Q3 2009

ENCANA
energy for people

EnCana generates third quarter cash flow of US$2.1 billion, or $2.77 per share – down 26 percent

EnCana and Cenovus Energy release 2010 preliminary budgets

Calgary, Alberta, (November 12, 2009) – EnCana Corporation (TSX & NYSE: ECA) continued to deliver strong operating and financial results in the third quarter of 2009, despite low natural gas prices. EnCana generated third quarter cash flow of US$2.1 billion, or $2.77 per share, and operating earnings of $775 million, or $1.03 per share – down 26 and 46 percent respectively compared to the third quarter of 2008. EnCana's financial performance was significantly enhanced by commodity price hedges, which contributed $913 million in realized after-tax gains, or $1.22 per share, to cash flow in the third quarter.

Shut-in and curtailed gas coming back on this winter
To help preserve shareholder value on the expectation that natural gas prices would rise to more economic levels, EnCana curtailed or shut in about 500 million cubic feet per day (MMcf/d) of natural gas production in the third quarter. These shut-in and curtailed volumes are expected to be brought back on stream during the winter of 2009/10. Total third quarter production was about 4.4 billion cubic feet equivalent per day (Bcfe/d), down 7 percent compared to one year earlier. While natural gas production was down about 9 percent to 3.6 billion cubic feet per day (Bcf/d), oil and natural gas liquids (NGLs) production increased about 4 percent to 139,000 barrels per day (bbls/d), led by a 44 percent production increase from the Foster Creek enhanced oil project. Natural gas production in the first nine months of 2009 was 3.7 Bcf/d, which is higher than the company's 2009 guidance of 3.6 Bcf/d. This reflects EnCana's operational success even during a period when it chose to curtail production due to low prices.

"Our company's solid operational and financial performance during a period of weak prices is evidence that EnCana's strategy is working. We remain focused on being the lowest cost producer by applying advanced technologies and by pursuing operational efficiencies across all resource plays. In addition, our successful hedging program has helped us sustain strong cash flow. To help preserve the value of our resource base, we have curtailed significant natural gas production in many of our operating areas and have significant productive capacity available to bring to market as prices recover," said Randy Eresman, EnCana's President & Chief Executive Officer.

IMPORTANT NOTE: EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report gas and oil production, sales and reserves on an after-royalties basis. The company's financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Per share amounts for cash flow and earnings are on a diluted basis.

EnCana Third Quarter 2009 Highlights
(all year-over-year comparisons are to the third quarter of 2008)

Financial
- Cash flow was $2.1 billion or $2.77 per share, a decrease of 26 percent
- Operating earnings were $775 million or $1.03 per share, down 46 percent
- Net earnings were $25 million or 3 cents per share
- Capital investment, excluding acquisitions and divestitures, was $1.3 billion, down 16 percent, primarily due to lower drilling and completion expenditures as a result of fewer wells drilled and cost deflation
- Free cash flow was $741 million, down 39 percent (Free cash flow is defined in Note 1 on page 9)
- Realized natural gas prices were $7.31 per thousand cubic feet (Mcf), down 8 percent, and realized liquids prices were $57.39 per barrel (bbl), down 37 percent. These prices include financial hedges

- At the end of the quarter, debt to capitalization was 25 percent and debt to adjusted EBITDA was 1.1 times. These ratios do not include the $3.5 billion of debt securities intended for use by Cenovus, the proceeds of which have been placed in escrow pending the completion of the split transaction
- Paid a dividend of 40 cents per share
- EnCana's integrated oil business venture with ConocoPhillips generated $266 million in operating cash flow, including $180 million from the Foster Creek and Christina Lake upstream projects, and $86 million from the downstream business

Operating – Upstream
- Total natural gas production was 3.6 Bcf/d, down 9 percent, primarily due to a decision to shut in or curtail about 500 MMcf/d of production because of the low price environment and natural declines in conventional properties. This reduced production was partially offset by lower royalty volumes in Alberta due to price sensitive royalty rates
- Total oil and NGLs production was more than 139,000 bbls/d, an increase of 4 percent
- Foster Creek and Christina Lake oil production grew 43 percent to approximately 45,000 bbls/d net to EnCana
- Operating and administrative costs were $1.26 per thousand cubic feet equivalent (Mcfe), which is up from 79 cents per Mcfe in the third quarter of 2008, a period when there was a large recovery of long-term incentive costs as a result of a significant decline in the EnCana share price. These higher 2009 costs were offset primarily by a weaker Canadian dollar and lower purchased fuel and workover costs

Operating – Downstream
- Refined products averaged 451,000 bbls/d (225,500 bbls/d net to EnCana), up 3 percent
- Refinery crude utilization was 94 percent or 425,000 bbls/d crude throughput (212,500 bbls/d net to EnCana), up 3 percent
- The Wood River coker and refinery expansion (CORE) project was approximately 62 percent complete at the end of September.

Financial Summary – Total Consolidated

(for the period ended September 30) ($ millions, except per share amounts)	**Q3 2009**	Q3 2008	% Δ	**9 months 2009**	9 months 2008	% Δ
Cash flow[1]	**2,079**	2,809	-26	**6,176**	8,087	-24
Per share diluted	**2.77**	3.74	-26	**8.22**	10.75	-24
Operating earnings[1]	**775**	1,442	-46	**2,640**	3,956	-33
Per share diluted	**1.03**	1.92	-46	**3.51**	5.26	-33
Net earnings	**25**	3,553		**1,226**	4,867	
Per share diluted	**0.03**	4.73		**1.63**	6.47	
Capital investment	**1,338**	1,588	-16	**3,924**	5,155	-24
Earnings Reconciliation Summary – Total Consolidated						
Net earnings	**25**	3,553		**1,226**	4,867	
Add back (losses) & deduct gains						
Unrealized mark-to-market accounting gain (loss), after-tax	**(931)**	2,043		**(1,592)**	1,071	
Non-operating foreign exchange gain (loss), after-tax	**181**	(31)		**178**	(259)	
Gain (loss) on discontinuance, after-tax	**-**	99		**-**	99	
Operating earnings[1]	**775**	1,442	-46	**2,640**	3,956	-33
Per share diluted	**1.03**	1.92	-46	**3.51**	5.26	-33

1 Cash flow and operating earnings are non-GAAP measures as defined in Note 1 on page 9.

Price risk management affects net earnings

Operating earnings include the realized hedging gains and losses which reflect the actual value of the hedging contracts when settled. Management believes operating earnings are a better measure of performance because they remove the variability associated with unrealized mark-to-market accounting accruals. Net earnings include both realized hedging gains/losses and unrealized mark-to-market accounting gains/losses.

Net earnings in the third quarter of 2009 were affected by the combined impact of realized and unrealized hedging gains/losses which resulted in an $18 million after-tax decrease to net earnings in 2009 compared to a $1.8 billion after-tax increase to net earnings in the third quarter of 2008.

Production & Drilling Summary						
Total Consolidated						
(for the period ended September 30) (After royalties)	**Q3 2009**	Q3 2008	% Δ	**9 months 2009**	9 months 2008	% Δ
Natural Gas (MMcf/d)	**3,551**	3,917	-9	**3,735**	3,830	-2
Oil and NGLs (Mbbls/d)	**139**	134	4	**136**	133	2
Total Production (MMcfe/d)	**4,387**	4,718	-7	**4,554**	4,627	-2
Total net wells drilled	**292**	730	-60	**1,391**	2,282	-39

Key resource play production
Third quarter oil and natural gas production from key resource plays decreased 7 percent to 3.4 Bcfe/d compared to 3.6 Bcfe/d in the third quarter of 2008. Key resource play oil production was up 20 percent from the third quarter of 2008 to about 81,000 bbls/d led by Foster Creek and Christina Lake. Natural gas key resource play production was down by 10 percent, to 2.9 Bcf/d, due to a decision to shut in some wells, restrict productive capacity and delay some well completions or tie-ins to sales pipelines because of lower natural gas prices. These company-wide initiatives resulted in production restrictions of about 500 MMcf/d in the quarter.

Horn River and Haynesville shale plays continue to deliver strong drilling results
Results from drilling and completion work at EnCana's Horn River play in northeast British Columbia continue to build the company's confidence in the long term potential of this emerging shale gas play, where 47 gross wells have been drilled to date (23.5 net to EnCana). Performance from the first 13 gross wells completed by EnCana and its partner are very positive. Initial 30-day production rates have been between 8 million and 10 million cubic feet of gas per day. At the Haynesville play in northern Louisiana and East Texas, EnCana drilled 12 net wells and production during the quarter averaged about 80 MMcf/d. Well costs have dropped about 40 percent with EnCana's three best wells averaging below $8 million per well.

Integrated oil business production increases
EnCana's integrated oil business with ConocoPhillips achieved a successful third quarter generating operating cash flow of $266 million. Production at Foster Creek and Christina Lake was up 43 percent. Despite the strong production growth, upstream operating cash flow was down 2 percent to $180 million due to a 37 percent decrease in crude oil prices. The Borger and Wood River refineries generated operating cash flow of $86 million compared to a loss of $96 million in the third quarter of 2008. Higher capacity utilization and lower purchased-product and operating costs contributed to the improvement.

Expansion of oil production capacity at Foster Creek and Christina Lake on track
At Foster Creek, oil production from the phase D and E expansions continues to ramp up and the operation is on target to exit 2009 producing between 90,000 and 100,000 bbls/d (45,000 to 50,000 bbls/d net to EnCana). At Christina Lake, construction of phase C continues and current production is about 15,000 bbls/d (7,500 bbls/d net to EnCana).

Production from key North American resource plays

Resource Play (After royalties)	Daily Production									
	2009				2008					2007
	YTD	**Q3**	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas (MMcf/d)										
Jonah	**573**	**521**	576	623	603	573	615	630	595	557
Piceance	**358**	**334**	355	386	385	377	407	383	372	348
East Texas	**339**	**305**	304	409	334	408	339	316	273	143
Fort Worth	**141**	**135**	138	149	142	143	148	137	140	124
Greater Sierra	**206**	**189**	216	215	220	228	228	219	205	211
Cutbank Ridge	**328**	**322**	340	323	296	311	322	280	271	258
Bighorn	**165**	**154**	186	156	167	165	185	170	146	126
CBM	**319**	**318**	330	309	304	308	309	303	298	259
Shallow Gas	**661**	**649**	661	673	700	683	691	712	715	726
Total natural gas (MMcf/d)	**3,090**	**2,927**	3,106	3,243	3,151	3,196	3,244	3,150	3,015	2,752
Oil (Mbbls/d)										
Foster Creek	**34**	**39**	34	28	26	29	27	21	27	24
Christina Lake	**6**	**6**	6	7	4	6	5	4	2	3
Pelican Lake	**20**	**21**	19	21	22	20	22	21	24	23
Weyburn	**15**	**15**	15	16	14	15	14	13	14	15
Total oil (Mbbls/d)[1]	**76**	**81**	75	72	66	71	67	59	67	65
Total (MMcfe/d)[1]	**3,546**	**3,410**	3,557	3,676	3,548	3,621	3,648	3,506	3,417	3,141
% change from prior period	**+0.7**	**-4.1**	-3.2	+1.5	+13.0	-0.7	+4.1	+2.6	+2.7	+12.9

1 Totals may not add due to rounding.

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled									
	2009				2008					2007
	YTD	**Q3**	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas										
Jonah	**85**	**20**	30	35	175	40	43	49	43	135
Piceance	**113**	**25**	35	53	328	70	94	81	83	286
East Texas	**30**	**4**	11	15	78	23	22	22	11	35
Fort Worth	**23**	**1**	6	16	83	21	21	20	21	75
Greater Sierra	**42**	**17**	10	15	106	14	29	27	36	109
Cutbank Ridge	**56**	**18**	18	20	82	17	17	24	24	93
Bighorn	**52**	**17**	14	21	64	5	11	18	30	62
CBM	**316**	**37**	1	278	698	359	78	10	251	1,079
Shallow Gas	**436**	**55**	45	336	1,195	383	233	83	496	1,914
Total gas wells	**1,153**	**194**	170	789	2,809	932	548	334	995	3,788
Oil										
Foster Creek	**18**	**2**	10	6	20	1	6	1	12	23
Christina Lake	**-**	**-**	-	-	-	-	-	-	-	3
Pelican Lake	**5**	**-**	1	4	-	-	-	-	-	-
Weyburn	**-**	**-**	-	-	21	3	4	5	9	37
Total oil wells	**23**	**2**	11	10	41	4	10	6	21	63
Total	**1,176**	**196**	181	799	2,850	936	558	340	1,016	3,851

Natural gas and oil prices						
	Q3 2009	Q3 2008	**% Δ**	**9 months 2009**	9 months 2008	**% Δ**
Natural gas ($/MMBtu)						
NYMEX	**3.39**	10.24	-67	**3.92**	9.73	-60
EnCana Realized Gas Price[1] ($/Mcf)	**7.31**	7.94	-8	**7.18**	8.17	-12
Oil and NGLs ($/bbl)						
WTI	**68.24**	118.22	-42	**57.32**	113.52	-50
Western Canadian Select (WCS)	**58.06**	100.22	-42	**48.47**	93.16	-48
Differential WTI/WCS	**10.18**	18.00	-43	**8.85**	20.36	-57
EnCana Realized Liquids Price[1]	**57.39**	90.88	-37	**47.64**	83.49	-43
Chicago 3-2-1 Crack Spread ($/bbl)	**8.48**	17.29	-51	**9.72**	12.86	-24

1 Realized prices include the impact of financial hedging.

Price risk management

Risk management positions at September 30, 2009 are presented in Note 17 to the unaudited Interim Consolidated Financial Statements. In the third quarter of 2009, EnCana's commodity price risk management measures resulted in realized gains of approximately $913 million after tax, including a $916 million after-tax gain on natural gas and basis hedges and a $3 million after-tax loss on other hedges.

As of September 30, EnCana had hedged about 2 Bcf/d, of expected natural gas production for the 2010 gas year, which runs from November 1, 2009 to October 31, 2010, at an average NYMEX equivalent price of $6.08 per Mcf. EnCana also had 27,000 bbls/d of expected 2010 oil production hedged at an average fixed price of WTI $76.89 per bbl. This price hedging strategy increases certainty in cash flow to help EnCana meet its anticipated capital requirements and projected dividends. EnCana continually assesses its hedging needs and the opportunities available prior to establishing its capital program for the upcoming year.

Corporate developments

Split transaction preparation proceeding

Planning is on track to split EnCana into two independent companies: a pure-play natural gas company, EnCana, and an integrated oil company, Cenovus Energy Inc. A shareholders' meeting to vote on the proposed transaction is set for November 25, 2009. Subject to the required shareholder and court approvals being obtained and the satisfaction of conditions, the company expects to complete the transaction on November 30, 2009.

The Arrangement Circular for the shareholders' meeting has been mailed and is available on SEDAR's website, www.sedar.com, on EDGAR's website, www.sec.gov/edgar.shtml and on EnCana's website, www.encana.com.

Fourth Quarter Dividends

EnCana intends that the initial combined dividends of EnCana and Cenovus for the fourth quarter of 2009, after the Arrangement becomes effective, will be equal to EnCana's current quarterly dividend of US$0.40 per share, to be equally apportioned between EnCana and Cenovus. It is anticipated that such dividends will be payable on December 31, 2009 to common shareholders of record, for each respective company, as of December 21, 2009. Following completion of the Arrangement, the declaration of dividends will be at the sole discretion of the EnCana Board and the Cenovus Board and no dividend policy has been adopted by either company.

EnCana completes more than $900 million of net divestitures to date in 2009

In August of 2009, EnCana completed the sale to Bonavista Energy Trust of approximately 409,000 net acres of non-core natural gas and oil producing properties for approximately $632 million. The transaction included property known as the Hoadley trend, which covers an expansive area in west-central Alberta. In early November, EnCana completed the sale of its Senlac heavy oil operation in west-central Saskatchewan, for about $83 million. In the first nine months of 2009, EnCana had net divestitures of approximately $902 million, which is in line with targeted 2009 divestitures of between $500 million and $1 billion.

EnCana 2009 guidance and guidance for post-split companies posted on encana.com
EnCana's 2009 guidance, which does not account for the proposed split, has been updated and the company has posted individual 2010 guidance for the post-split EnCana and Cenovus. Guidance documents are posted on the company's website at www.encana.com.

Financial strength

EnCana has a strong balance sheet, with 95 percent of outstanding debt composed of long-term, fixed-rate debt with an average remaining term of more than 13 years. The company has an upcoming debt maturity in 2010 of $200 million. At September 30, 2009, EnCana had available $4.3 billion in unused committed bank credit facilities. EnCana manages its financial strategy to achieve a strong investment grade credit rating. EnCana targets a debt to capitalization ratio of less than 40 percent and a debt to adjusted EBITDA ratio of less than 2.0 times. At September 30, 2009, the company's debt to capitalization ratio was 25 percent and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.1 times. None of these EnCana debt measures include the debt securities arranged for Cenovus.

Cenovus Energy financing
On September 18, 2009, in preparation for the anticipated split transaction, Cenovus Energy Inc., currently a wholly owned subsidiary of EnCana, completed a private offering of debt securities for an aggregate principal amount of $3.5 billion in three tranches, which are exempt from registration requirements of the U.S. Securities Act of 1933 under Rule 144A and Regulation S. The net proceeds of the private offering were placed into an escrow account pending the completion of the split transaction. In addition, Cenovus has obtained commitments from a syndicate of banks to make available, pending the completion of the split transaction, a C$2 billion 3-year revolving credit facility and a C$500 million 364-day revolving credit facility, both for general corporate purposes. The use of these credit facilities by Cenovus is subject to customary conditions for credit facilities of this type.

2010 Preliminary Budgets

2010 post-split EnCana and Cenovus Energy budgets designed with flexibility
For 2010, EnCana and Cenovus have developed preliminary capital investment budgets aimed at maintaining financial strength and balance sheet flexibility through disciplined management of capital investment and operating expenses.

"The budgets for the two independent companies are designed to follow EnCana's traditional investment principles. We employ a conservative and prudent approach and continually seek ways to reduce risk as we focus on our highest return opportunities in pursuit of enhancing the long-term value of every share," Eresman said.

"While there are definite signs of a worldwide economic recovery, the commodity and financial markets continue to experience some degree of uncertainty. In order to make it easier for the individual executive teams to respond quickly to changing economic and investment circumstances, a high level of flexibility has been built into each company's budget," said Eresman.

It is expected that these preliminary budgets will be updated once the respective executive teams and boards of directors have had a better chance to refine individual strategies following the completion of the planned split transaction. The preliminary budgets are presented using EnCana's current expectations and projections. The 2009 financial information for both Cenovus and post-split EnCana represents carved out data from EnCana projections including the operations, assets, liabilities and cash flows of the assets proposed for separation as well as a portion of the marketing and corporate functions of EnCana, which include some one-time transaction related costs for each company. The 2010 preliminary budget information in this interim report also refers to the assets that are proposed for separation and the estimated revenues and costs associated with operating those assets.

Post-split EnCana – preliminary budget forecast summary

Post-split EnCana 2010 Preliminary Budget Forecast[1]	
(US$ billions, excluding per share amounts)	2010 Forecast
Cash flow	4.0 – 4.6
Cash flow per share ($ per share diluted)	5.40 – 6.00
Capital investment	3.6 – 3.9
Total production (Bcfe/d) after royalties	3.2 – 3.3

1 2010 based on NYMEX gas of $5.50 to $6.15 per Mcf and WTI oil of $65.00 to $85.00 per bbl and the US$/C$ at $0.85 to $0.96. Cash flow and free cash flow are non-GAAP measures. See Note 1 on page 9.

EnCana – a leading unconventional natural gas company
"EnCana will continue to target being the best North American unconventional natural gas company. Our focus remains steadfast on being the lowest cost producer in all the fields where we operate as we employ a disciplined and methodical approach to unconventional natural gas development. We hold leading positions in key unconventional natural gas basins stretching from northeast British Columbia to east Texas and Louisiana," Eresman said.

"In 2010, we plan to invest between $3.6 and $3.9 billion in capital and target natural gas production growth of about 10 percent. Major investments are aimed at the company's large, early-stage opportunities in Haynesville and Horn River, as well as completion of the Deep Panuke project. Our budget is designed with the flexibility to adapt to changing economic conditions. Beyond what is currently planned, we have additional attractive investment opportunities that we may pursue if prices improve and market conditions warrant," Eresman said.

Investment in the USA Division is expected to be about $1.9 billion, with natural gas production expected to grow about 16 percent to about 1.8 Bcf/d. Close to 40 percent of the USA budget is planned for continued production growth and land retention in the emerging Haynesville opportunity. Average 2010 production from the play is expected to be about 240 MMcf/d net to EnCana.

About $1.6 billion of investment is planned for the Canadian Division (currently the Canadian Foothills Division) and is focused on expanding the production infrastructure for longer-term growth in the Horn River basin, continued Deep Basin developments in the Cutbank Ridge (including the Montney formation) and Bighorn resource plays, the coalbed methane (CBM) resource play, plus completion of the Deep Panuke project. With sizable investments directed to longer-term projects such as Horn River and Deep Panuke, production in Canada is expected to remain steady in 2010. The lack of production growth, despite those investments, can be attributed in part to dispositions in 2009 of non-core assets in the Canadian Division and price sensitive royalty rates in Alberta.

Cenovus Energy – preliminary budget forecast summary

Cenovus Energy 2010 Preliminary Budget Forecast[1]	
(US$ billions, excluding per share amounts)	2010 Forecast
Cash flow	2.3 – 2.6
Cash flow per share ($ per share diluted)	3.10 – 3.50
Capital investment	2.0 – 2.3
Foster Creek & Christina Lake oil production (bbls/d) after royalties	49,000 – 51,500

1 2010 based on WTI oil of $65.00 to $85.00 per bbl, a Chicago 3-2-1 crack spread of $7.50 to $9.50 per bbl, NYMEX gas of $5.50 to $6.15 per Mcf and the US$/C$ at $0.85 to $0.96. Cash flow and free cash flow are non-GAAP measures. See Note 1 on page 9.

