CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES STRONG QUARTERLY RESULTS AND 2007 BUDGET

In commenting on third quarter 2006 results, Canadian Natural's Chairman, Allan Markin stated, "The third quarter was significant for us as we entered into a timely acquisition of natural gas properties that greatly bolster and expand our natural gas portfolio. Confidence in our ability to deliver the Horizon Project and a confluence of industry events created a rare opportunity for Canadian Natural to make this strategic and attractively priced acquisition. We have also demonstrated capital discipline in our organic spending for 2007 in this highly inflationary environment. Our natural gas project inventories have never been stronger than they are today, and our reduced drilling activities for next year allow us to reduce exposure to supplier inflation. We remain very confident in our ability to deliver up to 5% natural gas volume growth and 10% overall production growth in years beyond 2007."

John Langille, Vice-Chairman, commented "The third quarter results show the continued strength of our asset base and the delivery of results in line with our expectations. For 2007 our disciplined allocation of capital will slow our organic growth profile slightly as we continue to maximize overall returns. Cost inflation, particularly in drilling and related services, is out of line with commodity prices. Our disciplined allocation of capital in 2007 will allow us to high grade development projects across the portfolio and specifically in our natural gas development, where cost inflation is the most prevalent."

Canadian Natural's President and Chief Operating Officer, Steve Laut, in commenting on the Company's quarter end stated, "Our asset base is strong and delivering long-term production growth and our project portfolio has never been stronger. For 2007 we expect cash flow in excess of conventional capital expenditures of approximately $2.7 billion. This significant free cash flow will be largely directed to the construction of Phase 1 of the Horizon Project, which itself will generate very significant free cash flow for decades to come. The ability of our base conventional business to generate significant free cash flow has enabled us to pursue strategic acquisitions as well as larger, more sustainable development projects and, in my opinion, it is one of the unique attributes of our large, balanced project portfolio."

HIGHLIGHTS

	Quarterly Results			Nine Month Results	
($ millions, except as noted)	**Q3/06**	Q2/06	Q3/05	**2006**	2005
Net earnings (loss)	**$ 1,116**	$ 1,038	$ 151	**$ 2,211**	$ (54)
per common share, basic	**$ 2.08**	$ 1.93	$ 0.28	**$ 4.12**	$ (0.10)
Adjusted net earnings from operations(1)	**$ 470**	$ 514	$ 593	**$ 1,252**	$ 1,433
per common share, basic	**$ 0.87**	$ 0.96	$ 1.10	**$ 2.33**	$ 2.67
Cash flow from operations(2)	**$ 1,313**	$ 1,287	$ 1,386	**$ 3,639**	$ 3,531
per common share, basic	**$ 2.44**	$ 2.40	$ 2.58	**$ 6.77**	$ 6.58
Capital expenditures, net of dispositions	**$ 1,661**	$ 1,558	$ 1,272	**$ 5,528**	$ 3,253
Debt to book capitalization(3)	**35%**	35%	32%	**35%**	32%
Daily production, before royalties					
Natural gas (mmcf/d)	**1,437**	1,475	1,423	**1,449**	1,444
Crude oil and NGLs (bbl/d)	**321,665**	338,852	334,724	**328,053**	304,036
Equivalent production (boe/d)	**561,152**	584,611	571,911	**569,590**	544,688

(1) Adjusted net earnings from operations is a non-GAAP term that the Company utilizes to evaluate its performance. The derivation of this item is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Cash flow from operations is a non-GAAP term that the Company considers key as it demonstrates its ability to fund capital reinvestment and debt repayment. The derivation of this item is discussed in the MD&A.

(3) Includes current portion of long-term debt.

- Quarterly cash flow of $1,313 million, a 2% increase over Q2/06 and 5% decrease from Q3/05. The increase from Q2/06 reflected higher sales revenues, primarily from strong Brent crude oil prices and production from the Primrose thermal heavy oil operations combined with higher heavy oil price realizations.

- Quarterly net earnings of $1,116 million, representing an 8% increase over Q2/06 and a seven-fold increase over Q3/05. Q3/06 net earnings included a pretax gain of $754 million for the unrealized risk management activities relating to crude oil and natural gas hedges.

- Quarterly adjusted net earnings from operations of $470 million, 9% lower than Q2/06 results and a 21% decrease from Q3/05 as a result of lower production and higher DD&A.

- Entered into an agreement relating to the acquisition of Anadarko Canada Corporation ("ACC"), a subsidiary of Anadarko Petroleum Corporation, for aggregate consideration of US$4.075 billion. ACC's land and production bases are located in Western Canada and are premium quality, concentrated natural gas weighted assets with strong netbacks and long reserve lives. The production, before royalties, from the working interests acquired by Canadian Natural, is approximately 358 million cubic feet per day of natural gas and 9,300 barrels per day of crude oil and NGLs. This acquisition is expected to close early in November 2006.

- Completed the quarter with a strong balance sheet with debt to book capitalization at 35% and debt to EBITDA at 1.0x.

- North America natural gas production in Q3/06 represented a decrease of 2% from Q2/06 and a 1% increase over Q3/05 despite reduced natural gas drilling activity in Q2/06 and Q3/06. ACC volumes are not included in this result.

- Crude oil production volumes in Q3/06 represented a decrease of 5% from Q2/06 and 4% from Q3/05 as a result of lower international production due to scheduled maintenance turnarounds in the North Sea and sand screen issues on four production wells at Baobab, Offshore West Africa.

- Completed a Q3/06 drilling program of 376 net wells, excluding stratigraphic test and service wells, with a 94% success ratio, reflecting Canadian Natural's strong, predictable, low-risk asset base.

- Maintained strong undeveloped conventional land base in Canada of 11.1 million net acres - a key asset in today's highly competitive industry. An additional 1.5 million net undeveloped acres will be acquired with the closing of the ACC acquisition.

- The Horizon Oil Sands Project ("Horizon Project"), remains slightly ahead of schedule and costs to date are as expected. Field construction itself is about one third complete and we are transitioning into the mechanical and piping stage. Cost pressures are causing cost estimates for certain isolated pieces of the project to be above target cost. However, such cost increases are not expected to, in aggregate, result in total costs of the project being materially different than the original target cost of $6.8 billion. Further, Canadian Natural remains on track for commissioning during the third quarter of 2008.

