market Optimization		
Corporate [2]	**(244)**	-
Corporate	**-**	(2)
Net Acquisition and Disposition activity from Continuing Operations	**29**	(2,421)
Discontinued Operations		
Ecuador [3]	**(1,116)**	100
Midstream [4]	**(1,299)**	25
Net Capital Investment	**$ 1,192**	$ 612

(1) Acquired additional operated interest in East Texas which closed June 29, 2006.

(2) Sale of shares of Entrega Gas Pipeline LLC

(3) Sale of Ecuador interests closed February 28, 2006

(4) Sale of majority of Gas Storage interests closed May 12, 2006

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties

Sales Volumes	**2006**			2005				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS								
Produced Gas *(MMcf/d)*								
Canada								
Production	**2,187**	**2,192**	2,182	2,125	2,172	2,123	2,151	2,052
Inventory withdrawal	**-**	**-**	-	7	-	-	-	27
Canada Sales	**2,187**	**2,192**	2,182	2,132	2,172	2,123	2,151	2,079
United States	**1,165**	**1,169**	1,161	1,095	1,154	1,099	1,061	1,067
Total Produced Gas	**3,352**	**3,361**	3,343	3,227	3,326	3,222	3,212	3,146
Oil and Natural Gas Liquids *(bbls/d)*								
North America								
Light and Medium Oil	**44,802**	**43,727**	45,889	47,328	45,792	43,313	50,020	50,280
Heavy Oil	**88,893**	**85,343**	92,481	83,090	88,386	81,089	82,274	80,546
Natural Gas Liquids [(1)]								
Canada	**11,805**	**11,607**	12,006	11,907	12,287	11,924	11,719	11,692
United States	**12,605**	**12,793**	12,415	13,675	12,824	14,131	13,095	14,666
Total Oil and Natural Gas Liquids	**158,105**	**153,470**	162,791	156,000	159,289	150,457	157,108	157,184
Total Continuing Operations *(MMcfe/d)*	**4,300**	**4,282**	4,320	4,163	4,282	4,125	4,155	4,089
DISCONTINUED OPERATIONS								
Ecuador								
Production	**24,191**	**-**	48,650	72,916	70,480	71,896	73,662	75,695
Over/(under) lifting	**746**	**-**	1,500	(1,851)	(537)	(3,186)	(486)	(3,208)
Ecuador Sales *(bbls/d)*	**24,937**	**-**	50,150	71,065	69,943	68,710	73,176	72,487
Total Discontinued Operations *(MMcfe/d)*	**150**	**-**	301	426	419	412	439	435
Total *(MMcfe/d)*	**4,450**	**4,282**	4,621	4,589	4,701	4,537	4,594	4,524