"Cenovus Energy's expansive, high-quality bitumen reservoirs and cost-efficient refineries offer significant opportunities for our integrated oil company to deliver long-term shareholder value for years ahead. Cenovus has 1.4 million acres of existing, high-quality leases, which the company estimates contain approximately 40 billion barrels of original bitumen in place. In 2010, we plan a year of substantial investment both upstream and downstream as we set the stage for significant future growth. About 40 percent of our capital in 2010 is directed to building productive capacity that will provide growth beyond 2010," said Brian Ferguson, EnCana's Chief Financial Officer and designated President & Chief Executive Officer of Cenovus.

Cenovus's $2.0 to $2.3 billion of capital investment in 2010 is focused on increased development of the Foster Creek and Christina Lake enhanced oil operations, where 2010 production is expected to increase by 15 to 20 percent, and continued construction of the CORE project at Wood River.

Major capital investment in Cenovus's upstream operations in 2010 will help set the stage for future phases of significant production growth. Cenovus plans to invest about $550 million in upstream production capacity expansions, largely at Christina Lake. Construction of Christina Lake's phase C is on schedule and on budget and is expected to add about 40,000 bbls/d (20,000 bbls/d net to Cenovus) of capacity, with first production forecast in late 2011. The integrated oil business partners have sanctioned Christina Lake's phase D and construction on this 40,000 bbls/d (20,000 bbls/d net to Cenovus) expansion is expected to begin in 2010, with first production expected in 2013. Regulatory applications for Christina Lake phases E, F and G have also been filed, with each expansion designed to add approximately 40,000 bbls/d (20,000 bbls/d net to Cenovus) of productive capacity. Ultimately, Christina Lake is expected to have productive capacity in excess of 200,000 bbls/d (100,000 bbls/d net to Cenovus).

At Foster Creek, regulatory applications have been filed for phases F, G and H, which would each add 30,000 bbls/d of capacity, taking total expected capacity to 210,000 bbls/d (105,000 bbls/d net to Cenovus). Foster Creek and Christina Lake combined are expected to have the potential to produce more than 400,000 bbls/d (200,000 bbls/d net to Cenovus) when fully developed.

Close to one-quarter of the 2010 Cenovus capital investment, about $500 million, will be directed to the final stages of construction of the CORE project at the Wood River refinery. The CORE project is more than 65 percent complete as of the end of October and is expected to come on stream in 2011. The project is expected to increase refining capacity by 50,000 bbls/d to 356,000 bbls/d (178,000 bbls/d net to Cenovus), and more than double heavy crude oil refining capacity to 240,000 bbls/d (120,000 bbls/d net to Cenovus). Each of these enhancements is expected to increase Wood River's operating cash flow and improve refining margins.

Cenovus plans to invest about $700 million in Canadian Plains natural gas and oil production which is expected to generate strong operating cash flow, estimated in the range of $1.9 to $2.3 billion in 2010. These assets are a reliable source of free cash flow that will help fund future growth of enhanced oil production. Cenovus's extensive, low-cost shallow gas production also provides a natural price hedge for the natural gas volumes consumed at the company's enhanced oil projects and refineries.

Cenovus expected to use Canadian reporting protocols

For purposes of consistency, and in keeping with EnCana's historical reporting, all information is stated in U.S. dollars unless otherwise noted and follows U.S. protocols, which report natural gas and oil production, sales and reserves on an after-royalty basis. EnCana will continue to report using these protocols. Following the completion of the split transaction, Cenovus expects to report its results in Canadian dollars and its volumes on a before-royalty basis. This change in reporting is expected to commence with the first quarter of 2010. Each company has chosen its reporting protocols to facilitate an easier comparison with its respective industry peers.

NOTE 1: Non-GAAP measures

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

- Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows, in this interim report and interim financial statements.
- Free cash flow is a non-GAAP measure that EnCana defines as cash flow in excess of capital investment, excluding net acquisitions and divestitures, and is used to determine the funds available for other investing and/or financing activities.
- Operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain/loss on discontinuance, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, the after-tax foreign exchange gain/loss on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates. Management believes that these excluded items reduce the comparability of the company's underlying financial performance between periods. The majority of the U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- Capitalization is a non-GAAP measure defined as debt plus shareholders' equity. Debt to capitalization and debt to adjusted EBITDA are two ratios which management uses to steward the company's overall debt position as measures of the company's overall financial strength.
- Adjusted EBITDA is a non-GAAP measure defined as net earnings before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

These measures have been described and presented in this interim report in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

EnCana Corporation

With an enterprise value of approximately $50 billion, EnCana is a leading North American unconventional natural gas and integrated oil company. By partnering with employees, community organizations and other businesses, EnCana contributes to the strength and sustainability of the communities where it operates. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

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

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

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this interim report are forward-looking statements or information within the meaning of applicable securities legislation, collectively referred to herein as "forward-looking statements." Forward-looking statements in this interim report include, but are not limited to: future economic and operating performance (including per share growth, debt to capitalization ratio, debt to adjusted EBITDA ratio, sustainable growth and returns, free cash flow, cash flow, cash flow per share, operating earnings and increases in net asset value); projections contained in the company's and Cenovus's guidance forecasts and the anticipated ability to meet the company's and Cenovus's guidance forecasts; anticipated life of proved reserves; anticipated growth and success of resource plays and the expected characteristics of resource plays; anticipated production and drilling in the Horn River and Haynesville areas; anticipated 2010 budgets for EnCana and Cenovus (including cash flow, cash flow per share, free cash flow, capital investment, divestitures and total production); anticipated allocation of capital for EnCana and Cenovus in 2010, including among various projects; the potential success of such projects as Deep Panuke, Cutbank Ridge, Bighorn and CORE at Wood River; the ability of enhancements at Wood River to increase cash flow and improve refining margins; anticipated capacities at Foster Creek and Christina Lake; planned expansion of in-situ oil production; anticipated crude oil and natural gas prices, including basis differentials for various regions; anticipated expansion and production for various phases at Foster Creek and Christina Lake; anticipated divestitures; potential dividends; anticipated success of EnCana's price risk management strategy; anticipated hedging gains; potential demand for natural gas; anticipated drilling; estimates of original bitumen in place; potential capital expenditures and investment; potential oil, natural gas and NGLs production in 2009 and beyond; anticipated plans to bring production back on in the event of the recovery of natural gas prices; anticipated costs and cost reductions; the company's plans for splitting into two independent companies and the conditions which may be required therefor; and references to potential exploration. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: risks associated with the ability to obtain any necessary approvals, waivers, consents, court orders and other requirements necessary or desirable to permit or facilitate the planned split transaction (including regulatory and shareholder approvals); the risk that any applicable conditions of the planned split transaction may not be satisfied; volatility of and assumptions regarding oil and gas prices; assumptions based upon the company's current guidance, as well as assumptions based upon 2010 EnCana and Cenovus guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves; the ability of the company and ConocoPhillips to successfully manage and operate the integrated North American oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining crude oil; risks associated with technology; the company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the company operates; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.

Forward-looking information respecting anticipated 2009 cash flow for EnCana is based upon achieving average production of oil and gas for 2009 of approximately 4.4 to 4.8 Bcfe/d, year-to-date actuals and forward curve estimates for commodity prices and U.S./Canadian dollar foreign exchange rate as of September 30, 2009 and an average number of outstanding shares for EnCana of approximately 750 million. Forward-looking information respecting anticipated 2010 cash flow for EnCana is based upon achieving average production of oil and gas for 2010 of approximately 3.2 to 3.3 Bcfe/d, forward curve estimates for commodity prices and an estimated U.S./Canadian dollar foreign exchange rate of $0.85 to $0.96 and an average number of outstanding shares for EnCana of approximately 750 million. Forward-looking information respecting anticipated 2010 cash flow for Cenovus is based upon achieving average production of oil and NGLs for 2010 of approximately 105,000 to 111,500 bbls/d and average production of natural gas for 2010 of approximately 720 to 740 MMcf/d, forward curve estimates for commodity prices and an estimated U.S./Canadian dollar foreign exchange rate of $0.85 to $0.96 and an average number of outstanding shares for Cenovus of approximately 750 million. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this interim report.

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

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read with the unaudited Interim Consolidated Financial Statements ("Interim Consolidated Financial Statements") for the period ended September 30, 2009, the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2008, as well as EnCana's Information Circular Relating to an Arrangement Involving Cenovus Energy Inc. dated October 20, 2009. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document.

The Interim Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This document is dated November 11, 2009.

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

Proposed Arrangement

In May 2008, EnCana's Board of Directors unanimously approved a proposal to split EnCana into two independent energy companies – one a natural gas company and the other an integrated oil company. The proposed corporate reorganization (the "Arrangement") was expected to close in early January 2009.

In October 2008, EnCana announced the proposed Arrangement would be delayed until the global debt and equity markets regained stability.

On September 10, 2009, EnCana's Board of Directors unanimously approved plans to proceed with the proposed Arrangement. The proposed Arrangement is expected to be implemented through a court approved Plan of Arrangement and is subject to shareholder and regulatory approvals. The reorganization would result in two publicly traded entities with the names of Cenovus Energy Inc. and EnCana Corporation. Under the Arrangement, EnCana Shareholders will receive one New EnCana Common Share and one Cenovus Energy Inc. Common Share in exchange for each EnCana Common Share held.

Subject to court and shareholder approval, EnCana expects to complete the reorganization on November 30, 2009 following a Shareholders' meeting to vote on the proposed Plan of Arrangement to be held on November 25, 2009.

If the proposed Arrangement proceeds, there will be a significant and material effect on the operations and results of EnCana. Additional information on the effects of the proposed Arrangement can be found in EnCana's Information Circular dated October 20, 2009 that can be accessed under the Company's public filings found at www.sedar.com and also on the Company's website at www.encana.com.

EnCana's Financial Strategy in the Current Economic Environment

Global and national economic indicators suggest that the world's economies are showing promising signs of recovery. In this economic environment, EnCana continues to be highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, optimizing capital investments and continuing to pay a stable dividend to shareholders. This measured investment approach is underpinned by a strong balance sheet and a market risk mitigation strategy where EnCana has hedged, as of September 30, 2009, approximately 2 billion cubic feet per day ("Bcf/d") of gas using fixed price contracts from November 2009 to October 2010 at an average NYMEX equivalent price of $6.08 per Mcf. Additional actions within EnCana's risk management program are more fully described in the Risk Management section of this MD&A. During the first nine months of 2009, EnCana has benefited from its commodity price hedging program, which has resulted in realized hedging gains of $2.5 billion after-tax.

EnCana has a strong balance sheet and continues to employ a conservative capital structure. As at September 30, 2009, 95 percent of EnCana's outstanding debt, excluding the Cenovus Notes which are described more fully in the Financing

Activities section of this MD&A, was composed of long-term, fixed rate debt with an average remaining term of more than 13 years. The Company has an upcoming maturity of $200 million in 2010. As at September 30, 2009, excluding the Cenovus credit facilities, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.4 billion and unused committed bank credit facilities in the amount of $4.3 billion. EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times. At September 30, 2009, the Company's Debt to Capitalization ratio was 25 percent and Debt to Adjusted EBITDA was 1.1 times.

In addition, EnCana continues to monitor shut-in and curtailed production as well as expenses and capital programs. Additional detail regarding EnCana's 2009 capital investment is available in the Corporate Guidance on the Company's website at www.encana.com.

EnCana's Business

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

EnCana's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and natural gas liquids ("NGLs") and other related activities within the Canadian cost centre.
- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.
- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.
- **Corporate and Other** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization sells substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. Financial information is presented on an after eliminations basis.

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

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

2009 versus 2008 Results Review

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

- Announced its plan to proceed with the split into two independent energy companies;
- Reported a 26 percent decrease in Cash Flow to $2,079 million primarily due to lower commodity prices partially offset by realized hedging gains of $913 million after-tax in 2009 compared to losses of $271 million after-tax in 2008;
- Reported a 46 percent decrease in Operating Earnings to $775 million;
- Reported a 99 percent decrease in Net Earnings to $25 million. This was primarily due to lower commodity prices and the net impact in 2008 of an after-tax unrealized hedging gain of $2,043 million partially offset by a realized hedging loss of $271 million after-tax (see Summary of Hedging Impacts on Net Earnings in the Net Earnings section of this MD&A);
- Reported Free Cash Flow of $741 million compared to $1,221 million in 2008;
- Progressed construction on the Coker and Refinery Expansion ("CORE") project at the Wood River refinery to approximately 62 percent complete at September 30;
- Reported a 7 percent decrease in total production to 4,387 million cubic feet equivalent ("MMcfe") per day ("MMcfe/d") mainly attributable to shut-in and curtailed production and deliberately delayed well completions and tie-ins;
- Reported decreased production from natural gas key resource plays of 10 percent and increased production from oil key resource plays of 20 percent; and
- Reported a 64 percent decrease in average natural gas prices, excluding financial hedges, to $3.11 per thousand cubic feet ("Mcf") and a 42 percent decrease in average liquids prices, excluding financial hedges, to $57.40 per barrel ("bbl").

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

- Announced its plan to proceed with the split into two independent energy companies;
- Reported a 24 percent decrease in Cash Flow to $6,176 million primarily due to lower commodity prices partially offset by realized hedging gains of $2,512 million after-tax compared to losses of $658 million after-tax in 2008 and decreased expenses;
- Reported a 33 percent decrease in Operating Earnings to $2,640 million;
- Reported a 75 percent decrease in Net Earnings to $1,226 million primarily due to lower commodity prices;
- Reported Free Cash Flow of $2,252 million compared to $2,932 million in 2008;
- Progressed construction on the CORE project at the Wood River refinery to approximately 62 percent complete at September 30;
- Reported a 2 percent decrease in total production to 4,554 MMcfe/d mainly attributable to shut-in and curtailed production and deliberately delayed well completions and tie-ins;
- Reported decreased production from natural gas key resource plays of 1 percent and increased production from oil key resource plays of 18 percent; and
- Reported a 60 percent decrease in average natural gas prices, excluding financial hedges, to $3.50 per Mcf and a 49 percent decrease in average liquids prices, excluding financial hedges, to $46.58 per bbl.

Business Environment

EnCana's financial results are significantly influenced by fluctuations in commodity prices, which include price differentials and crack spreads, and the U.S./Canadian dollar exchange rate. EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found in the December 31, 2008 Management's Discussion and Analysis and Note 17 to the Interim Consolidated Financial Statements. The following table shows benchmark information on a quarterly basis to assist in understanding quarterly volatility in prices and foreign exchange rates that have impacted EnCana's financial results.

Quarterly Market Benchmark Prices and Foreign Exchange Rates

(Average for the period)	Nine Months Ended September 30 2009	2008	2009 Q3	Q2	Q1	2008 Q4	Q3	Q2	Q1	2007 Q4
Natural Gas Price Benchmarks										
AECO *(C$/Mcf)*	**$ 4.10**	$ 8.58	**$ 3.02**	$ 3.66	$ 5.63	$ 6.79	$ 9.24	$ 9.35	$ 7.13	$ 6.00
NYMEX *($/MMBtu)*	**3.92**	9.73	**3.39**	3.50	4.89	6.94	10.24	10.93	8.03	6.97
Rockies (Opal) *($/MMBtu)*	**2.79**	7.15	**2.69**	2.37	3.31	3.53	5.88	8.56	7.02	3.46
Texas (HSC) *($/MMBtu)*	**3.65**	9.43	**3.31**	3.44	4.21	6.37	9.98	10.58	7.73	6.64
Basis Differential *($/MMBtu)*										
AECO/NYMEX	**0.47**	1.28	**0.67**	0.39	0.35	1.10	1.28	1.71	0.84	0.85
Rockies/NYMEX	**1.13**	2.58	**0.70**	1.13	1.58	3.41	4.36	2.37	1.01	3.50
Texas/NYMEX	**0.27**	0.30	**0.08**	0.06	0.68	0.58	0.26	0.35	0.30	0.33
Crude Oil Price Benchmarks										
West Texas Intermediate (WTI) *($/bbl)*	**57.32**	113.52	**68.24**	59.79	43.31	59.08	118.22	123.80	97.82	90.50
Western Canadian Select (WCS) *($/bbl)*	**48.47**	93.16	**58.06**	52.37	34.38	39.95	100.22	102.18	76.37	56.85
Differential - WTI/WCS *($/bbl)*	**8.85**	20.36	**10.18**	7.42	8.93	19.13	18.00	21.62	21.45	33.65
Refining Margin Benchmark										
Chicago 3-2-1 Crack Spread *($/bbl)* (1)	**9.72**	12.86	**8.48**	10.95	9.75	6.31	17.29	13.60	7.69	9.17
Foreign Exchange										
U.S./Canadian Dollar Exchange Rate	**0.855**	0.982	**0.911**	0.857	0.803	0.825	0.961	0.990	0.996	1.019

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

Consolidated Financial Results

($ millions, except per share amounts)	Nine Months Ended September 30 2009	2008	2009 Q3	Q2	Q1	2008 Q4	Q3	Q2	Q1	2007 Q4
Total Consolidated										
Cash Flow (1)	**$ 6,176**	$ 8,087	**$ 2,079**	$ 2,153	$ 1,944	$ 1,299	$ 2,809	$ 2,889	$ 2,389	$ 1,934
- per share – diluted	**8.22**	10.75	**2.77**	2.87	2.59	1.73	3.74	3.85	3.17	2.56
Net Earnings	**1,226**	4,867	**25**	239	962	1,077	3,553	1,221	93	1,082
- per share – basic	**1.63**	6.49	**0.03**	0.32	1.28	1.44	4.74	1.63	0.12	1.44
- per share – diluted	**1.63**	6.47	**0.03**	0.32	1.28	1.43	4.73	1.63	0.12	1.43
Operating Earnings (2)	**2,640**	3,956	**775**	917	948	449	1,442	1,469	1,045	849
- per share – diluted	**3.51**	5.26	**1.03**	1.22	1.26	0.60	1.92	1.96	1.39	1.12
Cash Dividends – per share	**1.20**	1.20	**0.40**	0.40	0.40	0.40	0.40	0.40	0.40	0.20
Revenues, Net of Royalties	**12,251**	23,705	**3,881**	3,762	4,608	6,359	10,849	7,422	5,434	5,875

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

Cash Flow

Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. While Cash Flow is considered a non-GAAP measure, it is commonly used in the oil and gas industry and by EnCana to assist Management and investors in measuring the Company's ability to finance capital programs and meet financial obligations.

Summary of Cash Flow

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	**2009**	2008
Cash From Operating Activities	**$ 2,697**	$ 3,058	**$ 6,483**	$ 6,812
(Add back) deduct:				
Net change in other assets and liabilities	**10**	(19)	**33**	(283)
Net change in non-cash working capital	**608**	268	**274**	(992)
Cash Flow	**$ 2,079**	$ 2,809	**$ 6,176**	$ 8,087

Three Months Ended September 30, 2009 versus 2008

Cash Flow in 2009 decreased $730 million or 26 percent compared to 2008 as a result of:

- Average total natural gas prices, excluding financial hedges, decreased 64 percent to $3.11 per Mcf in 2009 compared to $8.74 per Mcf in 2008;
- Average total liquids prices, excluding financial hedges, decreased 42 percent to $57.40 per bbl in 2009 compared to $98.85 per bbl in 2008;
- Natural gas production volumes in 2009 decreased 9 percent to 3,551 million cubic feet (“MMcf”) per day (“MMcf/d”) from 3,917 MMcf/d in 2008 primarily as a result of shut-in and curtailed production and delayed well completions and tie-ins due to the low price environment; and

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $913 million after-tax in 2009 compared to losses of $271 million after-tax in 2008;
- Decreases in production and mineral taxes as well as transportation and selling expenses partially offset by increases in administrative expenses in 2009 compared to 2008;
- Operating Cash Flow from Downstream operations increased $182 million to $86 million in 2009; and
- Liquids production volumes in 2009 increased 4 percent to 139,262 barrels per day (“bbls/d”) from 133,556 bbls/d in 2008.

Nine Months Ended September 30, 2009 versus 2008

Cash Flow in 2009 decreased $1,911 million or 24 percent compared to 2008 as a result of:

- Average total natural gas prices, excluding financial hedges, decreased 60 percent to $3.50 per Mcf in 2009 compared to $8.78 per Mcf in 2008;
- Average total liquids prices, excluding financial hedges, decreased 49 percent to $46.58 per bbl in 2009 compared to $91.72 per bbl in 2008;
- Natural gas production volumes in 2009 decreased 2 percent to 3,735 MMcf/d from 3,830 MMcf/d in 2008 primarily as a result of shut-in and curtailed production and delayed well completions and tie-ins due to the low price environment; and
- Operating Cash Flow from Downstream operations decreased $40 million to $299 million in 2009;

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $2,512 million after-tax in 2009 compared to losses of $658 million after-tax in 2008;
- Decreases in operating, transportation and selling, production and mineral taxes, administrative and interest expenses in 2009 compared to 2008; and
- Liquids production volumes in 2009 increased 3 percent to 136,417 bbls/d from 132,818 bbls/d in 2008.