- Continued production improvements at Pelican Lake Field arising from new drilling activity and expansion of enhanced crude oil recovery program. Pelican Lake crude oil production averaged approximately 30,000 bbl/d during the quarter, up 21% or approximately 5,000 bbl/d from Q3/05. Production is expected to continue to increase in Q4/06 and throughout 2007.

- As part of the Company's ongoing commodity hedging program to reduce the risk of volatility in commodity price markets and to support the Company's cash flow for its capital expenditure program throughout the Horizon Project construction period, greater than 70% of expected 2007 crude oil and natural gas volumes have been price protected through puts, collars and physical contracts. These risk management instruments provide certainty of cash flow to the Company while in all cases, allowing the Company to participate in price increases beyond current levels.

- Declared a quarterly dividend of $0.075 per common share for the October 1, 2006 dividend payment.

- Determined 2007 Budget initiatives as follows:

  – Significant curtailment in conventional capital spending with 2007 capital expenditures of $3.1 billion, a 23% reduction compared to 2006 spending, excluding acquisitions and divestments. This includes $2.5 billion in North America, a reduction of $0.8 billion from 2006 levels, reflecting the drilling of 423 natural gas wells and 666 crude oil wells, and $0.6 billion internationally, a reduction of $0.2 billion, again from 2006 levels, to effect exploitation and development work in both the North Sea and Offshore West Africa. There is no change to capital allocated to the Horizon Project with $3.3 billion to be expended on the construction of the Horizon Project, including $0.5 billion relating to capitalized items as well as engineering and construction relating to Phases 2 and 3 of the Horizon Project.

  – Equivalent production target of 581 - 637 mboe/d before royalties, representing a midpoint increase of 5% from the midpoint of 2006 annual guidance. Natural gas production is targeted to increase by 9%, while crude oil production will increase by 2%.

  – Utilizing a 2007 planning price deck of US$65/bbl WTI and C$7.35/GJ AECO, cash flow is estimated to reach $5.6 billion to $6.0 billion. These parameters would result in a debt to book capitalization ratio of approximately 45% and debt to EBITDA of 1.6 times at the end of 2007.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities into core regions where it can dominate the land base and infrastructure. Undeveloped land is critical to the Company's ongoing growth and development within these core regions. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; namely natural gas, light, medium, and heavy crude oil and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Sep 30, 2006 (thousands of net acres)	Drilling activity nine months ended Sep 30, 2006 (net wells)
Canadian conventional		
Northeast British Columbia	**1,979**	**214**
Northwest Alberta	**1,421**	**138**
Northern Plains	**6,340**	**548**
Southern Plains	**755**	**102**
Southeast Saskatchewan	**83**	**65**
	10,578	**1,067**
In-situ Oil Sands	**410**	**226**
Horizon Oil Sands Project	**116**	**103**
United Kingdom North Sea	**332**	**7**
Offshore West Africa	**207**	**4**
	11,643	**1,407**

Drilling activity (number of wells)

	Nine Months Ended Sep 30			
	2006		2005	
	Gross	**Net**	Gross	Net
Crude oil	**471**	**426**	490	437
Natural gas	**774**	**581**	723	611
Dry	**102**	**91**	106	94
Subtotal	**1,347**	**1,098**	1,319	1,142
Stratigraphic test / service wells	**310**	**309**	217	215
Total	**1,657**	**1,407**	1,536	1,357
Success rate (excluding stratigraphic test / service wells)		**92%**		92%

North America natural gas	Quarterly Results			Nine Month Results	
	Q3/06	Q2/06	Q3/05	**2006**	2005
Natural gas production (mmcf/d)	**1,416**	1,448	1,400	**1,425**	1,421
Net wells targeting natural gas	**111**	48	226	**658**	680
Net successful wells drilled	**98**	43	213	**581**	611
Success rate	**88%**	90%	94%	**88%**	90%

- As a result of the strategic move to reduce natural gas drilling, which saw a 51% decrease in Q3/06 drilling compared to Q3/05, Q3/06 saw North America natural gas production decrease 2% over Q2/06. Despite drilling cutbacks in Q2/06 and Q3/06 compared to the prior year, North America natural gas production increased 1% over Q3/05 reflecting the high quality asset base and positive results from the 2006 winter drilling program.

- High drilling success rates reflect Canadian Natural's low-risk exploitation approach and high quality land base. The Q3/06 drilling program represented an active program across the Company's core regions. In Northeast British Columbia 6 net wells targeting natural gas were drilled, while in Northwest Alberta 28 net wells were drilled, including 9 Cardium targets. In Northern and Southern Plains, a total of 9 net coal bed methane, 20 net shallow natural gas and 48 net conventional natural gas wells were targeted.

- Planned drilling activity for Q4/06 includes 82 wells targeting natural gas.

North America crude oil and NGLs	Quarterly Results			Nine Month Results	
	Q3/06	Q2/06	Q3/05	**2006**	2005
Crude oil and NGLs production (bbl/d)	**233,440**	234,780	231,260	**230,430**	218,774
Net wells targeting crude oil	**263**	78	184	**431**	451
Net successful wells drilled	**253**	76	175	**417**	427
Success rate	**96%**	97%	95%	**97%**	95%

- In contrast to natural gas, the crude oil program utilizes fewer third party services and has experienced lower cost inflation while receiving higher wellhead pricing. As such, the revised 2006 second half crude oil drilling program reflects increased drilling of 43% at Pelican Lake and 28% for light crude oil, while heavy crude oil drilling remains unchanged due to the lack of availability of slant drilling rigs in the basin. In Q4/06, the Company has contracted two long-term slant drilling rigs to ensure availability of these specialized rigs on a go forward basis to execute the long-term drilling of heavy crude oil. Due to the timing of crude oil production profiles, the benefit of the ramped drilling program during the second half of the year will not be fully realized until mid-2007.

- Q3/06 North America crude oil and NGLs production decreased slightly over Q2/06 and increased 1% over Q3/05. This performance reflected continued success at the Primrose thermal crude oil project, which will see new pads moving from the steaming cycle to the production cycle in Q4/06, and continued production improvements at Pelican Lake.

- During Q3/06, drilling activity included 126 net wells targeting heavy crude oil, 46 net wells targeting Pelican Lake crude oil, 17 net wells targeting Thermal crude oil and 74 net wells targeting light crude oil. The majority of the wells were drilled in the Northern Plains core region. Production from this crude oil drilling program will be reflected in our Q4/06 and Q1/07 results.