(1) Natural gas liquids include condensate volumes.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2006			2005				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS								
Produced Gas - Canada *($/Mcf)*								
Price	**6.68**	**5.71**	7.66	7.27	10.00	7.18	6.08	5.70
Production and mineral taxes	**0.13**	**0.08**	0.18	0.10	0.10	0.10	0.10	0.09
Transportation and selling	**0.35**	**0.35**	0.34	0.36	0.36	0.36	0.36	0.37
Operating	**0.78**	**0.77**	0.79	0.67	0.72	0.68	0.62	0.65
Netback	**5.42**	**4.51**	6.35	6.14	8.82	6.04	5.00	4.59
Produced Gas - United States *($/Mcf)*								
Price	**6.88**	**6.08**	7.70	7.82	10.84	7.51	6.60	6.04
Production and mineral taxes	**0.53**	**0.22**	0.85	0.81	1.19	0.75	0.65	0.62
Transportation and selling	**0.50**	**0.50**	0.49	0.46	0.45	0.49	0.42	0.46
Operating	**0.67**	**0.70**	0.64	0.53	0.60	0.55	0.50	0.45
Netback	**5.18**	**4.66**	5.72	6.02	8.60	5.72	5.03	4.51
Produced Gas - Total North America *($/Mcf)*								
Price	**6.75**	**5.84**	7.68	7.46	10.29	7.29	6.25	5.81
Production and mineral taxes	**0.27**	**0.13**	0.41	0.34	0.48	0.32	0.28	0.27
Transportation and selling	**0.40**	**0.40**	0.40	0.40	0.39	0.41	0.38	0.40
Operating	**0.74**	**0.74**	0.74	0.62	0.68	0.64	0.58	0.58
Netback	**5.34**	**4.57**	6.13	6.10	8.74	5.92	5.01	4.56
Natural Gas Liquids - Canada *($/bbl)*								
Price	**51.98**	**55.19**	48.84	44.24	49.51	47.39	39.55	40.04
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**0.67**	**0.73**	0.61	0.42	0.46	0.48	0.39	0.35
Netback	**51.31**	**54.46**	48.23	43.82	49.05	46.91	39.16	39.69
Natural Gas Liquids - United States *($/bbl)*								
Price	**56.20**	**58.25**	54.07	48.36	54.14	53.92	44.79	40.93
Production and mineral taxes	**3.86**	**2.60**	5.18	4.86	5.42	5.46	4.37	4.20
Transportation and selling	**0.01**	**0.01**	0.01	0.01	0.01	0.01	0.01	0.01
Netback	**52.33**	**55.64**	48.88	43.49	48.71	48.45	40.41	36.72
Natural Gas Liquids - Total North America *($/bbl)*								
Price	**54.16**	**56.80**	51.50	46.44	51.87	50.93	42.32	40.53
Production and mineral taxes	**1.99**	**1.36**	2.63	2.60	2.77	2.96	2.31	2.34
Transportation and selling	**0.33**	**0.35**	0.31	0.20	0.23	0.23	0.19	0.16
Netback	**51.84**	**55.09**	48.56	43.64	48.87	47.74	39.82	38.03
Crude Oil - Light and Medium - North America *($/bbl)*								
Price	**53.31**	**61.62**	45.31	45.09	46.27	55.41	41.44	38.57
Production and mineral taxes	**2.19**	**2.47**	1.92	1.54	1.83	1.29	1.71	1.32
Transportation and selling	**0.98**	**0.65**	1.29	1.20	1.14	1.29	1.20	1.19
Operating	**7.72**	**7.36**	8.06	6.34	6.41	6.24	6.34	6.38
Netback	**42.42**	**51.14**	34.04	36.01	36.89	46.59	32.19	29.68
Crude Oil - Heavy - North America *($/bbl)*								
Price	**34.62**	**46.49**	23.53	27.92	28.27	39.69	22.77	20.76
Production and mineral taxes	**0.05**	**0.07**	0.04	0.04	0.05	0.04	0.02	0.03
Transportation and selling	**1.59**	**2.00**	1.21	1.20	1.11	1.08	1.13	1.52
Operating	**7.27**	**7.90**	6.68	6.50	6.96	6.57	6.57	5.83
Netback	**25.71**	**36.52**	15.60	20.18	20.15	32.00	15.05	13.38
Crude Oil - Total North America *($/bbl)*								
Price	**40.88**	**51.62**	30.76	34.15	34.41	45.16	29.83	27.60
Production and mineral taxes	**0.77**	**0.88**	0.66	0.58	0.66	0.48	0.66	0.53
Transportation and selling	**1.39**	**1.54**	1.24	1.20	1.12	1.15	1.15	1.39
Operating	**7.42**	**7.72**	7.13	6.44	6.77	6.45	6.48	6.04
Netback	**31.30**	**41.48**	21.73	25.93	25.86	37.08	21.54	19.64