Net Earnings

Three Months Ended September 30, 2009 versus 2008

Net Earnings in 2009 of $25 million were $3,528 million lower compared to 2008. Significant items affecting Net Earnings were:

- Lower average total natural gas and total liquids prices, excluding financial hedges, as well as lower natural gas production volumes as discussed in the Cash Flow section of this MD&A;
- The net impact of realized and unrealized hedging, which resulted in an $18 million after-tax decrease to Net Earnings in 2009 compared to a $1,772 million after-tax increase to Net Earnings in 2008. Further information regarding hedging impacts on Net Earnings can be found in the table below;
- Long-term compensation costs of $42 million in 2009 compared to a recovery of $227 million in 2008 due to the change in the EnCana share price. A decline in the EnCana share price during the third quarter of 2008 resulted in a recovery of long-term compensation costs recognized in the period; and
- A gain of $99 million after-tax from the sale of interests in Brazil in 2008 with no comparative amount in 2009;

partially offset by:

- Non-operating foreign exchange gains of $181 million after-tax in 2009 compared to losses of $31 million after-tax in 2008;
- Lower costs of operations, increased Operating Cash Flow from Downstream operations and higher liquids production volumes as discussed in the Cash Flow section of this MD&A; and
- Depreciation, depletion and amortization ("DD&A") expenses decreased $103 million in 2009 compared to 2008 primarily due to lower production volumes and the lower U.S./Canadian dollar exchange rate.

Nine Months Ended September 30, 2009 versus 2008

Net Earnings in 2009 of $1,226 million were $3,641 million lower compared to 2008. Significant items affecting Net Earnings were:

- Lower average total natural gas and total liquids prices, excluding financial hedges, as well as lower natural gas production volumes and decreased Operating Cash Flow from Downstream operations as discussed in the Cash Flow section of this MD&A; and
- A gain of $99 million after-tax from the sale of interests in Brazil in 2008 with no comparative amount in 2009;

partially offset by:

- The net impact of realized and unrealized hedging, which resulted in a $920 million after-tax increase to Net Earnings in 2009 compared to a $413 million after-tax increase to Net Earnings in 2008. Further information regarding hedging impacts on Net Earnings can be found in the table below;
- Non-operating foreign exchange gains of $178 million after-tax in 2009 compared to losses of $259 million after-tax in 2008;
- Lower costs of operations and higher liquids production volumes as discussed in the Cash Flow section of this MD&A; and
- DD&A expenses decreased $272 million in 2009 compared to 2008 primarily due to the lower U.S./Canadian dollar exchange rate and lower production volumes.

Summary of Hedging Impacts on Net Earnings

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Unrealized Mark-to-Market Gains (Losses), after-tax (1)	**$ (931)**	$ 2,043	**$ (1,592)**	$ 1,071
Realized Hedging Gains (Losses), after-tax (2)	**913**	(271)	**2,512**	(658)
Hedging Impacts on Net Earnings	**$ (18)**	$ 1,772	**$ 920**	$ 413

(1) Included in Corporate and Other financial results. Further detail on unrealized mark-to-market gains (losses) can be found in the Corporate and Other section of this MD&A.

(2) Included in Divisional financial results.

Operating Earnings

Operating Earnings is a non-GAAP measure that adjusts Net Earnings by non-operating items that Management believes reduces the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings has been prepared to provide investors with information that is more comparable between periods.

Summary of Operating Earnings

	Three Months Ended September 30				Nine Months Ended September 30			
	2009		2008		2009		2008	
($ millions, except per share amounts)		Per share[4]		Per share[4]		Per share[4]		Per share[4]
Net Earnings, as reported	$ 25	$ 0.03	$ 3,553	$ 4.73	$ 1,226	$ 1.63	$ 4,867	$ 6.47
Add back (losses) and deduct gains:								
Unrealized mark-to-market accounting gain (loss), after-tax [1]	(931)	(1.24)	2,043	2.72	(1,592)	(2.12)	1,071	1.42
Non-operating foreign exchange gain (loss), after-tax [2]	181	0.24	(31)	(0.04)	178	0.24	(259)	(0.34)
Gain (loss) on discontinuance, after-tax	-	-	99	0.13	-	-	99	0.13
Operating Earnings [3]	$ 775	$ 1.03	$ 1,442	$ 1.92	$ 2,640	$ 3.51	$ 3,956	$ 5.26

(1) In the 2009 third quarter results, the unrealized mark-to-market accounting gains (losses), after-tax primarily represents the reversal of gains (losses) recognized in prior periods. The realized gains (losses), after-tax represents the recording of the final resulting settlement of hedge positions.
(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax realized foreign exchange gains (losses) on settlement of intercompany transactions and future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt . The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.
(3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gains (losses) on discontinuance, after-tax effect of unrealized mark-to-market accounting gains (losses) on derivative instruments, after-tax gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates. The Company's calculation of Operating Earnings excludes foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.
(4) Per Common Share - diluted.

Foreign Exchange

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate decreased 5 percent to $0.911 in the third quarter of 2009 compared to $0.961 in the third quarter of 2008 and decreased 13 percent to $0.855 in the nine months of 2009 compared to $0.982 in the nine months of 2008. The table below summarizes the impacts of these changes on EnCana's reported results when compared to the same periods in the prior year.

	Three Months Ended September 30, 2009		Nine Months Ended September 30, 2009	
Average U.S./Canadian Dollar Exchange Rate	$ 0.911		$ 0.855	
Change from comparative period in prior year	(0.050)		(0.127)	
($ millions, except $/Mcfe amounts)	$ millions	$/Mcfe	$ millions	$/Mcfe
Increase (decrease) in:				
Capital Investment	$ (37)		$ (294)	
Upstream Operating Expense	(15)	(0.04)	(126)	(0.10)
Other Operating Expense [1]	(1)		(6)	
Administrative Expense	(4)	(0.01)	(29)	(0.02)
DD&A Expense	(31)		(241)	

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

Results of Operations

Production Volumes

	Nine Months Ended September 30		2009			2008				2007
	2009	2008	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Produced Gas *(MMcf/d)*	**3,735**	3,830	**3,551**	3,788	3,869	3,858	3,917	3,841	3,733	3,722
Crude Oil *(bbls/d)*	**114,593**	106,507	**118,755**	112,968	111,981	110,628	106,826	101,153	111,538	108,958
NGLs *(bbls/d)*	**21,824**	26,311	**20,507**	22,685	22,299	25,222	26,730	26,450	25,750	27,179
Total *(MMcfe/d)* (1)	**4,554**	4,627	**4,387**	4,602	4,675	4,673	4,718	4,607	4,557	4,539

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

Key Resource Plays

	Three Months Ended September 30					Nine Months Ended September 30				
	Daily Production			Drilling Activity (net wells drilled)		Daily Production			Drilling Activity (net wells drilled)	
	2009	2009 vs 2008	2008	2009	2008	2009	2009 vs 2008	2008	2009	2008
Natural Gas *(MMcf/d)*										
Jonah	**521**	**-15%**	615	**20**	43	**573**	**-7%**	613	**85**	135
Piceance	**334**	**-18%**	407	**25**	94	**358**	**-7%**	387	**113**	258
East Texas	**305**	**-10%**	339	**4**	22	**339**	**10%**	309	**30**	55
Fort Worth	**135**	**-9%**	148	**1**	21	**141**	**-1%**	142	**23**	62
Greater Sierra	**189**	**-17%**	228	**17**	29	**206**	**-5%**	217	**42**	92
Cutbank Ridge	**322**	**-**	322	**18**	17	**328**	**13%**	291	**56**	65
Bighorn	**154**	**-17%**	185	**17**	11	**165**	**-1%**	167	**52**	59
CBM	**318**	**3%**	309	**37**	78	**319**	**5%**	303	**316**	339
Shallow Gas	**649**	**-6%**	691	**55**	233	**661**	**-6%**	706	**436**	812
	2,927	**-10%**	3,244	**194**	548	**3,090**	**-1%**	3,135	**1,153**	1,877
Oil *(bbls/d)*										
Foster Creek	**38,954**	**44%**	26,979	**2**	6	**33,830**	**36%**	24,936	**18**	19
Christina Lake	**6,097**	**33%**	4,568	**-**	-	**6,360**	**76%**	3,606	**-**	-
	45,051	**43%**	31,547	**2**	6	**40,190**	**41%**	28,542	**18**	19
Pelican Lake	**20,566**	**-7%**	22,196	**-**	-	**20,354**	**-10%**	22,510	**5**	-
Weyburn	**14,947**	**10%**	13,590	**-**	4	**15,423**	**14%**	13,583	**-**	18
	80,564	**20%**	67,333	**2**	10	**75,967**	**18%**	64,635	**23**	37
Total *(MMcfe/d)*	**3,410**	**-7%**	3,648	**196**	558	**3,546**	**1%**	3,523	**1,176**	1,914

Total production volumes decreased 7 percent or 331 MMcfe/d in the third quarter of 2009 compared to the third quarter of 2008 primarily due to decreased production from EnCana's natural gas key resource plays of 10 percent, mainly attributable to shut-in and curtailed production and delayed well completions and tie-ins due to the low price environment, as well as natural declines in conventional properties partially offset by a 43 percent increase in production volumes at the Foster Creek/Christina Lake key resource plays and lower royalties in other properties.

Total production volumes decreased 2 percent or 73 MMcfe/d in the nine months of 2009 compared to the nine months of 2008 primarily due to natural declines in conventional properties as well as shut-in and curtailed production and delayed well completions and tie-ins due to the low price environment partially offset by a 41 percent increase in production volumes at the Foster Creek/Christina Lake key resource plays and lower royalties in other properties.

Operating Netback Information

	Three Months Ended September 30					
	2009			2008		
	Gas ($/Mcf)	**Liquids ($/bbl)**	**Total ($/Mcfe)**	Gas ($/Mcf)	Liquids ($/bbl)	Total ($/Mcfe)
Price	**$ 3.11**	**$ 57.40**	**$ 4.36**	$ 8.74	$ 98.85	$ 10.04
Expenses						
Production and mineral taxes	**0.05**	**0.95**	**0.07**	0.31	2.09	0.32
Transportation and selling	**0.58**	**1.54**	**0.52**	0.57	1.72	0.53
Operating	**0.78**	**8.30**	**0.90**	0.61	8.66	0.75
Netback excluding Realized Financial Hedging	**1.70**	**46.61**	**2.87**	7.25	86.38	8.44
Realized Financial Hedging Gain (Loss)	**4.20**	**(0.01)**	**3.39**	(0.80)	(7.97)	(0.89)
Netback including Realized Financial Hedging	**$ 5.90**	**$ 46.60**	**$ 6.26**	$ 6.45	$ 78.41	$ 7.55

	Nine Months Ended September 30					
	2009			2008		
	Gas ($/Mcf)	**Liquids ($/bbl)**	**Total ($/Mcfe)**	Gas ($/Mcf)	Liquids ($/bbl)	Total ($/Mcfe)
Price	**$ 3.50**	**$ 46.58**	**$ 4.26**	$ 8.78	$ 91.72	$ 9.90
Expenses						
Production and mineral taxes	**0.09**	**0.92**	**0.10**	0.32	1.88	0.32
Transportation and selling	**0.52**	**1.49**	**0.47**	0.56	1.62	0.51
Operating	**0.76**	**8.38**	**0.87**	0.87	10.30	1.02
Netback excluding Realized Financial Hedging	**2.13**	**35.79**	**2.82**	7.03	77.92	8.05
Realized Financial Hedging Gain (Loss)	**3.68**	**1.06**	**3.05**	(0.61)	(8.23)	(0.74)
Netback including Realized Financial Hedging	**$ 5.81**	**$ 36.85**	**$ 5.87**	$ 6.42	$ 69.69	$ 7.31

Netbacks, excluding financial hedges, decreased significantly during the third quarter and nine months of 2009 compared to 2008 primarily due to lower commodity prices partially offset by lower total expenses and the impact of the lower U.S./Canadian dollar exchange rate.

As part of ongoing efforts to maintain financial resilience and flexibility, EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found in the December 31, 2008 Management's Discussion and Analysis and Note 17 to the Interim Consolidated Financial Statements. As evidenced in the table above, EnCana has benefited significantly from its hedging program during this period of weaker commodity prices.

Net Capital Investment

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Canada				
Canadian Plains	**$ 104**	$ 173	**$ 332**	$ 593
Canadian Foothills	**505**	473	**1,250**	1,836
Integrated Oil – Canada	**111**	142	**340**	494
USA	**346**	621	**1,271**	1,800
Downstream Refining	**266**	133	**695**	310
Market Optimization	**1**	4	**(2)**	11
Corporate & Other	**5**	42	**38**	111
Capital Investment	**1,338**	1,588	**3,924**	5,155
Acquisitions	**15**	878	**128**	1,214
Divestitures	**(977)**	(442)	**(1,030)**	(593)
Net Capital Investment	**$ 376**	$ 2,024	**$ 3,022**	$ 5,776

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

Capital investment during the nine months of 2009 was primarily focused on continued development of EnCana's North American key resource plays and expansion of the Company's downstream heavy oil refining capacity through its joint venture with ConocoPhillips. Reported capital investment was lower due to reduced upstream activity levels as well as the change in the average U.S./Canadian dollar exchange rate, which decreased capital investment by $294 million in the nine months of 2009 compared to the same period in 2008. Further information regarding the Company's capital investment can be found in the Divisional Results section of this MD&A.

Acquisitions and Divestitures

On May 5, 2009, the Company acquired the common shares of Kerogen Resources Canada, ULC for net cash consideration of $24 million. The acquisition included $37 million of property, plant and equipment and the assumption of $6 million of current liabilities and $7 million of future income taxes. The operations are included in the Canadian Foothills Division. Acquisitions in the nine months of 2008 included land purchases of approximately $1,089 million in the Haynesville Shale play in Louisiana.

In the nine months of 2009, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of $957 million (2008 – $218 million) in Canadian Foothills and $70 million (2008 – $123 million) in the USA. In September 2008, the Company completed the sale of its interests in Brazil for net proceeds of $164 million resulting in a gain on sale of $124 million. After recording income tax of $25 million, EnCana recorded an after-tax gain of $99 million.

The Company also had some other minor property acquisitions and divestitures in the nine months of 2009 and 2008.

In early November 2009, EnCana sold its Senlac heavy oil assets in west central Saskatchewan for approximately $83 million.

Free Cash Flow

EnCana's third quarter 2009 Free Cash Flow of $741 million and nine months 2009 Free Cash Flow of $2,252 million were lower compared to the same periods in 2008. Reasons for the decrease in total Cash Flow and Capital Investment are discussed under the Cash Flow and Net Capital Investment sections of this MD&A.

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Cash Flow (1)	**$ 2,079**	$ 2,809	**$ 6,176**	$ 8,087
Capital Investment	**1,338**	1,588	**3,924**	5,155
Free Cash Flow (2)	**$ 741**	$ 1,221	**$ 2,252**	$ 2,932

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

(2) Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of Capital Investment, excluding net acquisitions and divestitures, and is used by Management to determine the funds available for other investing activities, dividends and/or other financing activities.

Divisional Results

EnCana Post-Arrangement Operating Divisions

As discussed in EnCana's Business section of this MD&A, the Company announced its plan to split into two independent energy companies. EnCana's divisions, post-Arrangement, will include Canadian Foothills and USA.

CANADIAN FOOTHILLS

Financial Results

Three Months Ended September 30, 2009 versus 2008

	2009				2008			
($ millions)	Gas	Oil & NGLs	Other	Total	Gas	Oil & NGLs	Other	Total
Revenues, Net of Royalties and Hedging	$ 314	$ 77	$ 11	$ 402	$ 1,123	$ 189	$ 14	$ 1,326
Realized Financial Hedging Gain (Loss)	447	-	-	447	(141)	(17)	-	(158)
Expenses								
Production and mineral taxes	2	-	-	2	12	2	-	14
Transportation and selling	38	2	-	40	54	3	-	57
Operating	118	5	3	126	108	7	5	120
Operating Cash Flow	$ 603	$ 70	$ 8	$ 681	$ 808	$ 160	$ 9	$ 977

Nine Months Ended September 30, 2009 versus 2008

	2009				2008			
($ millions)	Gas	Oil & NGLs	Other	Total	Gas	Oil & NGLs	Other	Total
Revenues, Net of Royalties and Hedging	$ 1,232	$ 208	$ 31	$ 1,471	$ 3,159	$ 542	$ 47	$ 3,748
Realized Financial Hedging Gain (Loss)	1,200	-	-	1,200	(268)	(48)	-	(316)
Expenses								
Production and mineral taxes	11	2	-	13	26	4	-	30
Transportation and selling	109	6	-	115	158	9	-	167
Operating	362	17	10	389	432	30	16	478
Operating Cash Flow	$ 1,950	$ 183	$ 21	$ 2,154	$ 2,275	$ 451	$ 31	$ 2,757

Production Volumes

	Nine Months Ended September 30		2009			2008				2007
	2009	2008	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Produced Gas *(MMcf/d)*	1,275	1,299	1,201	1,343	1,281	1,302	1,351	1,289	1,256	1,313
Crude Oil *(bbls/d)*	7,623	8,486	6,943	7,800	8,140	8,437	8,217	8,376	8,867	8,441
NGLs *(bbls/d)*	9,404	11,588	8,966	9,824	9,427	11,265	11,730	11,779	11,256	10,966
Total *(MMcfe/d)* (1)	1,377	1,419	1,296	1,449	1,386	1,420	1,471	1,410	1,377	1,429

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

Produced Gas

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $221 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $659 million impact resulting from a 68 percent decrease in natural gas prices, excluding the impact of financial hedging; and

- A $150 million impact resulting from an 11 percent decrease in natural gas production volumes. Produced gas volumes decreased in the third quarter of 2009 as a result of delayed well completions and tie-ins due to the low price environment, program deferrals and shut-in volumes as well as natural declines at conventional properties and the volume impact of property divestitures in 2008 and 2009 partially offset by lower royalties;

partially offset by:

- Realized financial hedging gains of $447 million or $4.15 per Mcf in 2009 compared to losses of $141 million or $1.13 per Mcf in 2008.

The decrease in Canadian Foothills natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials.

Canadian Foothills production and mineral taxes of $2 million in 2009 decreased $10 million or 83 percent compared to 2008 primarily as a result of lower natural gas prices.

Canadian Foothills natural gas transportation and selling costs of $38 million in 2009 decreased $16 million or 30 percent compared to 2008 due to lower volumes transported to the U.S and the lower U.S./Canadian dollar exchange rate.

Canadian Foothills natural gas operating expenses of $118 million in 2009 were $10 million or 9 percent higher compared to 2008 primarily as a result of higher long-term compensation costs due to the change in the EnCana share price partially offset by the lower U.S./Canadian dollar exchange rate, reduced repairs and maintenance costs due to less activity and lower electricity costs.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $459 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $1,831 million impact resulting from a 60 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $96 million impact resulting from a 2 percent decrease in natural gas production volumes. Produced gas volumes decreased in the nine months of 2009 as a result of delayed well completions and tie-ins due to the low price environment, program deferrals and shut-in volumes as well as natural declines at conventional properties and the volume impact of property divestitures in 2008 and 2009 partially offset by the impact of lower royalties;

partially offset by:

- Realized financial hedging gains of $1,200 million or $3.48 per Mcf in 2009 compared to losses of $268 million or $0.75 per Mcf in 2008.

The decrease in Canadian Foothills natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials.

Canadian Foothills production and mineral taxes of $11 million in 2009 decreased $15 million or 58 percent compared to 2008 primarily as a result of lower natural gas prices.

Canadian Foothills natural gas transportation and selling costs of $109 million in 2009 decreased $49 million or 31 percent compared to 2008 due to the lower U.S./Canadian dollar exchange rate and lower volumes transported to the U.S.

Canadian Foothills natural gas operating expenses of $362 million in 2009 were $70 million or 16 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, reduced repairs and maintenance costs due to less activity and lower electricity costs.

Crude Oil and NGLs

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $95 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $74 million impact resulting from a 47 percent decrease in crude oil prices and 51 percent decrease in NGLs prices, excluding financial hedges; and
- A $38 million impact resulting from a 16 percent decrease in crude oil volumes and 24 percent decrease in NGLs volumes. The decreases were due to natural declines and the volume impact of property divestitures;

partially offset by:

- Realized financial hedging losses on liquids of $17 million or $9.20 per bbl in 2008, with no comparable amount in 2009.

Canadian Foothills crude oil prices decreased 47 percent to $59.46 per bbl in 2009 from $112.73 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices and changes in the average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were approximately $7 million or $9.53 per bbl in 2008, with no comparable amount in 2009.

Canadian Foothills NGLs prices decreased 51 percent to $47.08 per bbl in 2009 from $95.49 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $286 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $250 million impact resulting from a 54 percent decrease in crude oil prices and 56 percent decrease in NGLs prices, excluding financial hedges; and
- An $84 million impact resulting from a 10 percent decrease in crude oil volumes and 19 percent decrease in NGLs volumes. The decreases were due to natural declines and the volume impact of property divestitures;

partially offset by:

- Realized financial hedging losses on liquids of less than $1 million in 2009 compared to losses of $48 million or $8.70 per bbl in 2008.

Canadian Foothills crude oil prices decreased 54 percent to $49.52 per bbl in 2009 from $106.53 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices and changes in the average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were less than $1 million in 2009 compared to losses of approximately $20 million or $8.61 per bbl in 2008.

Canadian Foothills NGLs prices decreased 56 percent to $40.92 per bbl in 2009 from $92.69 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Foothills crude oil operating costs of $17 million in 2009 were $13 million or 43 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate, lower electricity costs and lower workover costs. NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

Capital Investment

Canadian Foothills capital investment of $1,250 million during the nine months of 2009 was primarily focused on the coalbed methane (“CBM”), Cutbank Ridge, Greater Sierra and Bighorn key resource plays. The $586 million decrease compared to 2008 was primarily due to lower drilling and completion costs as well as the lower U.S./Canadian dollar exchange rate partially offset by higher activity in Deep Panuke. Canadian Foothills drilled 476 net wells in the nine months of 2009 compared to 641 net wells in 2008.