- The Primrose East expansion program continues through the regulatory phase and, when approved, will see the expansion of the crude oil processing facility from 80,000 bbl/d to 120,000 bbl/d, as well as the construction of a steam generation plant and new pad drilling that will add production gains targeted at 40,000 bbl/d in 2009. Primrose East is the second phase of the 300,000 bbl/d conventional expansion plans identified for unlocking the value from Canadian Natural's thermal crude oil resource base. Detailed engineering and procurement are underway. The Company anticipates regulatory approval for Primrose East in Q1/07, drilling and construction to begin in Q2/07, and first production in 2009.

- At Pelican Lake, the development of land acreage and secondary recovery implementation projects continued as planned, with 46 horizontal producing wells drilled and conversion of 12 production wells to injection wells (2 for water and 10 for polymer injection) in Q3/06. During the quarter another 4 production wells were shut in for polymer conversion which have since been converted. Early results from the polymer flood pilot continue to be positive and four polymer skid installations were implemented in Q3/06, results will continue to be monitored. During the remainder of 2006, the Company plans to drill an additional 44 wells at Pelican Lake. Production increased slightly in Q3/06 from Q2/06 and production gains are anticipated to continue in Q4/06 and throughout 2007.

- Planned drilling activity for Q4/06 includes 224 net crude oil wells.

Canadian Natural Upgrader Project

Originally announced in the fall of 2005, the Company remains on track with its plans to design, construct and operate a heavy crude oil upgrader to process a portion of its conventional heavy and thermal heavy crude oil production. The Scoping Study for the Canadian Natural Upgrader continued on schedule during Q3/06. The terms of reference for this study will evaluate end product alternatives, location, technology, gasification and integration with existing assets. Recommendations are expected in the second half of 2007 and represent the first stage of front end loading for the project. This is the same disciplined approach utilized in the Horizon Project. Following this Study, the Design Basis Memorandum and Engineering Design Specification will be completed prior to construction and sanctioning of the project by the Board of Directors.

This upgrader will enable the Company to unlock significant shareholder value through the development and upgrading of over 3 billion barrels of thermal in-situ oil sands resources over the next 15 years. The project is forecast to be undertaken in two phases, with the first phase targeting upgrading capacity of 125,000 bbl/d of synthetic crude oil ("SCO") currently targeted to start up in 2013.

International

The Company operates in the North Sea and Offshore West Africa where production of lighter quality crude oil is targeted, but natural gas may be produced in association with crude oil production.

	Quarterly Results			Nine Month Results	
	Q3/06	Q2/06	Q3/05	**2006**	2005
Crude oil production (bbl/d)					
North Sea	**53,988**	63,703	73,543	**59,473**	69,198
Offshore West Africa	**34,237**	40,369	29,921	**38,150**	16,064
Natural gas production (mmcf/d)					
North Sea	**11**	17	18	**15**	19
Offshore West Africa	**10**	10	5	**9**	4
Net wells targeting crude oil	**2.2**	2.8	4.3	**9.2**	11.4
Net successful wells drilled	**2.2**	2.8	4.3	**9.2**	10.0
Success rate	**100%**	100%	100%	**100%**	88%

North Sea

- Canadian Natural continues to execute its exploitation strategy in the North Sea. The first stage of this exploitation program is based upon optimizing existing facilities and waterfloods. Canadian Natural continues to apply this first stage of exploitation on its holdings in the North Sea. The second stage of exploitation incorporates more near pool development and exploration in order to maximize utilization of the common facilities and ultimately extend all fields' economic lives. In 2006 and beyond, increasing emphasis on this type of work is evidenced by the ongoing development at the Columba Terraces and the Lyell Field.

- During Q3/06, 1.0 net well was drilled with an additional 1.0 net well drilling over quarter end. Production levels during the quarter were in line with expectations, although down from the previous quarter, reflecting planned maintenance shutdowns at Ninian, T-Block and B-Block. Production at Banff was also curtailed during September to allow compression upgrade work to be carried out on the Floating Production Storage and Offtake vessel ("FPSO"). This work, which will increase gas compression capacity resulting in an associated production uplift of 3,500 bbl/d net to Canadian Natural, was completed on budget and ahead of schedule.

- Plans for the further development of the Lyell Field progressed. The project entails drilling four net wells and working over two existing net wells, commencing in Q4/06. During Q3/06, a new subsea manifold was installed and the drilling rig was moved into place to commence drilling.

Offshore West Africa

- During Q3/06, 1.2 net wells were drilled with an additional 0.6 net wells drilling over quarter end.

- At the Espoir Field, crude oil production averaged approximately 18,800 bbl/d net to Canadian Natural during Q3/06, following the successful infill drilling program completed on time and on budget during Q2/06. A second production well was brought on stream in Q3/06, with further wells to be delivered in 2007. Current West Espoir production is 6,300 boe/d (field gross) and continues to ramp towards peak production of 13,500 boe/d targeted for mid 2007.

- Net production at Baobab averaged approximately 15,000 bbl/d during the quarter, reflecting the shut-in of production from 4 of 10 production wells throughout the quarter, due to the limitations resulting from sand screen effectiveness. This has resulted in approximately 12,000 bbl/d of reduced production capacity at the field. Modifications to the FPSO to allow for sand handling are being engineered. Canadian Natural is currently investigating the rig market to identify suitable availability to proceed to the second phase of the field development, including potentially redrilling the wells that are currently experiencing production limitations due to the amount of sand included with production.

- In Gabon, evaluation of key tenders continued on the Olowi Field development, together with engineering studies and pre-project planning are scheduled for the remainder of 2006 and 2007. The development plan is predicated on a one year capital deferral of the project and currently comprises an FPSO and four drilling towers with production targeted for 2009, and an anticipated plateau of 20,000 bbl/d.

Horizon Project

- Phase 1 of the Horizon Project continues slightly ahead of schedule with first production of 110,000 bbl/d of light, sweet SCO is targeted to commence in the third quarter of 2008.

- Total production levels of 232,000 bbl/d are targeted for 2012, following completion of two further phases of construction. The Company is currently conducting the EDS stage of engineering on the next phase (Phase 2) and in conjunction with that, is evaluating the opportunity to combine the next two phases (Phase 2 and Phase 3).

- The progress on major milestones, a key component in achieving critical path success, is slightly ahead of schedule and safety performance also remained ahead of target.