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2006			2005				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS (continued)								
Total Liquids - Canada *($/bbl)*								
Price	**41.75**	**51.91**	32.17	34.97	35.65	45.35	30.58	28.60
Production and mineral taxes	**0.70**	**0.80**	0.61	0.53	0.60	0.43	0.61	0.48
Transportation and selling	**1.33**	**1.48**	1.19	1.14	1.07	1.09	1.09	1.31
Operating	**6.80**	**7.07**	6.55	5.89	6.19	5.83	5.96	5.55
Netback	**32.92**	**42.56**	23.82	27.41	27.79	38.00	22.92	21.26
Total Liquids - Total North America *($/bbl)*								
Price	**42.93**	**52.44**	33.87	36.17	37.16	46.16	31.80	29.77
Production and mineral taxes	**0.96**	**0.96**	0.96	0.91	0.99	0.91	0.92	0.83
Transportation and selling	**1.22**	**1.35**	1.10	1.04	0.98	0.99	1.00	1.18
Operating	**6.27**	**6.49**	6.06	5.38	5.70	5.33	5.46	5.03
Netback	**34.48**	**43.64**	25.75	28.84	29.49	38.93	24.42	22.73
Total North America *($/Mcfe)*								
Price	**6.84**	**6.46**	7.22	7.13	9.37	7.38	6.03	5.62
Production and mineral taxes	**0.24**	**0.13**	0.36	0.30	0.41	0.29	0.25	0.24
Transportation and selling	**0.36**	**0.36**	0.35	0.35	0.34	0.35	0.33	0.36
Operating [(1)]	**0.81**	**0.82**	0.80	0.68	0.74	0.69	0.66	0.64
Netback	**5.43**	**5.15**	5.71	5.80	7.88	6.05	4.79	4.38

[(1)] Year-to-date operating costs include costs related to long-term incentives of $0.02/Mcfe. (Year-to-date 2005 - $0.02/Mcfe)

Impact of Upstream Realized Financial Hedging

Natural Gas *($/Mcf)*	**0.07**	**0.66**	(0.53)	(0.32)	(0.88)	(0.39)	(0.14)	0.18
Liquids *($/bbl)*	**(3.27)**	**(3.43)**	(3.12)	(5.18)	(5.00)	(5.70)	(4.88)	(5.18)
Total *($/Mcfe)*	**(0.06)**	**0.40**	(0.53)	(0.44)	(0.87)	(0.52)	(0.30)	(0.06)

Average Royalty Rates
(excluding impact of realized financial hedging)

Produced Gas								
Canada	**10.8%**	**10.4%**	11.2%	11.7%	11.9%	11.8%	11.0%	11.9%
United States	**18.7%**	**18.7%**	18.7%	18.6%	18.6%	19.9%	17.9%	18.1%
Crude Oil								
Canada and United States	**8.9%**	**10.5%**	7.5%	8.8%	8.8%	8.7%	9.2%	8.7%
Natural Gas Liquids								
Canada	**15.3%**	**14.4%**	16.1%	14.9%	14.4%	15.8%	15.6%	13.8%
United States	**19.3%**	**20.1%**	18.3%	18.2%	19.4%	20.1%	12.7%	20.0%
Total North America	**13.0%**	**13.1%**	12.9%	13.3%	13.5%	13.8%	12.6%	13.3%

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

Per-unit Results

(excluding impact of realized financial hedging)

	2006			2005				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
DISCONTINUED OPERATIONS								
Crude Oil - Ecuador *($/bbl)*								
Price	**44.35**	**-**	44.35	39.36	37.82	47.76	36.37	35.80
Production and mineral taxes	**5.03**	**-**	5.03	5.04	4.63	7.66	4.53	3.42
Transportation and selling	**2.25**	**-**	2.25	2.25	1.86	2.45	2.48	2.21
Operating	**5.55**	**-**	5.55	5.32	5.82	6.05	5.18	4.26
Netback	**31.52**	**-**	31.52	26.75	25.51	31.60	24.18	25.91

Impact of Upstream Realized Financial Hedging - Crude Oil

Ecuador *($/bbl)*	**(0.12)**	**-**	(0.12)	(4.92)	(3.57)	(7.81)	(4.90)	(3.48)

Average Royalty Rates

(excluding impact of realized financial hedging)

Crude Oil								
Ecuador	**25.2%**	**-**	25.2%	27.2%	29.4%	26.3%	26.3%	26.9%

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EnCana Corporation

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