USA

Financial Results

Three Months Ended September 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	**$ 477**	**$ 53**	**$ 24**	**$ 554**	$ 1,315	$ 124	$ 90	$ 1,529
Realized Financial Hedging Gain (Loss)	**607**	**-**	**-**	**607**	(52)	-	-	(52)
Expenses								
Production and mineral taxes	**12**	**5**	**-**	**17**	86	11	-	97
Transportation and selling	**139**	**-**	**-**	**139**	132	-	-	132
Operating	**78**	**-**	**22**	**100**	59	-	68	127
Operating Cash Flow	**$ 855**	**$ 48**	**$ 2**	**$ 905**	$ 986	$ 113	$ 22	$ 1,121

Nine Months Ended September 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	**$ 1,520**	**$ 132**	**$ 83**	**$ 1,735**	$ 3,945	$ 353	$ 249	$ 4,547
Realized Financial Hedging Gain (Loss)	**1,726**	**-**	**-**	**1,726**	(191)	-	-	(191)
Expenses								
Production and mineral taxes	**66**	**12**	**-**	**78**	280	31	-	311
Transportation and selling	**387**	**-**	**-**	**387**	367	-	-	367
Operating	**237**	**-**	**77**	**314**	266	-	216	482
Operating Cash Flow	**$ 2,556**	**$ 120**	**$ 6**	**$ 2,682**	$ 2,841	$ 322	$ 33	$ 3,196

Production Volumes

	Nine Months Ended September 30		2009			2008				2007
	2009	2008	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Produced Gas *(MMcf/d)*	**1,616**	1,618	**1,524**	1,581	1,746	1,677	1,674	1,629	1,552	1,464
NGLs *(bbls/d)*	**11,227**	13,524	**10,325**	11,699	11,671	12,831	13,853	13,482	13,232	14,791
Total *(MMcfe/d)* (1)	**1,683**	1,699	**1,586**	1,651	1,816	1,754	1,757	1,710	1,631	1,553

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

Produced Gas

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $179 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $720 million impact resulting from a 60 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $118 million impact resulting from a 9 percent decrease in natural gas production volumes. Produced gas volumes in the USA decreased in the third quarter of 2009 primarily as a result of shut-in and curtailed production as well as delayed well completions due to the low price environment partially offset by drilling and operational success;

partially offset by:

- Realized financial hedging gains of $607 million or $4.33 per Mcf in 2009 compared to losses of $52 million or $0.34 per Mcf in 2008.

The decrease in USA natural gas prices in 2009, excluding the impact of financial hedges, reflects the changes in NYMEX, Rockies (Opal) and Texas (HSC) benchmark prices and changes in the basis differentials.

Natural gas production and mineral taxes for the USA of $12 million in 2009 decreased $74 million or 86 percent compared to 2008 primarily as a result of lower natural gas prices.

Natural gas operating expenses for the USA of $78 million in 2009 were $19 million or 32 percent higher compared to 2008 as a result of higher long-term compensation costs due to the change in the EnCana share price partially offset by well shut-ins and less activity resulting in lower labour, repairs and maintenance, water disposal and hauling and workover costs.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $508 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $2,406 million impact resulting from a 61 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $19 million impact resulting from a slight decrease in natural gas production volumes. Drilling and operational success in Haynesville and East Texas were offset by shut-in and curtailed production as well as delayed well completions due to the low price environment;

partially offset by:

- Realized financial hedging gains of $1,726 million or $3.91 per Mcf in 2009 compared to losses of $191 million or $0.43 per Mcf in 2008.

The decrease in USA natural gas prices in 2009, excluding the impact of financial hedges, reflects the changes in NYMEX, Rockies (Opal) and Texas (HSC) benchmark prices and changes in the basis differentials.

Natural gas production and mineral taxes for the USA of $66 million in 2009 decreased $214 million or 76 percent compared to 2008 primarily as a result of lower natural gas prices and high cost well tax credits.

Natural gas transportation and selling costs for the USA of $387 million in 2009 increased $20 million or 5 percent compared to 2008 primarily as a result of higher unutilized transportation commitments.

Natural gas operating expenses for the USA of $237 million in 2009 were $29 million or 11 percent lower compared to 2008 as a result of well shut-ins and less activity resulting in lower repairs and maintenance, labour, water disposal and hauling and workover costs.

Crude Oil and NGLs

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

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $71 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $39 million impact resulting from a 43 percent decrease in NGLs prices; and
- A $32 million impact resulting from a 25 percent decrease in NGLs volumes.

USA NGLs prices decreased 43 percent to $55.60 per bbl in 2009 from $97.63 per bbl in 2008 primarily as a result of the change in the WTI benchmark price.

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $221 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $160 million impact resulting from a 55 percent decrease in NGLs prices; and
- A $61 million impact resulting from a 17 percent decrease in NGLs volumes.

USA NGLs prices decreased 55 percent to $43.05 per bbl in 2009 from $95.35 per bbl in 2008 primarily as a result of the change in the WTI benchmark price.

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

Capital Investment

USA capital investment of $1,271 million during the nine months of 2009 was primarily focused on the East Texas and Jonah key resource plays, as well as one of EnCana's emerging shale plays at Haynesville. The $529 million decrease compared to 2008 was primarily due to lower activity in the Piceance, East Texas, Jonah and Fort Worth key resource plays partially offset by increased drilling and facility spending in Haynesville. The number of net wells drilled in the USA in the nine months of 2009 decreased to 319 from 571 in 2008.

Cenovus Post-Arrangement Operating Divisions

As discussed in EnCana's Business section of this MD&A, the Company announced its plan to split into two independent energy companies. Cenovus's divisions, post-Arrangement, will include Integrated Oil and Canadian Plains.

INTEGRATED OIL

Foster Creek/Christina Lake Operations

EnCana is a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes contributed assets from EnCana, primarily the Foster Creek and Christina Lake oil properties while the downstream entity includes ConocoPhillips' Wood River and Borger refineries located in Illinois and Texas, respectively.

The current plan of the upstream business is to increase production capacity at Foster Creek/Christina Lake to approximately 218,000 bbls/d (on a 100 percent basis) of bitumen with the completion of current expansion phases in 2013.

Financial Results

Three Months Ended September 30, 2009 versus 2008

	Oil	
($ millions)	**2009**	2008
Revenues, Net of Royalties and Hedging	**$ 345**	$ 383
Realized Financial Hedging Gain (Loss)	**-**	(21)
Expenses		
Transportation and selling	**120**	137
Operating	**45**	42
Operating Cash Flow	**$ 180**	$ 183

Nine Months Ended September 30, 2009 versus 2008

	Oil	
($ millions)	**2009**	2008
Revenues, Net of Royalties and Hedging	**$ 748**	$ 977
Realized Financial Hedging Gain (Loss)	**37**	(79)
Expenses		
Transportation and selling	**286**	380
Operating	**123**	133
Operating Cash Flow	**$ 376**	$ 385

Production Volumes

	Nine Months Ended September 30		2009			2008				2007
	2009	2008	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Crude Oil *(bbls/d)*	**40,190**	28,542	**45,051**	40,677	34,729	35,068	31,547	24,671	29,376	27,190
Total *(MMcfe/d)* (1)	**241**	171	**270**	244	208	210	189	148	176	163

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

Crude Oil

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $17 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $142 million impact resulting from a decrease in crude oil prices, excluding financial hedges;
- A $22 million impact resulting from a decrease in average prices of condensate partially offset by an increase in condensate volumes used for blending with heavy oil;

partially offset by:

- A $126 million impact resulting from a 50 percent increase in crude oil sales volumes attributable to a 43 percent increase in production volumes and changes in inventory levels; and
- Realized financial hedging losses primarily on condensate used for blending of less than $1 million in 2009 compared to losses of $21 million in 2008.

Foster Creek/Christina Lake bitumen prices decreased 37 percent to $57.12 per bbl in 2009 from $91.21 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices which includes changes in the average differentials. WCS as a percentage of WTI was 85 percent in 2009 and 2008.

Crude oil transportation and selling costs of $120 million in 2009 decreased $17 million or 12 percent compared to 2008 primarily due to a decrease in average prices of condensate partially offset by an increase in condensate volumes used for blending with heavy oil and variability in sales destinations and pipelines utilized to transport the product.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $113 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $393 million impact resulting from a decrease in crude oil prices, excluding financial hedges;
- A $104 million impact resulting from a decrease in average prices of condensate partially offset by an increase in condensate volumes used for blending with heavy oil;

partially offset by:

- A $268 million impact resulting from a 44 percent increase in crude oil sales volumes attributable to a 41 percent increase in production volumes and changes in inventory levels; and
- Realized financial hedging gains primarily on condensate used for blending of $37 million in 2009 compared to losses of $79 million in 2008.

Foster Creek/Christina Lake bitumen prices decreased 44 percent to $45.41 per bbl in 2009 from $81.64 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices which includes changes in the average differentials. WCS as a percentage of WTI was 85 percent in 2009 compared to 82 percent in 2008.

Crude oil transportation and selling costs of $286 million in 2009 decreased $94 million or 25 percent compared to 2008 primarily due to a decrease in average prices of condensate partially offset by an increase in condensate volumes used for blending with heavy oil and variability in sales destinations and pipelines utilized to transport the product.

Crude oil operating costs of $123 million in 2009 were $10 million or 8 percent lower compared to 2008 mainly due to lower fuel gas costs and the lower U.S./Canadian dollar exchange rate partially offset by increased workover and repairs and maintenance costs.

Downstream Operations

Financial Results

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Revenues	**$ 1,610**	$ 2,699	**$ 3,849**	$ 7,514
Expenses				
Operating	**99**	116	**329**	375
Purchased product	**1,425**	2,679	**3,221**	6,800
Operating Cash Flow	**$ 86**	$ (96)	**$ 299**	$ 339

The Wood River refinery, located in Roxana, Illinois, has a current capacity of approximately 306,000 bbls/d of crude oil (on a 100 percent basis).

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

The current plan of the downstream business is to refine approximately 275,000 bbls/d (on a 100 percent basis) of heavy crude oil (approximately 150,000 bbls/d of bitumen equivalent) to primarily motor fuels upon the completion of the Wood River CORE project in 2011. As at September 30, 2009, the Wood River and Borger refineries had processing capability to refine approximately 145,000 bbls/d (on a 100 percent basis) of heavy crude oil (approximately 70,000 bbls/d of bitumen equivalent).

The two refineries have a combined crude oil refining capacity of approximately 452,000 bbls/d (on a 100 percent basis) and operated at an average 94 percent of that capacity during the third quarter of 2009 compared to 91 percent in 2008 and 90 percent during the nine months of 2009 compared to 93 percent in 2008. Refinery crude utilization was lower in 2009 primarily due to unplanned refinery unit outages and maintenance activities. Refined products averaged 451,000 bbls/d (225,500 bbls/d net to EnCana) in the third quarter of 2009 compared to 438,000 bbls/d (219,000 bbls/d net to EnCana) in 2008 and 433,000 bbls/d (216,500 bbls/d net to EnCana) in the nine months of 2009 compared to 446,000 bbls/d (223,000 bbls/d net to EnCana) in 2008.

Three Months Ended September 30, 2009 versus 2008

Operating Cash Flow increased $182 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $139 million increase resulting from lower purchased product costs in 2009 compared to 2008 when higher priced product was drawn out of inventory for processing;
- A $26 million increase resulting mainly from improved margins on fixed price refined products combined with higher refinery utilization; and
- A $17 million reduction of operating expenses mainly due to lower energy costs.

Nine Months Ended September 30, 2009 versus 2008

Operating Cash Flow decreased $40 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $72 million decrease due to weaker refinery margins combined with lower refinery utilization;

partially offset by:

- A $46 million reduction of operating expenses mainly due to lower energy costs.

Other Integrated Oil Operations

In addition to the 50 percent owned Foster Creek/Christina Lake operations, Integrated Oil also manages the 100 percent owned natural gas operations in Athabasca and crude oil operations in Senlac.

Gas production volumes from Athabasca were 51 MMcf/d in the third quarter of 2009 compared to 61 MMcf/d in 2008. The decrease in production volumes was the result of increased internal usage of natural gas to supply a portion of the fuel gas requirements at Foster Creek and expected natural declines. Production volumes were 55 MMcf/d in the nine months of 2009 compared to 64 MMcf/d in 2008 primarily due to increased internal usage of gas and expected natural declines.

Oil production volumes from Senlac were 4,401 bbls/d in the third quarter of 2009 compared to 2,273 bbls/d in 2008 and 2,765 bbls/d in the nine months of 2009 compared to 2,930 bbls/d in 2008. The increase in volumes at Senlac during the third quarter of 2009 was a result of new wells coming on production.

In early November 2009, EnCana sold its Senlac heavy oil assets in west central Saskatchewan for approximately $83 million.

Capital Investment

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Integrated Oil – Canada	**$ 111**	$ 142	**$ 340**	$ 494
Downstream Refining	**266**	133	**695**	310
Total Integrated Oil Division	**$ 377**	$ 275	**$ 1,035**	$ 804

Integrated Oil Division capital investment of $1,035 million during the nine months of 2009 was primarily focused on continued development of the Foster Creek and Christina Lake key resource plays and on the CORE project at the Wood River refinery. The $231 million increase in capital investment in the nine months of 2009 compared to the same period in 2008 was primarily due to:

- Spending related to the Wood River CORE project increased $354 million to $571 million in the first nine months of 2009 compared to $217 million in the same period in 2008. The CORE project is expected to cost approximately $1.8 billion net to EnCana and is anticipated to be completed and in operation in 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and more than double heavy crude oil refining capacity at Wood River to 240,000 bbls/d (on a 100 percent basis) . At September 30, 2009, construction on the CORE project was approximately 62 percent complete;

partially offset by:

- Lower facility costs with substantial completion of the Foster Creek Phases D and E expansions late in the fourth quarter of 2008. These expansions have increased plant capacity to 120,000 bbls/d (on a 100 percent basis);
- Lower drilling costs mainly due to drilling fewer stratigraphic test wells (net to EnCana 2009 – 40; 2008 – 137) at Foster Creek, Christina Lake, Borealis and Senlac related to the next phases of development; and
- The lower U.S./Canadian dollar exchange rate.

CANADIAN PLAINS

Financial Results

Three Months Ended September 30, 2009 versus 2008

	2009				2008			
($ millions)	**Gas**	**Oil & NGLs**	**Other**	**Total**	Gas	Oil & NGLs	Other	Total
Revenues, Net of Royalties and Hedging	**$ 204**	**$ 385**	**$ 3**	**$ 592**	$ 663	$ 689	$ 4	$ 1,356
Realized Financial Hedging Gain (Loss)	**283**	**-**	**-**	**283**	(87)	(56)	-	(143)
Expenses								
Production and mineral taxes	**3**	**6**	**-**	**9**	14	13	-	27
Transportation and selling	**10**	**38**	**-**	**48**	18	88	-	106
Operating	**56**	**55**	**-**	**111**	44	51	1	96
Operating Cash Flow	**$ 418**	**$ 286**	**$ 3**	**$ 707**	$ 500	$ 481	$ 3	$ 984

Nine Months Ended September 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	**$ 755**	**$ 975**	**$ 9**	**$ 1,739**	$ 1,966	$ 1,989	$ 8	$ 3,963
Realized Financial Hedging Gain (Loss)	**728**	**3**	**-**	**731**	(171)	(163)	-	(334)
Expenses								
Production and mineral taxes	**11**	**19**	**-**	**30**	32	32	-	64
Transportation and selling	**31**	**132**	**-**	**163**	55	275	-	330
Operating	**158**	**161**	**3**	**322**	191	191	3	385
Operating Cash Flow	**$ 1,283**	**$ 666**	**$ 6**	**$ 1,955**	$ 1,517	$ 1,328	$ 5	$ 2,850

Production Volumes

	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	2008 Q2	2008 Q1	2007 Q4
Produced Gas *(MMcf/d)*	**789**	849	**775**	792	800	820	831	856	860	876
Crude Oil *(bbls/d)*	**64,015**	66,549	**62,360**	62,691	67,043	64,990	64,789	65,097	69,781	70,287
NGLs *(bbls/d)*	**1,193**	1,199	**1,216**	1,162	1,201	1,126	1,147	1,189	1,262	1,422
Total *(MMcfe/d)* (1)	**1,180**	1,255	**1,156**	1,175	1,209	1,217	1,227	1,253	1,286	1,306

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

Produced Gas

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $89 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $414 million impact resulting from a 67 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $45 million impact resulting from a 7 percent decrease in natural gas production volumes. Produced gas volumes decreased in the third quarter of 2009 due to expected natural declines for the Shallow Gas key resource play and conventional properties partially offset by lower royalties;

partially offset by:

- Realized financial hedging gains of $283 million or $3.98 per Mcf in 2009 compared to losses of $87 million or $1.14 per Mcf in 2008.

The decrease in Canadian Plains natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials.

Canadian Plains natural gas production and mineral taxes of $3 million in 2009 decreased $11 million or 79 percent compared to 2008 primarily as a result of lower natural gas prices.

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

Canadian Plains natural gas operating expenses of $56 million in 2009 were $12 million or 27 percent higher compared to 2008 primarily as a result of higher long-term compensation costs due to the change in the EnCana share price and higher property tax and lease costs partially offset by the lower U.S./Canadian dollar exchange rate as well as lower repairs and maintenance and workover costs.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $312 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $1,065 million impact resulting from a 58 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $146 million impact resulting from a 7 percent decrease in natural gas production volumes. Produced gas volumes decreased in the nine months of 2009 due to expected natural declines for the Shallow Gas key resource play and conventional properties partially offset by lower royalties;

partially offset by:

- Realized financial hedging gains of $728 million or $3.38 per Mcf in 2009 compared to losses of $171 million or $0.73 per Mcf in 2008.

The decrease in Canadian Plains natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials.

Canadian Plains natural gas production and mineral taxes of $11 million in 2009 decreased $21 million or 66 percent compared to 2008 primarily as a result of lower natural gas prices.

Canadian Plains natural gas transportation and selling costs of $31 million in 2009 decreased $24 million or 44 percent compared to 2008 due to lower volumes and costs to eastern Canada and the U.S. as well as the lower U.S./Canadian dollar exchange rate.

Canadian Plains natural gas operating expenses of $158 million in 2009 were $33 million or 17 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, lower repairs and maintenance and workover costs partially offset by higher property tax and lease costs.

Crude Oil and NGLs

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $248 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $252 million impact resulting from a 41 percent decrease in crude oil prices and 54 percent decrease in NGLs prices, excluding financial hedges;
- A $43 million impact resulting from a decrease in average prices and volume of condensate used for blending with heavy oil; and
- A $9 million impact resulting from a 4 percent decrease in crude oil volumes partially offset by 6 percent increase in NGLs volumes. Production in 2009 from the Pelican Lake key resource play of 20,566 bbls/d was down 7 percent and from Suffield of 11,013 bbls/d was down 12 percent primarily due to natural declines. These were partially offset by lower royalties and a 10 percent increase in production at Weyburn, which averaged 14,947 bbls/d in 2009, mainly due to well optimizations;

partially offset by:

- Realized financial hedging gains on liquids of less than $1 million in 2009 compared to losses of $56 million or $9.28 per bbl in 2008.

Canadian Plains crude oil prices decreased 41 percent to $59.45 per bbl in 2009 from $101.33 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices and changes in the average differentials. Total realized financial hedging gains on crude oil for Canadian Plains were less than $1 million in 2009 compared to losses of approximately $55 million or $9.27 per bbl in 2008.

Canadian Plains NGLs prices decreased 54 percent to $44.88 per bbl in 2009 from $98.35 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Plains crude oil transportation and selling costs of $38 million in 2009 decreased $50 million or 57 percent compared to 2008 primarily due to a decrease in average prices and volume of condensate used for blending with heavy oil and the lower U.S./Canadian dollar exchange rate.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $848 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $806 million impact resulting from a 48 percent decrease in crude oil prices and 56 percent decrease in NGLs prices, excluding financial hedges;
- A $133 million impact resulting from a decrease in average prices and volume of condensate used for blending with heavy oil; and
- A $75 million impact resulting from a 4 percent decrease in crude oil volumes and 1 percent decrease in NGLs volumes. Production in 2009 from the Pelican Lake key resource play of 20,354 bbls/d was down 10 percent mainly due to natural declines and a scheduled facility turnaround. Suffield production of 12,314 bbls/d was down 7 percent primarily due to natural declines. These decreases were partially offset by lower royalties. In addition, production at Weyburn increased 14 percent to average 15,423 bbls/d in 2009 mainly due to lower royalties and well optimizations;

partially offset by:

- Realized financial hedging gains on liquids of $3 million or $0.15 per bbl in 2009 compared to losses of $163 million or $8.71 per bbl in 2008.

Canadian Plains crude oil prices decreased 48 percent to $48.44 per bbl in 2009 from $93.39 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices and changes in the average differentials. Total realized financial hedging gains on crude oil for Canadian Plains were approximately $3 million or $0.16 per bbl in 2009 compared to losses of approximately $160 million or $8.72 per bbl in 2008.

Canadian Plains NGLs prices decreased 56 percent to $39.44 per bbl in 2009 from $89.56 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Plains production and mineral taxes of $19 million in 2009 decreased $13 million or 41 percent compared to 2008 primarily as a result of lower crude oil prices.

Canadian Plains crude oil transportation and selling costs of $132 million in 2009 decreased $143 million or 52 percent compared to 2008 primarily due to a decrease in average prices and volume of condensate used for blending with heavy oil and the lower U.S./Canadian dollar exchange rate.

Canadian Plains crude oil operating costs of $161 million in 2009 were $30 million or 16 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate, reduced workover costs and lower chemicals costs partially offset by higher repairs and maintenance costs. NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

Capital Investment

Canadian Plains capital investment of $332 million during the nine months of 2009 was primarily focused on the Shallow Gas, Pelican Lake and Weyburn key resource plays. The $261 million decrease compared to 2008 was primarily due to lower drilling, completion and facility costs resulting from fewer wells drilled and tied in and the lower U.S./Canadian dollar exchange rate. Canadian Plains drilled 559 net wells in the nine months of 2009 compared to 1,034 net wells in 2008, consistent with the planned reduction in spending in 2009.