- During Q3/06, the Company awarded a further C$400 million of contracts, including several that were previously deferred in order to optimize pricing. This brings the total awarded contracts to C$4.8 billion. To date, over 640 modules and oversized loads are on site and over half of them have been installed. Additionally, all major plants have been passed through hazard/operability engineering review without requiring major scope change, providing even greater cost certainty. The construction is at a point where the critical foundations are complete and the site is transitioning as steel is erected, modules are placed and equipment is set.

- Canadian Natural continues to effectively execute well defined strategies and at this point in time for the work done to date (engineering, procurement and construction), which translates to a 47% overall project completion level, the Company is at the target cost forecast. Field construction itself is about one third complete and transitioning into the mechanical and piping stage is underway where new challenges will be faced, including ongoing cost pressures on non-issued contracts, productivity on the job site and usage of overtime.

- The Company has now entered into the majority of the construction contracts and as the last 53% of the overall project is undertaken, the aforementioned challenges and associated cost pressures are causing cost estimates for certain isolated pieces of the project to be above target cost. However, such cost increases are not expected to, in aggregate, result in total costs of the project being materially different than the original target cost of $6.8 billion. Further, Canadian Natural remains on track for commissioning during the third quarter of 2008.
- The quarterly update for the project is as follows:

Project status summary	**Sep 30, 2006**		Dec 31, 2006
	Actual	Plan	Plan
Phase 1 - Work progress (cumulative)	**47%**	44%	55%
Phase 1 - Construction capital spending (cumulative)*	**48%**	49%	58%

** Relates to overall Phase 1 project capital of $6.8 billion*

Accomplished During the Third Quarter of 2006

Detailed Engineering

- Completed in excess of 90% of overall detailed engineering model reviews in all areas, reducing potential for scope changes.
- Completed 90% of the 3-D model reviews.

Procurement

- Awarded in excess of C$400 million of contracts and purchase orders in the quarter, bringing awards-to-date to over C$4.8 billion, with a further C$200 million in various stages of the tender process.
- Awarded several key mechanical contracts and ordered mine shovels.

Modularization

- To date, in excess of 640 oversized loads, or 38% of Phase 1 totals, have been transported to site. Winter freeze up will enable transportation of ultra heavy loads similar to last winter.

Construction

- Completed approximately 33% of the construction effort.
- Set 295 piperack modules for total progress of 63% complete.
- Received and installed the first seven Inclined Plate Separator (“IPS”) units in Froth Treatment.
- Mine Overburden Administration and Maintenance Facility were completed and occupied.
- Completed site preparation and underground facilities.
- Camp 1 occupancy at 92%, Camp 2 occupancy at 33% and Camp 3 construction significantly complete.
- Commenced Tar River Diversion and Raw Water Pond construction project.

Milestones for the Fourth Quarter of 2006

- Completion and occupation of the Bitumen Production Administration building.
- Camp 3 ready for occupancy.
- Complete construction of Mechanically Stabilized Earth Shear Wall in the Ore Preparation Plant.
- Commence installation of Primary Upgrading large bore piping.
- Mobilize R1 & R2 pump house contractor for piping corridors.
- Start Floatation Cell and Pump Box installation for Extraction.

MARKETING

	Quarterly Results			Nine Months Results	
	Q3/06	Q2/06	Q3/05	**2006**	2005
Crude oil and NGLs pricing					
WTI[1] benchmark price (US$/bbl)	**$ 70.55**	$ 70.70	$ 63.17	**$ 68.29**	$ 55.45
Lloyd Blend Heavy oil differential from WTI (%)	**27%**	25%	30%	**32%**	36%
Corporate average pricing before risk management (C$/bbl)	**$ 62.55**	$ 60.05	$ 57.35	**$ 55.91**	$ 47.04
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 5.72**	$ 5.95	$ 7.73	**$ 6.82**	$ 7.03
Corporate average pricing before risk management (C$/mcf)	**$ 5.83**	$ 6.16	$ 8.61	**$ 6.75**	$ 7.53

(1) Refers to West Texas Intermediate crude oil barrel priced at Cushing, Oklahoma.

- Heavy crude oil differentials remained seasonally strong in Q3/06 averaging 27% of WTI, as a result of the summer paving season and the benefit from pipeline reversals during 2006, which now transport Canadian heavy crude oil to the US Gulf Coast. The Company has committed to 25 mbbl/d of new pipeline capacity on the reversal of the Pegasus Pipeline which carries heavy crude oil from the terminus of the current pipeline sales lines at Patoka, Illinois to the east Texas refining complex near Nederland. Canadian Natural also continues to work with various industry groups and strategic partners to find new markets for Western Canadian heavy crude oil in order to mitigate the impact of supply and demand shocks on the heavy crude oil market in North America. The Company expects a widening of this differential to the mid-30% range in the fourth quarter due to normal seasonal factors.

- During the quarter the Company, to provide certainty on a portion of its heavy crude oil differentials, entered into Maya-based collars which provide a base floor price of US$50/bbl through 2007 on 15,000 bbl/d of the Company's heavy oil production.

- During Q3/06, the Company contributed approximately 127,000 bbl/d of its heavy crude oil streams to the Western Canadian Select ("WCS") blend as market conditions resulted in this strategy offering the optimal pricing for bitumen.

- Under its three phase heavy crude oil marketing plan, Canadian Natural continues to encourage the development of additional heavy crude oil conversion capacity. During Q3/06 Canadian Natural entered into an agreement to sell 25,000 bbl/d of heavy crude oil production to a new merchant upgrader to be constructed in Alberta. The agreement is for a period of 5 years, with first deliveries anticipated to occur in 2010 upon completion of construction of the facilities.

- AECO benchmark pricing for natural gas was 4% lower than in the previous quarter, reflecting the impact of high regional storage levels in North America.

FINANCIAL REVIEW

- Canadian Natural has structured its financial position so as to be able to profitably grow its conventional crude oil and natural gas operations over the next several years and to build the financial capacity to complete the Horizon Project and other major projects. A brief summary of its strengths are:

  – A diverse asset base geographically and by product - produced in excess of 561,000 boe/d in Q3/06, comprised of approximately 43% natural gas and 57% crude oil - with 94% of production located in G7 countries with stable and secure economies.

  – Financial stability and liquidity – approximately $3.5 billion of bank credit facilities, of which Canadian Natural had in aggregate $2.2 billion of unused bank lines available at September 30, 2006.

- Strong balance sheet at September 30, 2006 - with a debt to book capitalization ratio of 35%, debt to cash flow of 1.1x, debt to EBITDA of 1.0x and shareholders' equity of $10.4 billion.

- During the third quarter of 2006, in anticipation of the acquisition of ACC, the Board of Directors amended the Company's commodity hedging program. The commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditure program throughout the Horizon Project construction period. This program was temporarily amended to allow for the hedging of up to 75% of the expected production to the end of 2007 and up to 50% of the expected 2008 production through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 60% of expected crude oil volumes and approximately 70% of the expected natural gas volumes have been hedged for the remainder of 2006 and 2007. In 2007 the Company will revert to the original hedging program which allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48.

- As effective as commodity hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management liability reflects, at September 30, 2006, the implied price differentials for the non-designated hedges for future years. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at September 30, 2006. Due to changes in the crude oil and natural gas forward pricing and the settlement of a portion of 2006 contracts as at September 30, 2006, the Company recorded a net pre-tax $772 million ($508 million after-tax) unrealized gain on its risk management activities for the nine months ended September 30, 2006 (September 30, 2005 - unrealized pre-tax loss of $1,750 million), including a pre-tax $754 million ($496 million after-tax) unrealized gain for the three months ended September 30, 2006 (September 30, 2005 - unrealized pre-tax loss of $633 million; June 30, 2006 - unrealized pre-tax gain of $26 million).

- In addition to the risk management liability recognized on the balance sheet at September 30, 2006, the net unrecognized asset related to the fair value of derivative financial instruments designated as hedges was $195 million at September 30, 2006 (December 31, 2005 – net unrecognized liability of $990 million).

- During Q3/06 under the terms of the Normal Course Issuer Bid, which allows for the repurchase by the Company of up to 26.9 million shares through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, 95,000 common shares were repurchased at an average price of $58.97/share.

OUTLOOK

The Company has revised its annual production guidance to include the effect of ACC from November 2006 and currently expects 2006 production levels before royalties to average 1,492 to 1,501 mmcf/d of natural gas and 325 to 336 mbbl/d of crude oil and NGLs. Q4/06 production guidance before royalties is 1,620 to 1,658 mmcf/d of natural gas and 324 to 344 mbbl/d of crude oil and NGLs.

Detailed guidance on revised production levels, capital allocation and operating costs can be found on the Company's website at http://www.cnrl.com/investor_info/corporate_guidance/.

2007 BUDGET

- Crude oil and NGLs production target of 315,000 – 360,000 bbl/d before royalties representing a midpoint increase of 2% from the midpoint of 2006 annual guidance. Crude oil capital has been maintained with 2006 levels as we continue to develop long term production growth projects at Pelican Lake and in-situ oilsands at Primrose.
- For 2007, excluding stratigraphic and service wells, Canadian Natural expects to drill 666 North American crude oil wells, an increase of 2% compared to 2006 drilling levels with the majority of additional drilling targeting conventional heavy oil.
- Natural gas production target of 1,594 – 1,664 mmcf/d before royalties representing a midpoint increase of 9% from the midpoint of 2006 annual guidance. Natural gas capital has been reduced by approximately 40% from 2006 levels as a result of the shift in capital allocation to higher return crude oil projects in the near term.
- Allocation of capital between Canadian Natural and newly acquired ACC lands will be the result of a high-grading process focusing on highest return projects. No changes to the long-term natural gas plans of the Company are contemplated. As a result, 2007 natural gas drilling has been reduced significantly.
- For 2007, Canadian Natural plans on drilling 423 natural gas wells in North America, which represents a decrease of 43% compared to 2006 drilling levels. This planned reduction reflects the continuation of the shift made earlier in 2006 to higher return crude oil projects as a result of lower manpower intensity for crude oil drilling and completions and higher crude oil pricing. No changes were made to the long-term natural gas program where competitive drainage or lease expiries could impact development.
- Equivalent production target of 581,000 – 637,000 boe/d before royalties representing a midpoint increase of 5% from the midpoint of 2006 annual guidance.
- Cash flow estimate of $5.6 billion - $6.0 billion ($10.40 – $11.20 per common share) based upon a forecast average West Texas Intermediate oil price of US$65/bbl, an AECO natural gas price of C$7.35/GJ and an exchange rate of C$1.00 = US$0.8929.
- Strong 2007 commodity hedging program with a combination of costless collars, put contracts and physical sales contracts on majority of total natural gas production. Details of the hedge position are shown in note 7 of the consolidated financial statements.
- Continued strong balance sheet management with targeted debt to book capitalization at the end of 2007 of approximately 45% and debt to EBITDA of 1.6 times.
- The budgeted capital expenditures in 2007 are currently expected to be as follows:

($ millions)	**2007 Budget**	2006 Forecast
Conventional oil and gas		
North America natural gas	**$ 1,111**	$ 1,914
North America crude oil and NGLs	**1,350**	1,296
North Sea	**521**	651
Offshore West Africa	**114**	146
Acquisition of Anadarko Canada Corporation	**-**	4,528
Property acquisitions, dispositions and midstream	**16**	(28)
	3,112	8,507
Horizon Oil Sands Project Phase 1 construction	**2,610** (1)	2,561
Capitalized interest and other items	**397**	222
Horizon Oil Sands Project Phase 2/3 engineering	**109**	128
Canadian Natural Upgrader engineering	**25**	3
	$ 6,253	$ 11,421

(1) Forecast to be in the range of $2,410 million to $2,810 million, the final level of expenditure will be dependent upon the ability of certain contractors to advance portions of their efforts from 2008 into 2007 as well as the extent of any realized cost pressures on certain isolated portions of the project.

The above capital expenditure budget incorporates the following levels of drilling activity:

Drilling activity (number of net wells)	**2007 Budget**	2006 Forecast
Targeting natural gas	**423**	740
Targeting crude oil	**676**	668
Stratigraphic test / service wells, including Horizon Project	**311**	365
Total	**1,410**	1,773

Drilling Program

The 2007 North America drilling program is highlighted by the high-grading of our natural gas asset base, continued development of Pelican Lake and another strong conventional heavy program and consists of:

(number of net wells)	**2007 Budget**	2006 Forecast
Natural gas	**423**	740
Crude oil		
Conventional heavy crude oil	**369**	318
Thermal oil sands	**58**	67
Light crude oil	**107**	121
Pelican Lake crude oil	**132**	149
Stratigraphic test / service wells, excluding Horizon Project	**147**	209
Total	**1,236**	1,604

Horizon Oil Sands Project

- The 2007 capital for Phase 1 construction of the Horizon Project is forecast to be in the range of $2,410 million to $2,810 million. The final level of expenditure will be dependent upon the ability of certain of the contractors to advance portions of their efforts from 2008 into 2007 as well as the extent of any realized cost pressures on certain isolated portions of the project.