Depreciation, Depletion and Amortization

Total DD&A expenses of $992 million in the third quarter of 2009 decreased $103 million or 9 percent compared to 2008. Total DD&A expenses of $2,955 million in the nine months of 2009 decreased $272 million or 8 percent compared to 2008.

Upstream DD&A

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

Three Months Ended September 30, 2009 versus 2008

Upstream DD&A expenses of $910 million in the third quarter of 2009 decreased $103 million or 10 percent compared to 2008 due to:

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

Nine Months Ended September 30, 2009 versus 2008

Upstream DD&A expenses of $2,712 million in the nine months of 2009 decreased $258 million or 9 percent compared to 2008 due to:

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

Downstream DD&A

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

Downstream refining DD&A was $49 million in the third quarter of 2009 compared to $50 million in 2008 and $146 million in the nine months of 2009 compared to $138 million in 2008 as a result of a full year of depreciation on prior year capital additions, as well as accelerated depreciation on certain assets expected to be retired sooner than originally anticipated.

Market Optimization

Financial Results

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Revenues	**$ 381**	$ 840	**$ 1,239**	$ 2,112
Expenses				
Operating	**11**	8	**26**	27
Purchased product	**363**	811	**1,192**	2,046
Operating Cash Flow	**7**	21	**21**	39
Depreciation, depletion and amortization	**6**	4	**15**	12
Segment Income	**$ 1**	$ 17	**$ 6**	$ 27

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification that enhance the sale of EnCana's production.

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

Capital Investment

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

Corporate and Other

Financial Results

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Revenues	**$ (1,372)**	$ 3,057	**$ (2,352)**	$ 1,634
Expenses				
Operating	**11**	(3)	**40**	(11)
Depreciation, depletion and amortization	**27**	28	**82**	107
Segment Income (Loss)	**$ (1,410)**	$ 3,032	**$ (2,474)**	$ 1,538

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

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

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Revenues				
Natural Gas	**$ (1,391)**	$ 2,807	**$ (2,332)**	$ 1,486
Crude Oil	**18**	250	**(22)**	147
	(1,373)	3,057	**(2,354)**	1,633
Expenses	**11**	7	**37**	(6)
	(1,384)	3,050	**(2,391)**	1,639
Income Tax Expense (Recovery)	**(453)**	1,007	**(799)**	568
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ (931)**	$ 2,043	**$ (1,592)**	$ 1,071

Commodity price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gain or loss reflected in corporate revenues are the result of volatility between periods in the forward curve commodity price market and changes in the balance of unsettled contracts. Further information regarding financial instrument agreements can be found in Note 17 to the Interim Consolidated Financial Statements.

Consolidated Expenses

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Administrative	**$ 145**	$ 18	**$ 350**	$ 399
Interest, net	**155**	147	**388**	428
Accretion of asset retirement obligation	**20**	20	**56**	61
Foreign exchange (gain) loss, net	**(114)**	110	**(116)**	170
(Gain) loss on divestitures	**(1)**	(124)	**1**	(141)

Administrative expenses increased $127 million in the third quarter of 2009 compared to 2008 primarily due to higher long-term compensation expenses as a result of the change in the EnCana share price and a one time charge for settlement of a lawsuit. Further details regarding the legal settlement are available in the Legal Proceedings section of this MD&A. Administrative expenses decreased $49 million in the nine months of 2009 compared to 2008 as a result of the lower U.S./Canadian dollar exchange rate. In addition, 2008 expenses included higher costs related to the proposed corporate reorganization.

Net interest expense in the nine months of 2009 decreased $40 million from 2008 primarily as a result of lower average outstanding debt. Excluding the Cenovus Notes, EnCana's total long-term debt including current portion decreased $1,494 million to $8,163 million at September 30, 2009 compared to $9,657 million at September 30, 2008. EnCana's year-to-date weighted average interest rate on outstanding debt was 5.3 percent in 2009 compared to 5.4 percent in 2008.

The foreign exchange gain of $116 million in the nine months of 2009 is primarily due to the effects of the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada offset by the foreign exchange revaluation of the partnership contribution receivable, other foreign exchange gains and losses arising from the settlement of foreign currency transactions and the translation of EnCana's monetary assets and liabilities.

Income Tax

Total income tax expense in the nine months of 2009 was $384 million, which was $1,976 million lower than the same period in 2008 due to lower net earnings before income tax, particularly in the US where the statutory income tax rate is higher than in Canada.

Current income tax expense in the nine months of 2009 was $872 million, which is comparable to the same period in 2008. This reflects increased realized hedging gains offset by decreased operating Cash Flows, excluding realized hedging gains.

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

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

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

If the proposed Arrangement proceeds, it will result in an acceleration of future taxes for Canadian operations that will be recognized in the fourth quarter of 2009. The impact on 2009 current taxes is expected to be an increase of approximately $700 million. This is anticipated to be partially offset by a U.S. tax benefit which will accrue to EnCana in 2010 and subsequent years as a result of returning to independent producer status.

Capital Investment

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

Liquidity and Capital Resources

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Net cash from (used in)				
Operating activities	**$ 2,697**	$ 3,058	**$ 6,483**	$ 6,812
Investing activities	**(3,851)**	(2,326)	**(6,946)**	(5,896)
Financing activities	**2,194**	(881)	**1,445**	(837)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**6**	(7)	**11**	(10)
Increase (decrease) in cash and cash equivalents	**$ 1,046**	$ (156)	**$ 993**	$ 69

Operating Activities

Net cash from operating activities decreased $361 million in the third quarter of 2009 compared to 2008 and $329 million in the nine months of 2009 compared to 2008. Cash Flow was $2,079 million during the third quarter of 2009 compared to $2,809 million in 2008 and $6,176 million during the nine months of 2009 compared to $8,087 million in 2008. Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in other assets and liabilities and net changes in non-cash working capital, primarily from decreases in accounts receivable and accrued revenues and increases in income tax payable offset by decreases in accounts payable and accrued liabilities.

Excluding the impact of current risk management assets and liabilities, the Company had a working capital deficit of $323 million at September 30, 2009 compared to $463 million at September 30, 2008. As is typical in the oil and gas industry, there is a timing difference between cash receipts from sales transactions and payments of trade payables, which often results in a working capital deficit. EnCana anticipates that it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used for investing activities in the nine months of 2009 increased $1,050 million compared to the same period in 2008.

Net cash used for investing activities in the nine months of 2009 included restricted cash of $3,619 million that was placed into an escrow account pending release to Cenovus Energy Inc. once the Arrangement has become effective and all of the escrow conditions have been satisfied. Additional information on the restricted cash balance can be found in the Financing

Activities section of this MD&A. In addition, capital expenditures, including property acquisitions, decreased $2,341 million in the nine months of 2009 compared to 2008 and proceeds from divestitures increased $437 million in the nine months of 2009 compared to 2008. Reasons for these changes are discussed under the Net Capital Investment and Divisional Results sections of this MD&A.

Financing Activities

In conjunction with the proposed Arrangement, on September 18, 2009, EnCana's wholly owned subsidiary, Cenovus Energy Inc., completed a private offering of senior unsecured notes for an aggregate principal amount of $3,500 million issued in three tranches, which are exempt from the registration requirements of the U.S. Securities Act of 1933 under Rule 144A and Regulation S.

The debt securities have been assigned provisional ratings of "BBB+" with a "Stable" outlook by Standard and Poor's Ratings Services (“S&P”) and "A(low)" by DBRS Limited (“DBRS”), and "Baa2" with a "Stable" outlook by Moody's Investor Services, Inc. (“Moody's”). S&P's rating is contingent on completion of the Arrangement and DBRS expects to finalize its rating if the Arrangement proceeds as expected.

The notes are legal obligations of Cenovus Energy Inc. and have been disclosed on EnCana's Consolidated Balance Sheet as a separate long-term liability, net of financing costs. The net proceeds of the private offering were placed into an escrow account held by the escrow agent, The Bank of New York Mellon, pending the completion of the Arrangement, pursuant to the terms and conditions of an escrow and security agreement for the benefit of the note holders. The underwriters have deposited $3,468 million into the escrow account and Cenovus Energy Inc. has contributed $151 million into the escrow account so that, in aggregate, the total escrowed funds of $3,619 million will be sufficient to pay the special mandatory redemption price for the notes if the Arrangement does not proceed.

Pursuant to the terms and conditions of the escrow and security agreement, neither EnCana nor Cenovus Energy Inc., or any of their subsidiaries have any rights to, access to, control of, or dominion over, the escrowed funds before the completion of the Arrangement. All amounts in the escrow account will be released to Cenovus Energy Inc. by the escrow agent promptly after the escrow agent has been notified that the Arrangement has become effective and all of the escrow conditions have been satisfied. If the Arrangement does not proceed, the notes will be subject to a special mandatory redemption at a redemption price, payable from the amounts held in escrow, equal to 101 percent of the aggregate principal amount of the notes plus a penalty payment computed with reference to the expected accrued interest.

Additional information about the calculation of the special mandatory redemption price and other effects of the proposed Arrangement can be found in EnCana's Information Circular dated October 20, 2009. The cash in escrow has been disclosed as Restricted Cash on EnCana's Consolidated Balance Sheet and is not available for current use.

Upon completion of the Arrangement, Cenovus Energy Inc. has obtained commitments from a syndicate of banks to make available a C$2.0 billion three-year revolving credit facility and a C$500 million 364-day revolving credit facility.

Excluding the Cenovus Notes, net repayment of long-term debt in the nine months of 2009 was $1,145 million compared to net issuance of $310 million for the same period in 2008. Excluding the Cenovus Notes, EnCana’s total long-term debt including current portion was $8,163 million at September 30, 2009 compared to $9,657 million at September 30, 2008.

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

Net cash from financing activities in the nine months of 2009 also included $3,468 million of net proceeds from the private offering of Cenovus Notes described above.

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

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

EnCana has in place a shelf prospectus whereby it may issue from time to time up to $4.0 billion, or the equivalent in foreign currencies, of debt securities in the United States. At September 30, 2009, $3.5 billion of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions. The shelf prospectus was renewed in 2008 and expires in April 2010.

As at September 30, 2009, excluding the Cenovus credit facilities, EnCana had available unused capacity under shelf prospectuses for up to $5.4 billion.

As at September 30, 2009, excluding the Cenovus credit facilities, EnCana had available unused committed bank credit facilities in the amount of $4.3 billion. EnCana has in place a revolving bank credit facility for C$4.5 billion that remains committed through October 28, 2012. One of EnCana's U.S. subsidiaries has in place a revolving bank credit facility for $565 million that remains committed through February 28, 2013. Effective July 31, 2009, this credit facility was amended to remove Lehman Brothers Bank, FSB as a lender, which reduced the size of the credit facility from $600 million to $565 million.

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

EnCana maintains investment grade credit ratings on its senior unsecured debt. Following the proposed corporate reorganization announcement on September 10, 2009, S&P maintained a rating of "A-" and placed the Company on "CreditWatch" with negative implications, Moody's affirmed the rating of "Baa2" with a "Stable" outlook, and DBRS maintained a rating of "A (low)" which is "Under Review with Developing Implications". DBRS placed the rating "Under Review" following the May 11, 2008 announcement of the proposed Arrangement.

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

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. Dividend payments were $901 million in the nine months of 2009 and $899 million in the nine months of 2008. These dividends were funded by Cash Flow.

Financial Metrics

	September 30 2009	December 31 2008
Debt to Capitalization (1)(2)	**25%**	28%
Debt to Adjusted EBITDA (times) (2)(3)	**1.1**	0.7

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

Debt to Capitalization and Debt to Adjusted EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength. EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times.

Outstanding Share Data

(millions)	September 30 2009	December 31 2008
Common Shares outstanding, beginning of year	**750.4**	750.2
Common Shares issued under option plans	**0.3**	3.0
Common Shares issued from PSU Trust	**0.5**	-
Common Shares purchased	**-**	(2.8)
Common Shares outstanding, end of period	**751.2**	750.4
Weighted average Common Shares outstanding – diluted	**751.4**	751.8

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. There were no Preferred Shares outstanding as at September 30, 2009 and 2008.

Employees have been granted options to purchase Common Shares under various plans. At September 30, 2009, approximately 0.2 million options without Tandem Share Appreciation Rights ("TSARs") attached were outstanding, all of which are exercisable.

Stock options granted after December 31, 2003 have an associated TSAR attached, which gives employees the right to elect to receive a cash payment equal to the excess of the market price of EnCana's Common Shares over the exercise price of their stock option in exchange for surrendering their stock option. The exercise of a TSAR, for a cash payment, does not result in the issuance of any additional EnCana Common Shares, so has no dilutive effect. Historically, virtually all employees holding options with TSARs attached deciding to realize the value of their options have exercised their TSARs to receive a cash payment. At September 30, 2009, approximately 21.2 million options with TSARs attached were outstanding, of which 12.5 million are exercisable.

In 2007, 2008 and 2009 EnCana also granted Performance TSARs, which vest and expire under the same terms and service conditions as TSARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited. At September 30, 2009, approximately 18.7 million Performance TSARs were outstanding, of which 3.8 million are exercisable.

In 2008, EnCana granted Share Appreciation Rights ("SARs") and Performance SARs to certain employees, which entitle the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the grant price. Performance SARs are subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance SARs that do not vest when eligible are forfeited. At September 30, 2009, approximately 5.9 million SARs and Performance SARs were outstanding, of which 0.7 million are exercisable.

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

Contractual Obligations and Contingencies

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

Included in EnCana's total long-term debt principal obligations of $8,189 million at September 30, 2009, excluding the Cenovus Notes, are $423 million in obligations related to Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for the periods disclosed in the Liquidity and Capital Resources section of this MD&A. Further details regarding EnCana's long-term debt are described in Note 11 to the Interim Consolidated Financial Statements.

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

As at September 30, 2009, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 88 Bcf at a weighted average price of $4.26 per Mcf.

Leases

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

Variable Interest Entities ("VIEs")

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

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

Legal Proceedings

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

Discontinued Merchant Energy Operations

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws. All but one of these lawsuits has been settled prior to 2009, without admitting any liability in the lawsuits.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Company and WD have conditionally agreed to settle this lawsuit pending the successful negotiation and execution of a Settlement Agreement. Subsequent to September 30, 2009, the Settlement Agreement was fully executed, without admitting any liability in the lawsuit.

Accounting Policies and Estimates

New Accounting Standards Adopted

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

Recent Accounting Pronouncements

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information. EnCana's IFRS changeover plan also addresses the requirements of the entities that result from the proposed corporate reorganization as described in the Proposed Arrangement section in this MD&A.

The key elements of EnCana's changeover plan include:

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

The Company has completed analyzing accounting policy alternatives and designed process and system changes required for areas of impact, including first time adoption exemptions available. Information system changes expected to be implemented in early 2010 are currently being tested.

The significant areas of impact continue to include property, plant & equipment ("PP&E"), impairment testing, asset retirement obligation, stock-based compensation, employee benefit plans, and income taxes. The areas identified as being significant have the greatest potential impact to the Company's financial statements or the greatest risk in terms of complexity to implement.

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

In July 2009, the International Accounting Standards Board released additional exemptions for first-time adopters of IFRS. Included in the amendments is an exemption which permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) over reserves to the unit of account level upon transition to IFRS. This exemption would relieve the Company from retrospective application of IFRS for upstream PP&E. EnCana currently intends to adopt this exemption.

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

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

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

Non-controlling Interests
As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1602 "Non-controlling Interests", which establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Risk Management

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

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

EnCana takes a proactive approach in identifying and managing risks that can affect the Company. Mitigation of these risks include, but are not limited to, the use of financial instruments and physical contracts, credit policies, operational policies, maintaining adequate insurance, environmental and safety policies as well as policies and enforcement procedures that can affect EnCana's reputation. Further discussion regarding the specific risks and mitigation of these risks can be found in the December 31, 2008 Management's Discussion and Analysis and Note 17 to the Interim Consolidated Financial Statements.

Climate Change

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and other air pollutants. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. As these federal and regional programs are under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating and capital costs in order to comply with GHG emissions legislation. However, EnCana will continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

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

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' was applied to virtually all fossil fuels, including diesel, natural gas, coal, propane, and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate started at C$10 per tonne of carbon equivalent emissions, rising by C$5 per tonne a year for the next four years. The forecast cost of carbon associated with the British Columbia regulations is not material to EnCana at this time and is being actively managed.

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

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

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

EnCana's strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

1. Manage Existing Costs
   When regulations are implemented, a cost is placed on EnCana's emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption, and a focus on minimizing the Company's steam to oil ratio help to support and drive its focus on cost reduction.
2. Respond to Price Signals
   As regulatory regimes for GHGs develop in the jurisdictions where EnCana works, inevitably price signals begin to emerge. The Company has initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of its operations. The price of potential carbon reductions plays a role in the economics of the projects that are

implemented. In response to the anticipated price of carbon, EnCana is also attempting, where appropriate, to realize the associated value of its reduction projects.

3. Anticipate Future Carbon Constrained Scenarios
   EnCana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, the Company gains useful knowledge that allows it to explore different strategies for managing its emissions and costs. These scenarios influence EnCana's long range planning and its analyses on the implications of regulatory trends.

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

EnCana recognizes that there is a cost associated with carbon emissions. EnCana is confident that greenhouse gas regulations and the cost of carbon at various price levels have been adequately considered as part of its business planning and scenarios analysis. EnCana believes that the resource play strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's GHG emissions is available in the Corporate Responsibility Report that is available on the Company's website at www.encana.com.

Alberta's New Royalty Programs

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

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

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

Outlook

As discussed in the Proposed Arrangement section of this MD&A, the Company announced its plan to proceed with the split into two independent energy companies. EnCana expects to complete the reorganization on November 30, 2009 following a Shareholders' meeting to be held on November 25, 2009 to vote on the proposed Plan of Arrangement.

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

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that natural gas represents an abundant, secure, long-term supply of energy to meet North American needs.

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

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

EnCana's as well as EnCana's post arrangement and Cenovus's post arrangement results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Additional detail regarding the impact of these factors on 2009 results is available in the Corporate Guidance on the Company's website at www.encana.com. EnCana updated its Corporate Guidance on November 12, 2009 to reflect the impact on operations of expected conditions for 2009. EnCana's news release dated November 12, 2009 and financial statements are available on www.sedar.com.

Advisory

Forward-Looking Statements

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: the proposed Arrangement, the timing thereof and the expected future attributes following the Arrangement of the Company ("GasCo") and Cenovus Energy Inc. ("Cenovus"); projected natural gas and oil production levels for 2009; projections relating to the adequacy of the Company's provision for taxes; the expected impact of the Alberta Royalty Framework and Transitional Royalty Program; projections with respect to natural gas production from unconventional resource plays and in-situ oil resources including with respect to the Foster Creek and Christina Lake projects, the CORE project and planned expansions of the Company's downstream heavy oil processing capacity and the capital costs and expected timing of the same; projections relating to the volatility of natural gas and crude oil prices in 2009 and beyond and the reasons therefor; the Company's projected capital investment levels for 2009, the flexibility of capital spending plans and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's defence of lawsuits; the impact of the changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on the Company's operations and operating costs; the impact of Western Canada pipeline constraints and potential refinery disruptions on future Canadian crude oil prices; projections that the Company's Bankers' Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; the Company's continued compliance with financial covenants under its credit facilities; the Company's ability to pay its creditors, suppliers, commitments and fund its 2009 capital program and pay dividends to shareholders; the impact of the current business market conditions, including the economic recession and financial market turmoil on the Company's operations and expected results; the effect of the Company's risk mitigation policies, systems, processes and insurance program; the Company's expectations for future Debt to Capitalization and Debt to Adjusted EBITDA ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards, including IFRS, on the Company and its Consolidated Financial Statements; and projections that natural gas represents an abundant, secure, long-term supply of energy to meet North American needs. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions based upon EnCana's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; the ability of the Company and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining crude oil; risks associated with technology and the application thereof to the business of the Company; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate; the risk of 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. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law, EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Forward-looking information respecting anticipated 2009 cash flow, operating cash flow and pre-tax cash flow for EnCana is based upon achieving average production of oil and gas for 2009 of approximately 4.465 Bcfe/d (pro forma GasCo approximately 2.975 Bcfe/d and Cenovus approximately 1.484 Bcfe/d), actual commodity prices and U.S./Canadian dollar foreign exchange rate to September 30, 2009, and applicable forward curve estimates for commodity prices and U.S./Canadian dollar foreign exchange rate for October 1 to December 31, 2009 and an average number of outstanding shares for EnCana of approximately 750 million. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

EnCana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that EnCana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in EnCana's news release dated November 12, 2009, which is available on EnCana's website at www.encana.com and on SEDAR at www.sedar.com.

Oil and Gas Information

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

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

Resource Play
Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate.

Currency, Non-GAAP Measures and References to EnCana

All information included in this document and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

Non-GAAP Measures
Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Cash Flow per share – diluted, Free Cash Flow, Operating Earnings, Operating Earnings per share – diluted, Adjusted EBITDA, Debt, Net Debt and Capitalization and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in this document as these measures are discussed and presented.