- The 2007 capital budget for the Horizon Project targets the completion of most major plants with the commissioning process to be substantially underway. The Ore Preparation Plant and Tailings Systems are targeted to be mechanically complete and ready to commission with the majority of utilities and offsites systems operational. The Upgrader is targeted to be nearing completion, with half of the related plants completed. A total of 156 stratigraphic test wells will be drilled on the Horizon Project leases during 2007.

International

- A total of 7.4 producer wells and 7.2 service wells will be drilled in the North Sea. Additionally, the development of the Lyell Field is targeted for completion in late 2007.

- At West Espoir an additional 3.0 producer wells will be drilled and 1.2 service wells.

MANAGEMENT’S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the “Company”) may constitute “forward-looking statements” within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company “believes”, “anticipates”, “expects”, “plans”, “estimates”, ”targets”, or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; foreign currency exchange rates; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition, availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); asset retirement obligations; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available. Statements relating to “reserves” are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management’s estimates or opinions change.

Management's Discussion and Analysis

Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Canadian Natural Resources Limited (the "Company"), should be read in conjunction with the unaudited interim consolidated financial statements for the nine months ended September 30, 2006 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2005.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and EBITDA (net earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities). These financial measures are not defined by GAAP and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with GAAP, as an indication of the Company's performance. The measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings in the "Financial Highlights" section.

Certain prior period amounts have been reclassified to enable comparison with the current period's presentation.

The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

Production volumes are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices exclude the effect of risk management activities, except where noted otherwise. Production on an "after royalty" or "net" basis is presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the nine and three months ended September 30, 2006 in relation to the comparable periods in 2005 and the second quarter of 2006. The accompanying tables form an integral part of this MD&A. This MD&A is dated October 27, 2006.

FINANCIAL HIGHLIGHTS
(millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Revenue, before royalties	**$ 2,859**	$ 2,717	$ 2,918	**$ 7,948**	$ 7,075
Net earnings (loss)	**$ 1,116**	$ 1,038	$ 151	**$ 2,211**	$ (54)
Per common share – basic	**$ 2.08**	$ 1.93	$ 0.28	**$ 4.12**	$ (0.10)
– diluted	**$ 2.08**	$ 1.93	$ 0.28	**$ 4.12**	$ (0.10)
Adjusted net earnings from operations[1]	**$ 470**	$ 514	$ 593	**$ 1,252**	$ 1,433
Per common share – basic	**$ 0.87**	$ 0.96	$ 1.10	**$ 2.33**	$ 2.67
– diluted	**$ 0.87**	$ 0.96	$ 1.10	**$ 2.33**	$ 2.67
Cash flow from operations[2]	**$ 1,313**	$ 1,287	$ 1,386	**$ 3,639**	$ 3,531
Per common share – basic	**$ 2.44**	$ 2.40	$ 2.58	**$ 6.77**	$ 6.58
– diluted	**$ 2.44**	$ 2.40	$ 2.57	**$ 6.77**	$ 6.58
Capital expenditures, net of dispositions	**$ 1,661**	$ 1,558	$ 1,272	**$ 5,528**	$ 3,253

(1) Adjusted net earnings from operations is a non-GAAP term that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The following reconciliation lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

	Three Months Ended			*Nine Months Ended*	
($ millions)	***Sep 30 2006***	*Jun 30 2006*	*Sep 30 2005*	***Sep 30 2006***	*Sep 30 2005*
Net earnings (loss) as reported	***$ 1,116***	*$ 1,038*	*$ 151*	***$ 2,211***	*$ (54)*
Stock-based compensation (recovery) expense, net of tax[a]	***(92)***	*(21)*	*135*	***(25)***	*406*
Unrealized risk management (gain) loss, net of tax[b]	***(496)***	*(17)*	*430*	***(508)***	*1,190*
Unrealized foreign exchange loss (gain), net of tax[c]	***9***	*(48)*	*(104)*	***(31)***	*(90)*
Effect of statutory tax rate changes on future income tax liabilities[d]	***(67)***	*(438)*	*(19)*	***(395)***	*(19)*
Adjusted net earnings from operations	***$ 470***	*$ 514*	*$ 593*	***$ 1,252***	*$ 1,433*

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of the outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value, net of taxes, flow through net earnings, or are capitalized to the Horizon Oil Sands Project.

(b) Financial instruments not designated as hedges are recorded at fair value on the balance sheet, with changes in fair value, net of taxes, flowing through net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates and are immediately recognized in net earnings.

(d) All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's balance sheet in determining its future income tax assets and liabilities. The impact of the tax rate changes is recorded in net earnings in the period the legislation is substantively enacted. During the first quarter of 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production, resulting in an increase of future tax liabilities of $110 million. During the second quarter of 2006, the Canadian Federal Government enacted reductions to its corporate income tax rates, resulting in a reduction of future income tax liabilities of approximately $277 million. Also during the second quarter of 2006, the provinces of Alberta and Saskatchewan enacted reductions to their corporate income tax rates, resulting in a reduction of future tax liabilities of approximately $161 million. During the third quarter of 2006, the Government of Côte d'Ivoire enacted reductions to its corporate income tax rate, resulting in a reduction of future income tax liabilities of approximately $67 million.

(2) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Cash flow from operations may not be comparable to similar measures presented by other companies.

	Three Months Ended			Nine Months Ended	
($ millions)	***Sep 30 2006***	*Jun 30 2006*	*Sep 30 2005*	***Sep 30 2006***	*Sep 30 2005*
Net earnings (loss)	***$ 1,116***	*$ 1,038*	*$ 151*	***$ 2,211***	*$ (54)*
Non-cash items:					
Depletion, depreciation and amortization	***589***	*557*	*505*	***1,667***	*1,463*
Asset retirement obligation accretion	***17***	*16*	*18*	***50***	*53*
Stock-based compensation (recovery) expense	***(135)***	*(34)*	*199*	***(37)***	*598*
Unrealized risk management (gain) loss	***(754)***	*(26)*	*633*	***(772)***	*1,750*
Unrealized foreign exchange loss (gain)	***11***	*(58)*	*(124)*	***(37)***	*(108)*
Deferred petroleum revenue tax (recovery) expense	***(4)***	*18*	*(14)*	***40***	*(10)*
Future income tax expense (recovery)	***473***	*(224)*	*18*	***517***	*(161)*
Cash flow from operations	***$ 1,313***	*$ 1,287*	*$ 1,386*	***$ 3,639***	*$ 3,531*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the nine months ended September 30, 2006, the Company reported record net earnings of $2,211 million compared to a net loss of $54 million for the nine months ended September 30, 2005. Net earnings for the nine months ended September 30, 2006 included unrealized after-tax income of $959 million related to the effects of risk management activities, statutory tax rate changes on future income tax liabilities, foreign exchange gains and stock-based compensation recovery, compared to $1,487 million of net after-tax expenses for the nine months ended September 30, 2005. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2006 decreased to $1,252 million from $1,433 million for the nine months ended September 30, 2005, primarily due to lower natural gas pricing, higher realized risk management losses, higher production costs and depletion, depreciation and amortization expense, and the impact of a stronger Canadian dollar relative to the US dollar. These factors were partially offset by stronger crude oil pricing and higher crude oil sales volumes.

For the third quarter of 2006, the Company reported record quarterly net earnings of $1,116 million compared to net earnings of $151 million in the third quarter of 2005 and net earnings of $1,038 million for the prior quarter. Net earnings in the third quarter of 2006 included unrealized after-tax income of $646 million related to the effects of risk management activities, stock-based compensation recovery, statutory tax rate changes on future income tax liabilities and foreign exchange losses, compared to net after-tax expenses of $442 million in the third quarter of 2005 and $524 million of after-tax income in the prior quarter. Excluding these items, adjusted net earnings from operations in the third quarter of 2006 decreased to $470 million from $593 million in the comparable period in 2005, and decreased from $514 million in the prior quarter. The decrease from the comparable period in 2005 was primarily due to lower natural gas pricing, higher realized losses from risk management activities and the impact of a stronger Canadian dollar relative to the US dollar. These factors were offset by the impact of higher crude oil pricing and higher crude oil sales volumes. The decrease from the prior quarter was primarily due to lower natural gas pricing and lower natural gas production, offset by higher crude oil sales in the North Sea due to the timing of liftings.

The Company expects that consolidated net earnings will continue to reflect significant quarterly volatility due to the impact of risk management activities, stock-based compensation expense and fluctuations in foreign exchange rates.

During the third quarter of 2006, in anticipation of the acquisition of Anadarko Canada Corporation ("ACC"), the Board of Directors amended the Company's commodity hedging program. The commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditure program throughout the Horizon Oil Sands Project ("Horizon Project") construction period. This program was temporarily amended to allow for the hedging of up to 75% of the expected production to the end of 2007 and up to 50% of the expected 2008 production through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 60% of expected crude oil volumes and approximately 70% of expected natural gas volumes have been hedged for the remainder of 2006 and 2007. In 2007, the Company will revert to the original hedging program that allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48.

As effective as the Company's hedges are against reference commodity prices, a portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management liability reflects, at September 30, 2006, the implied price differentials for the non-designated hedges for future periods. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at September 30, 2006.

Due to the changes in crude oil and natural gas forward pricing, and the settlement of a portion of 2006 contracts, the Company recorded a net $772 million ($508 million after-tax) unrealized gain on its risk management activities for the nine months ended September 30, 2006, including a $754 million ($496 million after-tax) unrealized gain for the three months ended September 30, 2006. Mark-to-market unrealized gains and losses do not impact the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas sales.

The Company also recorded a $37 million ($25 million after-tax) stock-based compensation recovery for the nine months ended September 30, 2006 in connection with the 12% decrease in the Company's share price, and a $135 million ($92 million after-tax) stock-based compensation recovery as a result of the 17% decrease in the Company's share price for the three months ended September 30, 2006 (Company's share price as at: September 30, 2006 - C$50.94; June 30, 2006 - C$61.72; December 31, 2005 - C$57.63; September 30, 2005 - C$52.50). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options, based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued each quarter to reflect the changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in earnings, or capitalized as part of the Horizon Project during the construction period. The stock-based compensation liability reflects the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on September 30, 2006. In periods when substantial stock price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

Cash flow from operations for the nine months ended September 30, 2006 increased to $3,639 million from $3,531 million for the nine months ended September 30, 2005. Cash flow from operations in the third quarter of 2006 decreased to $1,313 million from $1,386 million for the third quarter of 2005 and increased 2% from $1,287 million in the prior quarter. Cash flow from operations for the nine months ended September 30, 2006 increased from the comparable period in 2005 primarily due to higher crude oil pricing and higher crude oil sales volumes. These factors were partially offset by lower natural gas pricing, higher realized losses from risk management activities, higher production costs and the impact of a stronger Canadian dollar relative to the US dollar. The decrease from the third quarter in 2005 was primarily due to lower natural gas pricing, higher realized losses from risk management activities and the impact of a stronger Canadian dollar relative to the US dollar. These factors were offset by the impact of increased crude oil pricing. The increase from the prior quarter was primarily related to the timing of liftings in the North Sea, partially offset by lower natural gas pricing and production.

Total production before royalties averaged a record 569,590 boe/d for the nine months ended September 30, 2006, up 5% from 544,688 boe/d for the nine months ended September 30, 2005. Production for the third quarter of 2006 decreased 2% to 561,152 boe/d from 571,911 boe/d in the third quarter of 2005 and decreased 4% from 584,611 boe/d in the prior quarter.

In the fourth quarter of 2006, the Company expects to complete the acquisition of ACC, a subsidiary of Anadarko Petroleum Corporation, for aggregate consideration of US$4.075 billion, before working capital and other adjustments. ACC's land and production base is located in Western Canada and consists of natural gas weighted assets. The current production, before royalties, that the Company expects to acquire is approximately 358 mmcf/d of natural gas and 9,300 bbl/d of crude oil and NGLs.