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

Additional Information

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

Consolidated Statement of Earnings *(unaudited)*

($ millions, except per share amounts)		Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
Revenues, Net of Royalties	*(Note 5)*	**$ 3,881**	$ 10,849	**$ 12,251**	$ 23,705
Expenses	*(Note 5)*				
Production and mineral taxes		**29**	138	**122**	406
Transportation and selling		**355**	443	**969**	1,282
Operating		**510**	521	**1,575**	1,926
Purchased product		**1,747**	3,445	**4,341**	8,720
Depreciation, depletion and amortization		**992**	1,095	**2,955**	3,227
Administrative		**145**	18	**350**	399
Interest, net	*(Note 7)*	**155**	147	**388**	428
Accretion of asset retirement obligation	*(Note 12)*	**20**	20	**56**	61
Foreign exchange (gain) loss, net	*(Note 8)*	**(114)**	110	**(116)**	170
(Gain) loss on divestitures	*(Note 6)*	**(1)**	(124)	**1**	(141)
		3,838	5,813	**10,641**	16,478
Net Earnings Before Income Tax		**43**	5,036	**1,610**	7,227
Income tax expense	*(Note 9)*	**18**	1,483	**384**	2,360
Net Earnings		**$ 25**	$ 3,553	**$ 1,226**	$ 4,867
Net Earnings per Common Share	*(Note 16)*				
Basic		**$ 0.03**	$ 4.74	**$ 1.63**	$ 6.49
Diluted		**$ 0.03**	$ 4.73	**$ 1.63**	$ 6.47

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statement of Retained Earnings *(unaudited)*

($ millions)		Nine Months Ended September 30, 2009	2008
Retained Earnings, Beginning of Year		**$ 17,584**	$ 13,082
Net Earnings		**1,226**	4,867
Dividends on Common Shares		**(901)**	(899)
Charges for Normal Course Issuer Bid	*(Note 13)*	**-**	(243)
Retained Earnings, End of Period		**$ 17,909**	$ 16,807

Consolidated Statement of Comprehensive Income *(unaudited)*

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2009**	2008	**2009**	2008
Net Earnings	**$ 25**	$ 3,553	**$ 1,226**	$ 4,867
Other Comprehensive Income, Net of Tax				
Foreign Currency Translation Adjustment	**985**	(430)	**1,630**	(782)
Comprehensive Income	**$ 1,010**	$ 3,123	**$ 2,856**	$ 4,085

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

($ millions)	Nine Months Ended September 30, 2009	2008
Accumulated Other Comprehensive Income, Beginning of Year	**$ 833**	$ 3,063
Foreign Currency Translation Adjustment	**1,630**	(782)
Accumulated Other Comprehensive Income, End of Period	**$ 2,463**	$ 2,281

See accompanying Notes to Consolidated Financial Statements.

Consolidated Balance Sheet *(unaudited)*

($ millions)		As at September 30, 2009	As at December 31, 2008
Assets			
Current Assets			
Cash and cash equivalents		**$ 1,376**	$ 383
Accounts receivable and accrued revenues		**1,596**	1,568
Current portion of partnership contribution receivable		**325**	313
Risk management	*(Note 17)*	**586**	2,818
Inventories	*(Note 10)*	**727**	520
		4,610	5,602
Property, Plant and Equipment, net	*(Note 5)*	**38,481**	35,424
Restricted Cash	*(Note 4)*	**3,619**	-
Investments and Other Assets		**936**	727
Partnership Contribution Receivable		**2,589**	2,834
Risk Management	*(Note 17)*	**31**	234
Goodwill		**2,703**	2,426
	(Note 5)	**$ 52,969**	$ 47,247
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,947**	$ 2,871
Income tax payable		**880**	424
Current portion of partnership contribution payable		**320**	306
Risk management	*(Note 17)*	**12**	43
Current portion of long-term debt	*(Note 11)*	**200**	250
		4,359	3,894
Long-Term Debt	*(Note 11)*	**7,963**	8,755
Cenovus Notes	*(Note 4)*	**3,468**	-
Other Liabilities		**1,083**	576
Partnership Contribution Payable		**2,615**	2,857
Risk Management	*(Note 17)*	**90**	7
Asset Retirement Obligation	*(Note 12)*	**1,412**	1,265
Future Income Taxes		**7,020**	6,919
		28,010	24,273
Shareholders' Equity			
Share capital	*(Note 13)*	**4,581**	4,557
Paid in surplus	*(Note 13)*	**6**	-
Retained earnings		**17,909**	17,584
Accumulated other comprehensive income		**2,463**	833
Total Shareholders' Equity		**24,959**	22,974
		$ 52,969	$ 47,247

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows *(unaudited)*

($ millions)		Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
Operating Activities					
Net earnings		**$ 25**	$ 3,553	**$ 1,226**	$ 4,867
Depreciation, depletion and amortization		**992**	1,095	**2,955**	3,227
Future income taxes	*(Note 9)*	**(294)**	1,418	**(488)**	1,491
Cash tax on sale of assets		**-**	25	**-**	25
Unrealized (gain) loss on risk management	*(Note 17)*	**1,384**	(3,050)	**2,391**	(1,639)
Unrealized foreign exchange (gain) loss		**(100)**	84	**(149)**	149
Accretion of asset retirement obligation	*(Note 12)*	**20**	20	**56**	61
(Gain) loss on divestitures	*(Note 6)*	**(1)**	(124)	**1**	(141)
Other		**53**	(212)	**184**	47
Net change in other assets and liabilities		**10**	(19)	**33**	(283)
Net change in non-cash working capital		**608**	268	**274**	(992)
Cash From Operating Activities		**2,697**	3,058	**6,483**	6,812
Investing Activities					
Capital expenditures	*(Note 5)*	**(1,353)**	(2,466)	**(4,028)**	(6,369)
Proceeds from divestitures	*(Note 6)*	**977**	442	**1,030**	593
Cash tax on sale of assets	*(Note 6)*	**-**	(25)	**-**	(25)
Corporate acquisition	*(Note 6)*	**-**	-	**(24)**	-
Restricted cash	*(Note 4)*	**(3,619)**	-	**(3,619)**	-
Net change in investments and other		**80**	(157)	**(90)**	(166)
Net change in non-cash working capital		**64**	(120)	**(215)**	71
Cash (Used in) Investing Activities		**(3,851)**	(2,326)	**(6,946)**	(5,896)
Financing Activities					
Net issuance (repayment) of revolving long-term debt		**(726)**	(116)	**(1,391)**	251
Issuance of long-term debt	*(Note 11)*	**-**	-	**496**	723
Issuance of Cenovus Notes	*(Note 4)*	**3,468**	-	**3,468**	-
Repayment of long-term debt		**(250)**	(468)	**(250)**	(664)
Issuance of common shares	*(Note 13)*	**2**	2	**23**	78
Purchase of common shares	*(Note 13)*	**-**	-	**-**	(326)
Dividends on common shares		**(300)**	(299)	**(901)**	(899)
Cash From (Used in) Financing Activities		**2,194**	(881)	**1,445**	(837)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**6**	(7)	**11**	(10)
Increase (Decrease) in Cash and Cash Equivalents		**1,046**	(156)	**993**	69
Cash and Cash Equivalents, Beginning of Period		**330**	778	**383**	553
Cash and Cash Equivalents, End of Period		**$ 1,376**	$ 622	**$ 1,376**	$ 622

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

1. Basis of Presentation

The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles ("GAAP"). EnCana's operations are in the business of the exploration for, the development of, and the production and marketing of natural gas, crude oil and natural gas liquids ("NGLs"), refining operations and power generation operations.

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2008, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. Certain information and disclosures normally required to be included in the notes to the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, the interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2008.

2. Changes in Accounting Policies and Practices

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

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

3. Recent Accounting Pronouncements

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information. EnCana's IFRS changeover plan also addresses the requirements of the entities that result from the proposed corporate reorganization (See Note 4). The impact of IFRS on the Company's Consolidated Financial Statements is not reasonably determinable at this time.

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

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

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

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Proposed Corporate Reorganization

In May 2008, EnCana's Board of Directors unanimously approved a proposal to split EnCana into two independent energy companies – one a natural gas company and the other an integrated oil company. The proposed corporate reorganization (the “Arrangement”) was expected to close in early January 2009.

In October 2008, EnCana announced the proposed Arrangement would be delayed until the global debt and equity markets regained stability.

On September 10, 2009, EnCana's Board of Directors unanimously approved plans to proceed with the proposed Arrangement. The proposed Arrangement is expected to be implemented through a court approved Plan of Arrangement and is subject to shareholder and regulatory approvals. The reorganization would result in two publicly traded entities with the names of Cenovus Energy Inc. and EnCana Corporation. Under the Arrangement, EnCana Shareholders will receive one New EnCana Common Share and one Cenovus Energy Inc. Common Share in exchange for each EnCana Common Share held.

Subject to court and shareholder approval, EnCana expects to complete the reorganization on November 30, 2009 following a Shareholders' meeting to vote on the proposed Plan of Arrangement to be held on November 25, 2009.

In conjunction with the proposed Arrangement, on September 18, 2009, EnCana's wholly owned subsidiary, Cenovus Energy Inc., completed a private offering of senior unsecured notes for an aggregate principal amount of $3,500 million issued in three tranches, which are exempt from the registration requirements of the U.S. Securities Act of 1933 under Rule 144A and Regulation S.

	As at September 30, 2009
U.S. Unsecured Notes	
4.5% due September 15, 2014	**$ 800**
5.7% due October 15, 2019	**1,300**
6.75% due November 15, 2039	**1,400**
	3,500
Debt Discounts and Financing Costs	**(32)**
Cenovus Notes	**3,468**
Amounts on Deposit in Escrow	**151**
Restricted Cash	**$ 3,619**

The notes are legal obligations of Cenovus Energy Inc. and have been disclosed on EnCana's Consolidated Balance Sheet as a separate long-term liability, net of financing costs. The net proceeds of the private offering were placed into an escrow account held by the escrow agent, The Bank of New York Mellon, pending the completion of the Arrangement, pursuant to the terms and conditions of an escrow and security agreement for the benefit of the note holders. The underwriters have deposited $3,468 million into the escrow account and Cenovus Energy Inc. has contributed $151 million into the escrow account so that, in aggregate, the total escrowed funds of $3,619 million will be sufficient to pay the special mandatory redemption price for the notes if the Arrangement does not proceed.

Pursuant to the terms and conditions of the escrow and security agreement, neither EnCana nor Cenovus Energy Inc., or any of their subsidiaries have any rights to, access to, control of, or dominion over, the escrowed funds before the completion of the Arrangement. All amounts in the escrow account will be released to Cenovus Energy Inc. by the escrow agent promptly after the escrow agent has been notified that the Arrangement has become effective and all of the escrow conditions have been satisfied. If the Arrangement does not proceed, the notes will be subject to a special mandatory redemption at a redemption price, payable from the amounts held in escrow, equal to 101 percent of the aggregate principal amount of the notes plus a penalty payment computed with reference to the expected accrued interest.

Additional information about the calculation of the special mandatory redemption price and other effects of the proposed Arrangement can be found in EnCana's Information Circular dated October 20, 2009. The cash in escrow has been disclosed as Restricted Cash on EnCana's Consolidated Balance Sheet and is not available for current use.

Subject to the completion of the Arrangement, Cenovus Energy Inc. has obtained commitments from a syndicate of banks to make available a C$2.0 billion three-year revolving credit facility and a C$500 million 364-day revolving credit facility.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Segmented Information

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

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

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

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

- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.

- **Corporate and Other** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

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

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

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

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

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

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

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Segmented Information (continued)

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

Segment and Geographic Information

	Canada		USA		Downstream Refining	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 2,101**	$ 2,776	**$ 1,161**	$ 1,477	**$ 1,610**	$ 2,699
Expenses						
Production and mineral taxes	**12**	41	**17**	97	**-**	-
Transportation and selling	**216**	311	**139**	132	**-**	-
Operating	**289**	273	**100**	127	**99**	116
Purchased product	**(41)**	(45)	**-**	-	**1,425**	2,679
	1,625	2,196	**905**	1,121	**86**	(96)
Depreciation, depletion and amortization	**537**	578	**373**	435	**49**	50
Segment Income (Loss)	**$ 1,088**	$ 1,618	**$ 532**	$ 686	**$ 37**	$ (146)

	Market Optimization		Corporate & Other		Consolidated	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 381**	$ 840	**$ (1,372)**	$ 3,057	**$ 3,881**	$ 10,849
Expenses						
Production and mineral taxes	**-**	-	**-**	-	**29**	138
Transportation and selling	**-**	-	**-**	-	**355**	443
Operating	**11**	8	**11**	(3)	**510**	521
Purchased product	**363**	811	**-**	-	**1,747**	3,445
	7	21	**(1,383)**	3,060	**1,240**	6,302
Depreciation, depletion and amortization	**6**	4	**27**	28	**992**	1,095
Segment Income (Loss)	**$ 1**	$ 17	**$ (1,410)**	$ 3,032	**248**	5,207
Administrative					**145**	18
Interest, net					**155**	147
Accretion of asset retirement obligation					**20**	20
Foreign exchange (gain) loss, net					**(114)**	110
(Gain) loss on divestitures					**(1)**	(124)
					205	171
Net Earnings Before Income Tax					**43**	5,036
Income tax expense					**18**	1,483
Net Earnings					**$ 25**	$ 3,553

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Segmented Information (continued)

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

Product and Divisional Information

Canada Segment

	Canadian Plains		Canadian Foothills		Integrated Oil - Canada		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 875**	$ 1,213	**$ 849**	$ 1,168	**$ 377**	$ 395	**$ 2,101**	$ 2,776
Expenses								
Production and mineral taxes	**9**	27	**2**	14	**1**	-	**12**	41
Transportation and selling	**48**	106	**40**	57	**128**	148	**216**	311
Operating	**111**	96	**126**	120	**52**	57	**289**	273
Purchased product	**-**	-	**-**	-	**(41)**	(45)	**(41)**	(45)
Operating Cash Flow	**$ 707**	$ 984	**$ 681**	$ 977	**$ 237**	$ 235	**$ 1,625**	$ 2,196

Canadian Plains Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 487**	$ 576	**$ 385**	$ 633	**$ 3**	$ 4	**$ 875**	$ 1,213
Expenses								
Production and mineral taxes	**3**	14	**6**	13	**-**	-	**9**	27
Transportation and selling	**10**	18	**38**	88	**-**	-	**48**	106
Operating	**56**	44	**55**	51	**-**	1	**111**	96
Operating Cash Flow	**$ 418**	$ 500	**$ 286**	$ 481	**$ 3**	$ 3	**$ 707**	$ 984

Canadian Foothills Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 761**	$ 982	**$ 77**	$ 172	**$ 11**	$ 14	**$ 849**	$ 1,168
Expenses								
Production and mineral taxes	**2**	12	**-**	2	**-**	-	**2**	14
Transportation and selling	**38**	54	**2**	3	**-**	-	**40**	57
Operating	**118**	108	**5**	7	**3**	5	**126**	120
Operating Cash Flow	**$ 603**	$ 808	**$ 70**	$ 160	**$ 8**	$ 9	**$ 681**	$ 977

USA Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,084**	$ 1,263	**$ 53**	$ 124	**$ 24**	$ 90	**$ 1,161**	$ 1,477
Expenses								
Production and mineral taxes	**12**	86	**5**	11	**-**	-	**17**	97
Transportation and selling	**139**	132	**-**	-	**-**	-	**139**	132
Operating	**78**	59	**-**	-	**22**	68	**100**	127
Operating Cash Flow	**$ 855**	$ 986	**$ 48**	$ 113	**$ 2**	$ 22	**$ 905**	$ 1,121

Integrated Oil Division

	Oil *		Downstream Refining		Other *		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 345**	$ 362	**$ 1,610**	$ 2,699	**$ 32**	$ 33	**$ 1,987**	$ 3,094
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**1**	-	**1**	-
Transportation and selling	**120**	137	**-**	-	**8**	11	**128**	148
Operating	**45**	42	**99**	116	**7**	15	**151**	173
Purchased product	**-**	-	**1,425**	2,679	**(41)**	(45)	**1,384**	2,634
Operating Cash Flow	**$ 180**	$ 183	**$ 86**	$ (96)	**$ 57**	$ 52	**$ 323**	$ 139

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Segmented Information (continued)

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

Segment and Geographic Information

	Canada		USA		Downstream Refining	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 6,054**	$ 8,089	**$ 3,461**	$ 4,356	**$ 3,849**	$ 7,514
Expenses						
Production and mineral taxes	**44**	95	**78**	311	**-**	-
Transportation and selling	**582**	915	**387**	367	**-**	-
Operating	**866**	1,053	**314**	482	**329**	375
Purchased product	**(72)**	(126)	**-**	-	**3,221**	6,800
	4,634	6,152	**2,682**	3,196	**299**	339
Depreciation, depletion and amortization	**1,544**	1,717	**1,168**	1,253	**146**	138
Segment Income (Loss)	**$ 3,090**	$ 4,435	**$ 1,514**	$ 1,943	**$ 153**	$ 201

	Market Optimization		Corporate & Other		Consolidated	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,239**	$ 2,112	**$ (2,352)**	$ 1,634	**$ 12,251**	$ 23,705
Expenses						
Production and mineral taxes	**-**	-	**-**	-	**122**	406
Transportation and selling	**-**	-	**-**	-	**969**	1,282
Operating	**26**	27	**40**	(11)	**1,575**	1,926
Purchased product	**1,192**	2,046	**-**	-	**4,341**	8,720
	21	39	**(2,392)**	1,645	**5,244**	11,371
Depreciation, depletion and amortization	**15**	12	**82**	107	**2,955**	3,227
Segment Income (Loss)	**$ 6**	$ 27	**$ (2,474)**	$ 1,538	**2,289**	8,144
Administrative					**350**	399
Interest, net					**388**	428
Accretion of asset retirement obligation					**56**	61
Foreign exchange (gain) loss, net					**(116)**	170
(Gain) loss on divestitures					**1**	(141)
					679	917
Net Earnings Before Income Tax					**1,610**	7,227
Income tax expense					**384**	2,360
Net Earnings					**$ 1,226**	$ 4,867

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Segmented Information (continued)

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

Product and Divisional Information

Canada Segment

	Canadian Plains		Canadian Foothills		Integrated Oil - Canada		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 2,470**	$ 3,629	**$ 2,671**	$ 3,432	**$ 913**	$ 1,028	**$ 6,054**	$ 8,089
Expenses								
Production and mineral taxes	**30**	64	**13**	30	**1**	1	**44**	95
Transportation and selling	**163**	330	**115**	167	**304**	418	**582**	915
Operating	**322**	385	**389**	478	**155**	190	**866**	1,053
Purchased product	**-**	-	**-**	-	**(72)**	(126)	**(72)**	(126)
Operating Cash Flow	**$ 1,955**	$ 2,850	**$ 2,154**	$ 2,757	**$ 525**	$ 545	**$ 4,634**	$ 6,152

Canadian Plains Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,483**	$ 1,795	**$ 978**	$ 1,826	**$ 9**	$ 8	**$ 2,470**	$ 3,629
Expenses								
Production and mineral taxes	**11**	32	**19**	32	**-**	-	**30**	64
Transportation and selling	**31**	55	**132**	275	**-**	-	**163**	330
Operating	**158**	191	**161**	191	**3**	3	**322**	385
Operating Cash Flow	**$ 1,283**	$ 1,517	**$ 666**	$ 1,328	**$ 6**	$ 5	**$ 1,955**	$ 2,850

Canadian Foothills Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 2,432**	$ 2,891	**$ 208**	$ 494	**$ 31**	$ 47	**$ 2,671**	$ 3,432
Expenses								
Production and mineral taxes	**11**	26	**2**	4	**-**	-	**13**	30
Transportation and selling	**109**	158	**6**	9	**-**	-	**115**	167
Operating	**362**	432	**17**	30	**10**	16	**389**	478
Operating Cash Flow	**$ 1,950**	$ 2,275	**$ 183**	$ 451	**$ 21**	$ 31	**$ 2,154**	$ 2,757

USA Division

	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 3,246**	$ 3,754	**$ 132**	$ 353	**$ 83**	$ 249	**$ 3,461**	$ 4,356
Expenses								
Production and mineral taxes	**66**	280	**12**	31	**-**	-	**78**	311
Transportation and selling	**387**	367	**-**	-	**-**	-	**387**	367
Operating	**237**	266	**-**	-	**77**	216	**314**	482
Operating Cash Flow	**$ 2,556**	$ 2,841	**$ 120**	$ 322	**$ 6**	$ 33	**$ 2,682**	$ 3,196

Integrated Oil Division

	Oil *		Downstream Refining		Other *		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 785**	$ 898	**$ 3,849**	$ 7,514	**$ 128**	$ 130	**$ 4,762**	$ 8,542
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**1**	1	**1**	1
Transportation and selling	**286**	380	**-**	-	**18**	38	**304**	418
Operating	**123**	133	**329**	375	**32**	57	**484**	565
Purchased product	**-**	-	**3,221**	6,800	**(72)**	(126)	**3,149**	6,674
Operating Cash Flow	**$ 376**	$ 385	**$ 299**	$ 339	**$ 149**	$ 160	**$ 824**	$ 884

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Segmented Information (continued)

The following tables represent EnCana's and Cenovus Energy Inc.'s divisional information, post-Arrangement (See Note 4), excluding their respective share of the Market Optimization and Corporate and Other segments.

EnCana's divisions, post-Arrangement, will include Canadian Foothills and USA. Cenovus Energy Inc.'s divisions, post-Arrangement, will include Integrated Oil and Canadian Plains.

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

Divisional Information

	EnCana					
	Canadian Foothills		USA		Total	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 849**	$ 1,168	**$ 1,161**	$ 1,477	**$ 2,010**	$ 2,645
Expenses						
Production and mineral taxes	**2**	14	**17**	97	**19**	111
Transportation and selling	**40**	57	**139**	132	**179**	189
Operating	**126**	120	**100**	127	**226**	247
Operating Cash Flow	**$ 681**	$ 977	**$ 905**	$ 1,121	**$ 1,586**	$ 2,098

	Cenovus					
	Integrated Oil		Canadian Plains		Total	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,987**	$ 3,094	**$ 875**	$ 1,213	**$ 2,862**	$ 4,307
Expenses						
Production and mineral taxes	**1**	-	**9**	27	**10**	27
Transportation and selling	**128**	148	**48**	106	**176**	254
Operating	**151**	173	**111**	96	**262**	269
Purchased product	**1,384**	2,634	**-**	-	**1,384**	2,634
Operating Cash Flow	**$ 323**	$ 139	**$ 707**	$ 984	**$ 1,030**	$ 1,123

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

Divisional Information

	EnCana					
	Canadian Foothills		USA		Total	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 2,671**	$ 3,432	**$ 3,461**	$ 4,356	**$ 6,132**	$ 7,788
Expenses						
Production and mineral taxes	**13**	30	**78**	311	**91**	341
Transportation and selling	**115**	167	**387**	367	**502**	534
Operating	**389**	478	**314**	482	**703**	960
Operating Cash Flow	**$ 2,154**	$ 2,757	**$ 2,682**	$ 3,196	**$ 4,836**	$ 5,953

	Cenovus					
	Integrated Oil		Canadian Plains		Total	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 4,762**	$ 8,542	**$ 2,470**	$ 3,629	**$ 7,232**	$ 12,171
Expenses						
Production and mineral taxes	**1**	1	**30**	64	**31**	65
Transportation and selling	**304**	418	**163**	330	**467**	748
Operating	**484**	565	**322**	385	**806**	950
Purchased product	**3,149**	6,674	**-**	-	**3,149**	6,674
Operating Cash Flow	**$ 824**	$ 884	**$ 1,955**	$ 2,850	**$ 2,779**	$ 3,734

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Segmented Information (continued)

Capital Expenditures

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	**2009**	2008
Capital				
Canadian Plains	**$ 104**	$ 173	**$ 332**	$ 593
Canadian Foothills	**505**	473	**1,250**	1,836
Integrated Oil - Canada	**111**	142	**340**	494
Canada	**720**	788	**1,922**	2,923
USA	**346**	621	**1,271**	1,800
Downstream Refining	**266**	133	**695**	310
Market Optimization	**1**	4	**(2)**	11
Corporate & Other	**5**	42	**38**	111
	1,338	1,588	**3,924**	5,155
Acquisition Capital				
Canadian Plains	**-**	-	**1**	-
Canadian Foothills	**8**	28	**82**	120
Canada	**8**	28	**83**	120
USA	**7**	850	**21**	1,094
	15	878	**104**	1,214
Total	**$ 1,353**	$ 2,466	**$ 4,028**	$ 6,369

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

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Segmented Information (continued)

Property, Plant and Equipment and Total Assets by Segment

	Property, Plant and Equipment		Total Assets	
	As at		As at	
	September 30, 2009	December 31, 2008	**September 30, 2009**	December 31, 2008
Canada	**$ 19,206**	$ 17,082	**$ 25,829**	$ 23,419
USA	**13,588**	13,541	**14,649**	14,635
Downstream Refining	**4,598**	4,032	**5,407**	4,637
Market Optimization	**140**	140	**445**	429
Corporate & Other	**949**	629	**6,639**	4,127
Total	**$ 38,481**	$ 35,424	**$ 52,969**	$ 47,247

On February 9, 2007, EnCana announced that it had entered into a 25 year lease agreement with a third party developer for The Bow office project. As at September 30, 2009, Corporate and Other Property, Plant and Equipment and Total Assets includes EnCana's accrual to date of $545 million ($252 million at December 31, 2008) related to this office project as an asset under construction.

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre ("PFC") for the Deep Panuke project. As at September 30, 2009, Canada Property, Plant, and Equipment and Total Assets includes EnCana's accrual to date of $377 million ($199 million at December 31, 2008) related to this offshore facility as an asset under construction.

Corresponding liabilities for these projects are included in Other Liabilities in the Consolidated Balance Sheet. There is no effect on the Company's net earnings or cash flows related to the capitalization of The Bow office project or the Deep Panuke PFC.

6. Acquisitions and Divestitures

Acquisitions

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

Divestitures

Total year-to-date proceeds received on the sale of assets were $1,030 million (2008 - $593 million). The significant items are described below:

Canada and USA

In 2009, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of $957 million (2008 - $218 million) in Canadian Foothills and $70 million (2008 - $123 million) in the USA.

Corporate and Other

In September 2008, the Company completed the sale of its interests in Brazil for net proceeds of $164 million resulting in a gain on sale of $124 million. After recording income tax of $25 million, EnCana recorded an after-tax gain of $99 million.

7. Interest, Net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	**2009**	2008
Interest Expense - Long-Term Debt	**$ 125**	$ 142	**$ 366**	$ 426
Interest Expense - Other *	**72**	56	**161**	166
Interest Income *	**(42)**	(51)	**(139)**	(164)
	$ 155	$ 147	**$ 388**	$ 428

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

8. Foreign Exchange (Gain) Loss, Net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	**2009**	2008
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada *	**$ (485)**	$ 205	**$ (774)**	$ 370
Translation of U.S. dollar partnership contribution receivable issued from Canada *	**254**	(119)	**414**	(218)
Other Foreign Exchange (Gain) Loss on:				
Monetary revaluations and settlements	**117**	24	**244**	18
	$ (114)	$ 110	**$ (116)**	$ 170

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

9. Income Taxes

The provision for income taxes is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	**2009**	2008
Current				
Canada	**$ 238**	$ 40	**$ 678**	$ 446
United States	**75**	-	**189**	385
Other Countries	**(1)**	25	**5**	38
Total Current Tax	**312**	65	**872**	869
Future	**(294)**	1,418	**(488)**	1,491
	$ 18	$ 1,483	**$ 384**	$ 2,360

10. Inventories

	As at September 30, 2009	As at December 31, 2008
Product		
Canada	**$ 68**	$ 46
USA	**6**	8
Downstream Refining	**513**	323
Market Optimization	**126**	127
Parts and Supplies	**14**	16
	$ 727	$ 520

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. Long-Term Debt

	As at September 30, 2009	As at December 31, 2008
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 221**	$ 1,410
Unsecured notes	**1,166**	1,020
	1,387	2,430
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**202**	247
Unsecured notes *	**6,600**	6,350
	6,802	6,597
Increase in Value of Debt Acquired	**52**	49
Debt Discounts and Financing Costs	**(78)**	(71)
Current Portion of Long-Term Debt	**(200)**	(250)
	$ 7,963	$ 8,755

* Excluding Cenovus Notes (See Note 4).

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

12. Asset Retirement Obligation

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas assets and refining facilities:

	As at September 30, 2009	As at December 31, 2008
Asset Retirement Obligation, Beginning of Year	**$ 1,265**	$ 1,458
Liabilities Incurred	**19**	54
Liabilities Settled	**(44)**	(115)
Liabilities Divested	**(17)**	(38)
Change in Estimated Future Cash Flows	**(8)**	54
Accretion Expense	**56**	79
Foreign Currency Translation	**141**	(227)
Asset Retirement Obligation, End of Period	**$ 1,412**	$ 1,265

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. Share Capital

(millions)	**September 30, 2009**			December 31, 2008		
	Number		**Amount**	Number		Amount
Common Shares Outstanding, Beginning of Year	**750.4**	**$**	**4,557**	750.2	$	4,479
Common Shares Issued under Option Plans	**0.3**		**4**	3.0		80
Common Shares Issued from PSU Trust	**0.5**		**19**	-		-
Stock-Based Compensation	**-**		**1**	-		11
Common Shares Purchased	**-**		**-**	(2.8)		(13)
Common Shares Outstanding, End of Period	**751.2**	**$**	**4,581**	750.4	$	4,557

Performance Share Units ("PSUs")

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

Normal Course Issuer Bid

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

Stock Options

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

The following tables summarize the information related to options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSARs") attached to them at September 30, 2009. Information related to TSARs is included in Note 15.

	Stock Options *(millions)*	**Weighted Average Exercise Price *(C$)***
Outstanding, Beginning of Year	**0.5**	**11.62**
Exercised	**(0.3)**	**11.59**
Outstanding, End of Period	**0.2**	**11.84**
Exercisable, End of Period	**0.2**	**11.84**

	Outstanding & Exercisable Options		
Range of Exercise Price (C$)	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*
11.50 to 14.50	0.2	0.4	11.84

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. Capital Structure

The Company's capital structure consists of Shareholders' Equity plus Long-Term Debt, defined as the current and long-term portions of long-term debt. The Company's objectives when managing its capital structure are to:

i) maintain financial flexibility to preserve EnCana's access to capital markets and its ability to meet its financial obligations; and
ii) finance internally generated growth as well as potential acquisitions.

The Company monitors its capital structure and short-term financing requirements using non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward the Company's overall debt position as measures of the Company's overall financial strength.

EnCana targets a Debt to Capitalization ratio of less than 40 percent. At September 30, 2009, EnCana's Debt to Capitalization ratio was 25 percent (December 31, 2008 - 28 percent) calculated as follows:

	As at	
	September 30, 2009	December 31, 2008
Debt *	**$ 8,163**	$ 9,005
Total Shareholders' Equity	**24,959**	22,974
Total Capitalization	**$ 33,122**	$ 31,979
Debt to Capitalization ratio	**25%**	28%

* Excluding Cenovus Notes (See Note 4).

EnCana targets a Debt to Adjusted EBITDA of less than 2.0 times. At September 30, 2009, Debt to Adjusted EBITDA was 1.1x (December 31, 2008 - 0.7x) calculated on a trailing twelve-month basis as follows:

	As at	
	September 30, 2009	December 31, 2008
Debt *	**$ 8,163**	$ 9,005
Net Earnings	**$ 2,303**	$ 5,944
Add (deduct):		
Interest, net	**546**	586
Income tax expense	**657**	2,633
Depreciation, depletion and amortization	**3,951**	4,223
Accretion of asset retirement obligation	**74**	79
Foreign exchange (gain) loss, net	**137**	423
(Gain) loss on divestitures	**2**	(140)
Adjusted EBITDA	**$ 7,670**	$ 13,748
Debt to Adjusted EBITDA	**1.1x**	0.7x

* Excluding Cenovus Notes (See Note 4).

EnCana has a long-standing practice of maintaining capital discipline, managing its capital structure and adjusting its capital structure according to market conditions to maintain flexibility while achieving the objectives stated above. To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt or repay existing debt.

The Company's capital management objectives, evaluation measures and definitions have remained unchanged over the periods presented. EnCana is subject to certain financial covenants in its credit facility agreements and is in compliance with all financial covenants.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

15. Compensation Plans

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

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	**2009**	2008
Current Service Cost	**$ 4**	$ 4	**$ 11**	$ 12
Interest Cost	**5**	5	**15**	16
Expected Return on Plan Assets	**(3)**	(4)	**(10)**	(14)
Amortization of Net Actuarial Losses	**3**	1	**7**	3
Amortization of Past Service Costs	**-**	-	**1**	1
Amortization of Transitional Obligation	**-**	-	**1**	(1)
Expense for Defined Contribution Plan	**11**	10	**33**	30
Net Benefit Plan Expense	**$ 20**	$ 16	**$ 58**	$ 47

For the nine months ended September 30, 2009, contributions of $6 million have been made to the defined benefit pension plans (2008 - $8 million).

B) Tandem Share Appreciation Rights ("TSARs")

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

	Outstanding TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**19,411,939**	**53.97**
Granted	**3,973,660**	**55.35**
Exercised - SARs	**(1,802,205)**	**42.47**
Exercised - Options	**(53,084)**	**34.41**
Forfeited	**(373,317)**	**59.90**
Outstanding, End of Period	**21,156,993**	**55.16**
Exercisable, End of Period	**12,451,333**	**51.17**

For the period ended September 30, 2009, EnCana recorded compensation costs of $71 million related to the outstanding TSARs (2008 - $68 million).

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

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

	Outstanding Performance TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**12,979,725**	**63.13**
Granted	**7,751,720**	**55.31**
Exercised - SARs	**(128,300)**	**56.09**
Exercised - Options	**(980)**	**56.09**
Forfeited	**(1,929,541)**	**62.75**
Outstanding, End of Period	**18,672,624**	**59.97**
Exercisable, End of Period	**3,793,229**	**60.46**

For the period ended September 30, 2009, EnCana recorded compensation costs of $36 million related to the outstanding Performance TSARs (2008 - $42 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

15. Compensation Plans (continued)

D) Share Appreciation Rights ("SARs")

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

	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	1,285,065	72.13
Granted	1,116,220	55.42
Forfeited	(49,975)	66.87
Outstanding, End of Period	2,351,310	64.31
Exercisable, End of Period	359,368	72.99

For the period ended September 30, 2009, EnCana recorded compensation costs of $3 million related to the outstanding SARs (2008 - nil).

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

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

	Outstanding Performance SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	1,620,930	69.40
Granted	2,140,440	55.31
Forfeited	(241,082)	67.94
Outstanding, End of Period	3,520,288	60.93
Exercisable, End of Period	297,174	69.40

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

F) Deferred Share Units ("DSUs")

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

	Outstanding DSUs
Canadian Dollar Denominated	
Outstanding, Beginning of Year	656,841
Granted	73,989
Converted from HPR awards	46,884
Units, in Lieu of Dividends	18,740
Redeemed	(45,352)
Outstanding, End of Period	751,102

For the period ended September 30, 2009, EnCana recorded compensation costs of $8 million related to the outstanding DSUs (2008 - $7 million).

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. Per Share Amounts

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

(millions)	March 31, 2009	June 30, 2009	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Weighted Average Common Shares Outstanding - Basic	750.5	751.0	**751.2**	750.3	**750.9**	750.0
Effect of Dilutive Securities	0.9	0.4	**0.2**	1.0	**0.5**	2.0
Weighted Average Common Shares Outstanding - Diluted	751.4	751.4	**751.4**	751.3	**751.4**	752.0

17. Financial Instruments and Risk Management

EnCana's financial assets and liabilities include cash and cash equivalents, restricted cash, accounts receivable and accrued revenues, accounts payable and accrued liabilities, the partnership contribution receivable and payable, risk management assets and liabilities, long-term debt, and the Cenovus Notes. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows:

A) Fair Value of Financial Assets and Liabilities

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments.

The fair value of restricted cash approximates its carrying amount due the nature of the amounts held in escrow (See Note 4).

The fair values of the partnership contribution receivable and partnership contribution payable approximate their carrying amount due to the specific nature of these instruments in relation to the creation of the integrated oil joint venture. Further information about these notes is disclosed in Note 11 to the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2008.

Risk management assets and liabilities are recorded at their estimated fair value based on the mark-to-market method of accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost using the effective interest method of amortization. The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates expected to be available to the Company at period end.

The Cenovus Notes are carried at amortized cost using the effective interest method of amortization. The estimated fair values of the notes have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates expected to be available to the Company at period end.

The fair value of financial assets and liabilities were as follows:

	As at September 30, 2009 Carrying Amount	**As at September 30, 2009 Fair Value**	As at December 31, 2008 Carrying Amount	As at December 31, 2008 Fair Value
Financial Assets				
Held-for-Trading:				
Cash and cash equivalents	**$ 1,376**	**$ 1,376**	$ 383	$ 383
Restricted cash (See Note 4)	**3,619**	**3,619**	-	-
Risk management assets *	**617**	**617**	3,052	3,052
Loans and Receivables:				
Accounts receivable and accrued revenues	**1,596**	**1,596**	1,568	1,568
Partnership contribution receivable *	**2,914**	**2,914**	3,147	3,147
Financial Liabilities				
Held-for-Trading:				
Risk management liabilities *	**$ 102**	**$ 102**	$ 50	$ 50
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**2,947**	**2,947**	2,871	2,871
Long-term debt *	**8,163**	**8,868**	9,005	8,242
Cenovus notes (See Note 4)	**3,468**	**3,651**	-	-
Partnership contribution payable *	**2,935**	**2,935**	3,163	3,163

* Including current portion.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities

Net Risk Management Position

	As at September 30, 2009	As at December 31, 2008
Risk Management		
Current asset	**$ 586**	$ 2,818
Long-term asset	**31**	234
	617	3,052
Risk Management		
Current liability	**12**	43
Long-term liability	**90**	7
	102	50
Net Risk Management Asset (Liability)	**$ 515**	$ 3,002

Summary of Unrealized Risk Management Positions

	As at September 30, 2009			As at December 31, 2008		
	Risk Management			Risk Management		
	Asset	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Natural gas	**$ 590**	**$ 90**	**$ 500**	$ 2,941	$ 10	$ 2,931
Crude oil	**27**	**6**	**21**	92	40	52
Power	**-**	**6**	**(6)**	19	-	19
Total Fair Value	**$ 617**	**$ 102**	**$ 515**	$ 3,052	$ 50	$ 3,002

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

	As at September 30, 2009	As at December 31, 2008
Prices actively quoted	**$ 465**	$ 2,055
Prices sourced from observable data or market corroboration	**50**	947
Total Fair Value	**$ 515**	$ 3,002

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities (continued)

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

	Notional Volumes		Term	Average Price		Fair Value
Natural Gas Contracts						
Fixed Price Contracts						
NYMEX Fixed Price	1,983	MMcf/d	2009	7.24	US$/Mcf	$ 453
NYMEX Fixed Price	1,721	MMcf/d	2010	6.07	US$/Mcf	(8)
NYMEX Fixed Price	108	MMcf/d	2011	6.73	US$/Mcf	(3)
Purchased Options						
NYMEX Call	(61)	MMcf/d	2009	11.67	US$/Mcf	(3)
NYMEX Put	209	MMcf/d	2009	9.10	US$/Mcf	95
Basis Contracts						
Canada	80	MMcf/d	2009			-
United States	427	MMcf/d	2009			(14)
Canada and United States *			2010-2013			(33)
						487
Other Financial Positions **						2
Total Unrealized Gain on Financial Contracts						489
Premiums Paid on Unexpired Options						11
Natural Gas Fair Value Position						$ 500

* EnCana has entered into swaps to protect against widening natural gas price differentials between production areas, including Canada, the U.S. Rockies and Texas, and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

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

	Notional Volumes		Term	Average Price		Fair Value
Crude Oil Contracts						
Fixed Price Contracts						
WTI NYMEX Fixed Price	27,000	bbls/d	2010	76.89	US$/bbl	$ 24
Other Financial Positions *						(3)
Crude Oil Fair Value Position						$ 21

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

	Fair Value
Power Purchase Contracts	
Power Fair Value Position	$ (6)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities (continued)

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

	Realized Gain (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,362**	$ (389)	**$ 3,776**	$ (955)
Operating Expenses and Other	**(4)**	(2)	**(33)**	(2)
Gain (Loss) on Risk Management	**$ 1,358**	$ (391)	**$ 3,743**	$ (957)

	Unrealized Gain (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	**2009**	2008
Revenues, Net of Royalties	**$ (1,373)**	$ 3,057	**$ (2,354)**	$ 1,633
Operating Expenses and Other	**(11)**	(7)	**(37)**	6
Gain (Loss) on Risk Management	**$ (1,384)**	$ 3,050	**$ (2,391)**	$ 1,639

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

	2009		2008
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 2,892**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**1,352**	**$ 1,352**	$ 682
Foreign Exchange Gain (Loss) on Canadian Dollar Contracts	**3**	**-**	-
Fair Value of Contracts Realized During the Period	**(3,743)**	**(3,743)**	957
Fair Value of Contracts Outstanding	**$ 504**	**$ (2,391)**	$ 1,639
Premiums Paid on Unexpired Options	**11**		
Fair Value of Contracts and Premiums Paid, End of Period	**$ 515**		

Commodity Price Sensitivities

The following table summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. The Company has used a 10 percent variability to assess the potential impact of commodity price changes. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting net earnings as at September 30, 2009 as follows:

	10% Price Increase	10% Price Decrease
Natural gas price	$ (497)	$ 497
Crude oil price	(79)	79
Power price	10	(10)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Financial Instruments and Risk Management (continued)

C) Risks Associated with Financial Assets and Liabilities

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

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

Natural Gas - To partially mitigate the natural gas commodity price risk, the Company has entered into option contracts and swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points.

Crude Oil - The Company has partially mitigated its commodity price risk on crude oil and condensate supply with swaps which fix WTI NYMEX prices.

Power - The Company has in place two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

Credit Risk
Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Any foreign currency agreements entered into are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at September 30, 2009, approximately 93 percent of EnCana's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At September 30, 2009, EnCana had four counterparties whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the partnership contribution receivable is the total carrying value.

Liquidity Risk
Liquidity risk is the risk the Company will encounter difficulties in meeting a demand to fund its financial liabilities as they come due. The Company manages its liquidity risk through cash and debt management. As disclosed in Note 14, EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times to steward the Company's overall debt position.

In managing liquidity risk, the Company has access to a wide range of funding at competitive rates through commercial paper, capital markets and banks. As at September 30, 2009, excluding the Cenovus credit facilities as disclosed in Note 4, EnCana had available unused committed bank credit facilities in the amount of $4.3 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for $5.4 billion. The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Financial Instruments and Risk Management (continued)

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

EnCana maintains investment grade credit ratings on its senior unsecured debt. Following the proposed corporate reorganization announcement on September 10, 2009 (See Note 4), S&P maintained the rating of "A-" and placed the Company on "CreditWatch" with negative implications. Moody's affirmed the rating of "Baa2" with a "Stable" outlook and DBRS maintained the rating of "A (low)" which is "Under Review with Developing Implications". DBRS placed the rating "Under Review" following the May 11, 2008 announcement of the proposed Arrangement.

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

	Less Than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	$ 2,947	$ -	$ -	$ -	$ 2,947
Risk Management Liabilities	12	89	1	-	102
Long-Term Debt *	685	1,866	2,710	9,904	15,165
Cenovus Notes *	141	409	1,209	5,517	7,276
Partnership Contribution Payable *	489	978	978	1,222	3,667

* Principal and interest, including current portion.

Included in EnCana's total long-term debt obligations of $15,165 million at September 30, 2009, excluding the Cenovus Notes, are $423 million in principal obligations related to Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities, excluding the Cenovus credit facilities as described in Note 4, are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 - 5 Years. Further information on Long-term Debt is contained in Note 11.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As EnCana operates primarily in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on the Company's reported results. EnCana's functional currency is Canadian dollars, however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations are not separately identifiable.

To mitigate the exposure to the fluctuating U.S./Canadian exchange rate, EnCana maintains a mix of both U.S. dollar and Canadian dollar debt.

As disclosed in Note 8, EnCana's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of U.S. dollar debt issued from Canada and the translation of the U.S. dollar partnership contribution receivable issued from Canada. At September 30, 2009, excluding the Cenovus Notes, EnCana had $5,600 million in U.S. dollar debt issued from Canada ($5,350 million at December 31, 2008) and $2,914 million related to the U.S. dollar partnership contribution receivable ($3,147 million at December 31, 2008). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $25 million change in foreign exchange (gain) loss at September 30, 2009 (2008 - $20 million), excluding the Cenovus Notes.

Interest Rate Risk

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

At September 30, 2009, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to approximately $3 million (2008 - $15 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

18. Contingencies

Legal Proceedings

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

Discontinued Merchant Energy Operations

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws. All but one of these lawsuits has been settled prior to 2009, without admitting any liability in the lawsuits.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Company and WD have conditionally agreed to settle this lawsuit pending the successful negotiation and execution of a Settlement Agreement. Subsequent to September 30, 2009, the Settlement Agreement was fully executed, without admitting any liability in the lawsuit.

19. Reclassification

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

Supplemental Financial Information *(unaudited)*

Financial Statistics

($ millions, except per share amounts)		**2009**			2008				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Consolidated									
Cash Flow [1]	**6,176**	**2,079**	2,153	1,944	9,386	1,299	2,809	2,889	2,389
Per share - Basic	**8.22**	**2.77**	2.87	2.59	12.51	1.73	3.74	3.85	3.19
- Diluted	**8.22**	**2.77**	2.87	2.59	12.48	1.73	3.74	3.85	3.17
Net Earnings	**1,226**	**25**	239	962	5,944	1,077	3,553	1,221	93
Per share - Basic	**1.63**	**0.03**	0.32	1.28	7.92	1.44	4.74	1.63	0.12
- Diluted	**1.63**	**0.03**	0.32	1.28	7.91	1.43	4.73	1.63	0.12
Operating Earnings [2]	**2,640**	**775**	917	948	4,405	449	1,442	1,469	1,045
Per share - Diluted	**3.51**	**1.03**	1.22	1.26	5.86	0.60	1.92	1.96	1.39
Effective Tax Rates using									
Net Earnings	**23.9%**				30.7%				
Operating Earnings, excluding divestitures	**29.0%**				28.0%				
Canadian Statutory Rate	**29.2%**				29.7%				
Foreign Exchange Rates *(US$ per C$1)*									
Average	**0.855**	**0.911**	0.857	0.803	0.938	0.825	0.961	0.990	0.996
Period end	**0.933**	**0.933**	0.860	0.794	0.817	0.817	0.944	0.982	0.973
Cash Flow Information									
Cash from Operating Activities	**6,483**	**2,697**	1,955	1,831	8,855	2,043	3,058	1,996	1,758
Deduct (Add back):									
Net change in other assets and liabilities	**33**	**10**	9	14	(262)	21	(19)	(171)	(93)
Net change in non-cash working capital	**274**	**608**	(207)	(127)	(269)	723	268	(722)	(538)
Cash Flow [1]	**6,176**	**2,079**	2,153	1,944	9,386	1,299	2,809	2,889	2,389

(1) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.

(2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

	2009	2008
Financial Metrics		
Debt to Capitalization [1]	**25%**	28%
Debt to Adjusted EBITDA [1, 2]	**1.1x**	0.7x
Return on Capital Employed [1, 2]	**8%**	20%
Return on Common Equity [2]	**9%**	27%

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

Supplemental Financial Information *(unaudited)*

Financial Statistics (continued)

($ millions, except per share amounts)

Common Share Information	2009				2008				
	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*									
Period end	**751.2**	**751.2**	751.1	750.6	750.4	750.4	750.3	750.2	750.0
Average - Basic	**750.9**	**751.2**	751.0	750.5	750.1	750.3	750.3	750.2	749.5
Average - Diluted	**751.4**	**751.4**	751.4	751.4	751.8	751.3	751.3	751.3	753.0
Price Range *($ per share)*									
TSX - C$									
High	**65.71**	**64.29**	65.71	63.50	97.81	68.04	95.91	97.81	79.26
Low	**44.64**	**51.34**	50.33	44.64	41.36	41.36	63.84	76.41	59.95
Close	**62.00**	**62.00**	57.67	51.60	56.96	56.96	67.96	93.36	78.20
NYSE - US$									
High	**59.95**	**59.95**	58.34	53.81	99.36	64.19	94.41	99.36	79.75
Low	**35.46**	**44.01**	39.70	35.46	34.00	34.00	61.13	74.16	58.13
Close	**57.61**	**57.61**	49.47	40.61	46.48	46.48	65.73	90.93	75.75
Dividends Paid *($ per share)*	**1.20**	**0.40**	0.40	0.40	1.60	0.40	0.40	0.40	0.40
Share Volume Traded *(millions)*	**1,028.7**	**263.2**	323.8	441.7	1,893.7	614.9	547.7	376.4	354.7
Share Value Traded *(US$ millions weekly average)*	**1,264.4**	**1,046.3**	1,248.1	1,495.5	2,348.6	2,114.5	2,912.5	2,486.0	1,900.5

Net Capital Investment *($ millions, for the nine months ended September 30)*	2009	2008
Capital Investment		
Canada		
Canadian Plains	**$ 332**	$ 593
Canadian Foothills	**1,250**	1,836
Integrated Oil - Canada	**340**	494
USA	**1,271**	1,800
Downstream Refining	**695**	310
Market Optimization	**(2)**	11
Corporate & Other	**38**	111
Capital Investment	**3,924**	5,155
Acquisitions		
Property		
Canada		
Canadian Plains	**1**	-
Canadian Foothills	**82**	120
USA	**21**	1,094
Corporate		
Canada		
Canadian Foothills [(1)]	**24**	-
Divestitures		
Property		
Canada		
Canadian Plains	**2**	(39)
Canadian Foothills	**(957)**	(218)
Integrated Oil - Canada	**-**	(8)
USA	**(70)**	(123)
Corporate & Other	**(5)**	(41)
Corporate		
Corporate & Other [(2)]	**-**	(164)
Net Acquisition and Divestiture Activity	**(902)**	621
Net Capital Investment	**$ 3,022**	$ 5,776

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

(2) In 2008, the sale of interests in Brazil was completed on September 18, 2008.

Supplemental Financial Information *(unaudited)*

Operating Statistics - After Royalties

Production Volumes by Geographic Region	2009				2008				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*									
Canada	**2,119**	**2,027**	2,207	2,123	2,205	2,181	2,243	2,212	2,181
USA	**1,616**	**1,524**	1,581	1,746	1,633	1,677	1,674	1,629	1,552
	3,735	**3,551**	3,788	3,869	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids [1] *(bbls/d)*									
Canada	**125,190**	**128,937**	123,954	122,609	120,230	123,019	119,703	114,121	124,056
USA	**11,227**	**10,325**	11,699	11,671	13,350	12,831	13,853	13,482	13,232
	136,417	**139,262**	135,653	134,280	133,580	135,850	133,556	127,603	137,288
Total *(MMcfe/d)*									
Canada	**2,871**	**2,801**	2,951	2,859	2,926	2,919	2,961	2,897	2,926
USA	**1,683**	**1,586**	1,651	1,816	1,713	1,754	1,757	1,710	1,631
	4,554	**4,387**	4,602	4,675	4,639	4,673	4,718	4,607	4,557

(1) Natural gas liquids include condensate volumes.

Production Volumes	2009				2008				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*									
Canadian Plains	**789**	**775**	792	800	842	820	831	856	860
Canadian Foothills	**1,275**	**1,201**	1,343	1,281	1,300	1,302	1,351	1,289	1,256
USA	**1,616**	**1,524**	1,581	1,746	1,633	1,677	1,674	1,629	1,552
Integrated Oil - Other	**55**	**51**	72	42	63	59	61	67	65
Total Produced Gas	**3,735**	**3,551**	3,788	3,869	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids *(bbls/d)*									
Light and Medium Oil									
Canadian Plains	**31,264**	**30,676**	31,183	31,946	31,128	32,147	30,134	30,479	31,752
Canadian Foothills	**7,623**	**6,943**	7,800	8,140	8,473	8,437	8,217	8,376	8,867
Heavy Oil									
Canadian Plains	**32,751**	**31,684**	31,508	35,097	35,029	32,843	34,655	34,618	38,029
Integrated Oil - Foster Creek/Christina Lake	**40,190**	**45,051**	40,677	34,729	30,183	35,068	31,547	24,671	29,376
Integrated Oil - Other	**2,765**	**4,401**	1,800	2,069	2,729	2,133	2,273	3,009	3,514
Natural Gas Liquids [1]									
Canadian Plains	**1,193**	**1,216**	1,162	1,201	1,181	1,126	1,147	1,189	1,262
Canadian Foothills	**9,404**	**8,966**	9,824	9,427	11,507	11,265	11,730	11,779	11,256
USA	**11,227**	**10,325**	11,699	11,671	13,350	12,831	13,853	13,482	13,232
Total Oil and Natural Gas Liquids	**136,417**	**139,262**	135,653	134,280	133,580	135,850	133,556	127,603	137,288
Total *(MMcfe/d)*	**4,554**	**4,387**	4,602	4,675	4,639	4,673	4,718	4,607	4,557

(1) Natural gas liquids include condensate volumes.

Downstream Refining	2009				2008				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations [1]									
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**409**	**425**	404	398	423	434	412	437	408
Crude utilization *(%)*	**90%**	**94%**	89%	88%	93%	96%	91%	97%	90%
Refined products *(Mbbls/d)*	**433**	**451**	428	421	448	456	438	464	435

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

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2009				2008				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas - Canadian Plains *($/Mcf)*									
Price	**3.51**	**2.87**	3.23	4.42	7.77	5.65	8.67	9.50	7.19
Production and mineral taxes	**0.05**	**0.04**	0.07	0.05	0.12	0.06	0.17	0.17	0.06
Transportation and selling	**0.14**	**0.15**	0.14	0.15	0.23	0.21	0.24	0.22	0.25
Operating	**0.73**	**0.78**	0.71	0.71	0.78	0.65	0.59	0.96	0.93
Netback	**2.59**	**1.90**	2.31	3.51	6.64	4.73	7.67	8.15	5.95
Produced Gas - Canadian Foothills *($/Mcf)*									
Price	**3.57**	**2.92**	3.19	4.58	8.12	5.87	9.03	9.94	7.61
Production and mineral taxes	**0.03**	**0.02**	0.04	0.03	0.06	0.03	0.09	0.09	0.03
Transportation and selling	**0.31**	**0.35**	0.30	0.30	0.42	0.37	0.43	0.43	0.47
Operating	**1.05**	**1.09**	1.02	1.04	1.15	0.98	0.87	1.39	1.41
Netback	**2.18**	**1.46**	1.83	3.21	6.49	4.49	7.64	8.03	5.70
Produced Gas - Canada *($/Mcf)*									
Price	**3.54**	**2.89**	3.20	4.51	7.97	5.78	8.88	9.76	7.44
Production and mineral taxes	**0.04**	**0.03**	0.05	0.04	0.08	0.04	0.12	0.12	0.04
Transportation and selling	**0.25**	**0.26**	0.23	0.24	0.35	0.31	0.36	0.35	0.38
Operating	**0.93**	**0.96**	0.89	0.94	1.03	0.87	0.77	1.23	1.25
Netback	**2.32**	**1.64**	2.03	3.29	6.51	4.56	7.63	8.06	5.77
Produced Gas - USA *($/Mcf)*									
Price	**3.45**	**3.41**	3.01	3.88	7.89	5.01	8.54	9.93	8.19
Production and mineral taxes	**0.15**	**0.08**	0.08	0.27	0.56	0.35	0.56	0.72	0.62
Transportation and selling	**0.88**	**0.99**	0.87	0.78	0.84	0.87	0.86	0.81	0.81
Operating	**0.54**	**0.56**	0.54	0.51	0.59	0.56	0.38	0.71	0.71
Netback	**1.88**	**1.78**	1.52	2.32	5.90	3.23	6.74	7.69	6.05
Produced Gas - Total *($/Mcf)*									
Price	**3.50**	**3.11**	3.12	4.23	7.94	5.44	8.74	9.83	7.75
Production and mineral taxes	**0.09**	**0.05**	0.06	0.14	0.28	0.17	0.31	0.37	0.28
Transportation and selling	**0.52**	**0.58**	0.50	0.49	0.56	0.55	0.57	0.55	0.56
Operating	**0.76**	**0.78**	0.75	0.75	0.84	0.74	0.61	1.01	1.02
Netback	**2.13**	**1.70**	1.81	2.85	6.26	3.98	7.25	7.90	5.89
Natural Gas Liquids - Canadian Plains *($/bbl)*									
Price	**39.44**	**44.88**	38.36	34.86	78.91	45.13	98.35	96.34	75.09
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**-**	**-**	-	-	-	-	0.01	-	-
Netback	**39.44**	**44.88**	38.36	34.86	78.91	45.13	98.34	96.34	75.09
Natural Gas Liquids - Canadian Foothills *($/bbl)*									
Price	**40.92**	**47.08**	40.07	35.81	80.22	42.03	95.49	101.23	80.80
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**1.54**	**1.73**	1.70	1.19	1.33	1.33	1.20	1.73	1.04
Netback	**39.38**	**45.35**	38.37	34.62	78.89	40.70	94.29	99.50	79.76
Natural Gas Liquids - Canada *($/bbl)*									
Price	**40.75**	**46.82**	39.89	35.70	80.10	42.31	95.74	100.78	80.23
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**1.37**	**1.52**	1.52	1.06	1.21	1.21	1.10	1.57	0.94
Netback	**39.38**	**45.30**	38.37	34.64	78.89	41.10	94.64	99.21	79.29
Natural Gas Liquids - USA [1] *($/bbl)*									
Price	**43.05**	**55.60**	47.27	27.43	83.18	45.39	97.63	105.73	82.22
Production and mineral taxes	**3.89**	**5.12**	4.18	2.48	7.25	3.79	8.19	9.75	7.13
Transportation and selling	**-**	**-**	-	-	-	-	-	-	-
Netback	**39.16**	**50.48**	43.09	24.95	75.93	41.60	89.44	95.98	75.09
Natural Gas Liquids - Total *($/bbl)*									
Price	**41.93**	**51.24**	43.70	31.37	81.67	43.88	96.72	103.29	81.24
Production and mineral taxes	**2.00**	**2.58**	2.16	1.30	3.70	1.93	4.25	4.94	3.63
Transportation and selling	**0.67**	**0.76**	0.74	0.51	0.59	0.59	0.53	0.78	0.46
Netback	**39.26**	**47.90**	40.80	29.56	77.38	41.36	91.94	97.57	77.15
Crude Oil - Light and Medium - Canadian Plains *($/bbl)*									
Price	**51.37**	**61.76**	55.00	37.51	84.84	41.60	107.59	107.08	85.90
Production and mineral taxes	**2.27**	**2.26**	1.86	2.69	3.33	2.05	4.70	3.97	2.72
Transportation and selling	**0.91**	**0.76**	1.02	0.96	1.20	0.96	1.41	1.27	1.16
Operating	**9.69**	**10.22**	9.35	9.50	10.56	8.28	9.40	13.05	11.60
Netback	**38.50**	**48.52**	42.77	24.36	69.75	30.31	92.08	88.79	70.42

[1] The Natural Gas Liquids - USA netback is equivalent to the Total Liquids - USA netback.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2009				2008				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil - Light and Medium - Canadian Foothills *($/bbl)*									
Price	**49.52**	**59.46**	53.10	37.31	91.78	47.51	112.73	114.28	93.42
Production and mineral taxes	**1.06**	**1.11**	1.06	1.02	1.48	1.11	1.65	2.05	1.16
Transportation and selling	**0.79**	**0.99**	(0.72)	2.09	2.07	1.55	2.12	2.70	1.92
Operating	**8.28**	**6.96**	9.21	8.52	12.75	11.68	10.02	15.39	13.84
Netback	**39.39**	**50.40**	43.55	25.68	75.48	33.17	98.94	94.14	76.50
Crude Oil - Heavy - Canadian Plains *($/bbl)*									
Price	**45.66**	**57.30**	48.22	31.34	74.08	31.30	95.86	98.65	70.44
Production and mineral taxes	**(0.02)**	**(0.01)**	0.02	(0.07)	0.03	0.06	0.07	(0.10)	0.07
Transportation and selling	**1.21**	**1.10**	1.37	1.17	1.60	1.13	2.42	1.60	1.29
Operating	**8.72**	**8.74**	9.61	7.82	9.04	7.17	7.62	11.30	9.93
Netback	**35.75**	**47.47**	37.22	22.42	63.41	22.94	85.75	85.85	59.15
Crude Oil - Total - excluding Foster Creek/Christina Lake *($/bbl)*									
Price	**48.57**	**59.25**	51.80	34.49	80.31	37.20	102.66	103.40	78.82
Production and mineral taxes	**1.09**	**1.08**	0.96	1.22	1.56	1.02	2.16	1.81	1.28
Transportation and selling	**1.10**	**1.05**	1.04	1.21	1.52	1.13	2.00	1.61	1.36
Operating	**9.23**	**9.08**	9.78	8.83	10.43	8.28	8.99	13.00	11.39
Netback	**37.15**	**48.04**	40.02	23.23	66.80	26.77	89.51	86.98	64.79
Crude Oil - Heavy - Foster Creek/Christina Lake *($/bbl)*									
Price [(1)]	**45.41**	**57.12**	47.34	26.90	62.44	19.86	91.21	93.64	59.67
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**2.67**	**2.72**	2.93	2.29	2.36	2.04	2.10	2.77	2.72
Operating	**11.38**	**10.78**	10.51	13.28	15.53	10.73	15.53	21.41	16.62
Netback	**31.36**	**43.62**	33.90	11.33	44.55	7.09	73.58	69.46	40.33
Crude Oil - Total [(2)] *($/bbl)*									
Price	**47.47**	**58.45**	50.22	32.16	75.36	31.58	99.39	100.99	74.10
Production and mineral taxes	**0.71**	**0.68**	0.62	0.84	1.13	0.69	1.54	1.36	0.96
Transportation and selling	**1.64**	**1.67**	1.71	1.54	1.75	1.43	2.03	1.90	1.69
Operating	**9.97**	**9.72**	10.04	10.19	11.84	9.08	10.86	15.08	12.68
Netback	**35.15**	**46.38**	37.85	19.59	60.64	20.38	84.96	82.65	58.77
Total Liquids - Canada *($/bbl)*									
Price	**46.90**	**57.54**	49.31	32.48	75.85	32.63	98.99	100.97	74.69
Production and mineral taxes	**0.65**	**0.62**	0.57	0.77	1.01	0.62	1.37	1.20	0.86
Transportation and selling	**1.62**	**1.66**	1.69	1.50	1.70	1.41	1.93	1.86	1.62
Operating	**9.13**	**8.96**	9.16	9.29	10.57	8.19	9.68	13.34	11.30
Netback	**35.50**	**46.30**	37.89	20.92	62.57	22.41	86.01	84.57	60.91
Total Liquids *($/bbl)*									
Price	**46.58**	**57.40**	49.14	32.03	76.58	33.81	98.85	101.46	75.44
Production and mineral taxes	**0.92**	**0.95**	0.88	0.92	1.63	0.92	2.09	2.09	1.46
Transportation and selling	**1.49**	**1.54**	1.55	1.36	1.53	1.28	1.72	1.67	1.46
Operating	**8.38**	**8.30**	8.38	8.46	9.55	7.43	8.66	12.00	10.30
Netback	**35.79**	**46.61**	38.33	21.29	63.87	24.18	86.38	85.70	62.22
Total *($/Mcfe)*									
Price	**4.26**	**4.36**	4.02	4.42	8.77	5.48	10.04	11.02	8.61
Production and mineral taxes	**0.10**	**0.07**	0.08	0.15	0.28	0.17	0.32	0.37	0.28
Transportation and selling	**0.47**	**0.52**	0.46	0.44	0.50	0.49	0.53	0.50	0.50
Operating [(3)]	**0.87**	**0.90**	0.86	0.86	0.97	0.83	0.75	1.17	1.15
Netback	**2.82**	**2.87**	2.62	2.97	7.02	3.99	8.44	8.98	6.68

(1) 2008 price includes the impact of the write-down of condensate inventories to net realizable value (2008 - $4.26/bbl; Q4 2008 - $11.21/bbl; Q3 2008 - $3.07/bbl).
(2) The Crude Oil - Total netback is equivalent to the Crude Oil - Canada netback.
(3) 2009 year-to-date operating costs include costs related to long-term incentives of $0.02/Mcfe (2008 - $0.02/Mcfe).

Impact of Realized Financial Hedging

Natural Gas *($/Mcf)*	**3.68**	**4.20**	3.87	2.99	(0.02)	1.74	(0.80)	(1.29)	0.27
Liquids *($/bbl)*	**1.06**	**(0.01)**	1.09	2.21	(5.46)	2.35	(7.97)	(10.99)	(5.85)
Total *($/Mcfe)*	**3.05**	**3.39**	3.21	2.55	(0.17)	1.50	(0.89)	(1.38)	0.05

EnCana Corporation

FOR FURTHER INFORMATION:

EnCana Corporate Communications

Investor contact:

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

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

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

Media contact:

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

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

ENCANA™

energy for people