OPERATING HIGHLIGHTS

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Crude oil and NGLs ($/bbl)[1]					
Sales price[2]	**$ 62.55**	$ 60.05	$ 57.35	**$ 55.91**	$ 47.04
Royalties	**5.11**	5.14	5.11	**4.61**	4.00
Production expense	**13.47**	11.92	11.48	**12.29**	11.48
Netback	**$ 43.97**	$ 42.99	$ 40.76	**$ 39.01**	$ 31.56
Natural gas ($/mcf)[1]					
Sales price[2]	**$ 5.83**	$ 6.16	$ 8.61	**$ 6.75**	$ 7.53
Royalties	**1.11**	1.11	1.93	**1.31**	1.57
Production expense	**0.84**	0.80	0.76	**0.81**	0.72
Netback	**$ 3.88**	$ 4.25	$ 5.92	**$ 4.63**	$ 5.24
Barrels of oil equivalent ($/boe)[1]					
Sales price[2]	**$ 51.21**	$ 50.36	$ 54.87	**$ 49.38**	$ 46.17
Royalties	**5.75**	5.80	7.84	**5.99**	6.40
Production expense	**10.01**	8.85	8.56	**9.13**	8.31
Netback	**$ 35.45**	$ 35.71	$ 38.47	**$ 34.26**	$ 31.46

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Including transportation costs and excluding risk management activities.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
WTI benchmark price (US$/bbl)	**$ 70.55**	$ 70.70	$ 63.17	**$ 68.29**	$ 55.45
Dated Brent benchmark price (US$/bbl)	**$ 69.58**	$ 69.63	$ 61.47	**$ 67.03**	$ 53.63
Differential to LLB blend (US$/bbl)	**$ 19.08**	$ 17.79	$ 18.73	**$ 21.82**	$ 19.74
LLB blend differential from WTI (%)	**27%**	25%	30%	**32%**	36%
Condensate benchmark price (US$/bbl)	**$ 70.26**	$ 71.51	$ 63.40	**$ 68.49**	$ 56.18
NYMEX benchmark price (US$/mmbtu)	**$ 6.52**	$ 6.83	$ 8.23	**$ 7.47**	$ 7.12
AECO benchmark price (C$/GJ)	**$ 5.72**	$ 5.95	$ 7.73	**$ 6.82**	$ 7.03
US / Canadian dollar average exchange rate (US$)	**0.8919**	0.8918	0.8325	**0.8830**	0.8170

Average world crude oil prices continued to remain strong in the third quarter of 2006 due to continued demand growth and ongoing geopolitical uncertainties, despite high crude oil inventories. However, pricing significantly declined as the quarter progressed. In September 2006, crude oil prices averaged US$63.90 per bbl, a decline of 18% from the record high of US$78.40 per bbl reached in July 2006.

West Texas Intermediate ("WTI") averaged US$68.29 per bbl for the nine months ended September 30, 2006, an increase of 23% compared to US$55.45 per bbl for the nine months ended September 30, 2005. In the third quarter of 2006, WTI averaged US$70.55 per bbl, an increase of 12% from US$63.17 per bbl in the comparable period in 2005 and down slightly from US$70.70 per bbl in the prior quarter. The Company's realized crude oil price increased from the comparable periods in 2005 as a result of the increased WTI price and the narrower Heavy Crude Oil Differential from WTI ("Heavy Differential"). Heavy Differentials averaged 32% for the nine months ended September 30, 2006 compared to 36% for the nine months ended September 30, 2005. For the three months ended September 30, 2006, Heavy Differentials averaged 27% compared to 30% for the third quarter of 2005, but increased slightly from the prior quarter. The narrowing of the Heavy Differentials in 2006 from the comparable periods in 2005 was primarily due to strong seasonal demand for asphalt products, reduced availability of imported grades from Venezuela and Mexico and the removal of logistical constraints in accessing new markets in the US Gulf Coast due to the Pegasus and Spearhead pipelines. The increase in North America realized crude oil prices from the comparable periods in 2005 was partially offset by the impact of a strengthening Canadian dollar relative to the US dollar. A strengthening Canadian dollar reduces the Canadian dollar sales price the Company receives for its crude oil sales, as crude oil prices are based on US dollar denominated benchmarks.

The Company anticipates continued volatility in the crude oil markets as current inventory levels remain high and geopolitical events are unpredictable.

Dated Brent ("Brent") averaged US$67.03 per bbl for the nine months ended September 30, 2006, an increase of 25% compared to US$53.63 per bbl for the nine months ended September 30, 2005. In the third quarter of 2006, Brent averaged US$69.58 per bbl, an increase of 13% from US$61.47 per bbl in the comparable period in 2005 due to increased demand. Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Brent pricing, which have benefited from strong European and Asian demand.

NYMEX natural gas prices averaged US$7.47 per mmbtu for the nine months ended September 30, 2006, an increase of 5% from US$7.12 per mmbtu for the nine months ended September 30, 2005. In the third quarter of 2006, the NYMEX natural gas price decreased 21% to average US$6.52 per mmbtu from US$8.23 per mmbtu in the comparable period in 2005, and decreased 5% from US$6.83 per mmbtu in the prior quarter. AECO natural gas pricing for the nine months ended September 30, 2006 decreased 3% from the nine months ended September 30, 2005 to average C$6.82 per GJ. AECO natural gas pricing for the three months ended September 30, 2006 decreased 26% from the comparable period in 2005 and 4% from the prior quarter to average C$5.72 per GJ. The decrease in natural gas pricing from the comparable periods reflected the impact of exceptionally mild weather to date in 2006, relatively low demand for electricity during the summer cooling months and the continuing impact of high natural gas inventory levels.

The Company anticipates a challenging pricing environment in the near term given the very strong storage levels. Longer term natural gas pricing will continue to be weather dependent.

PRODUCT PRICES[1]

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Crude oil and NGLs ($/bbl)[2]					
North America	**$ 55.97**	$ 54.94	$ 51.77	**$ 48.82**	$ 40.20
North Sea	**$ 78.68**	$ 73.19	$ 74.46	**$ 74.09**	$ 66.49
Offshore West Africa	**$ 70.59**	$ 72.97	$ 59.09	**$ 69.58**	$ 59.51
Company average	**$ 62.55**	$ 60.05	$ 57.35	**$ 55.91**	$ 47.04
Natural gas ($/mcf)[2]					
North America	**$ 5.86**	$ 6.21	$ 8.69	**$ 6.81**	$ 7.60
North Sea	**$ 2.38**	$ 2.33	$ 2.64	**$ 2.36**	$ 3.11
Offshore West Africa	**$ 4.97**	$ 5.30	$ 5.52	**$ 5.27**	$ 6.39
Company average	**$ 5.83**	$ 6.16	$ 8.61	**$ 6.75**	$ 7.53
Company average ($/boe)[2]	**$ 51.21**	$ 50.36	$ 54.87	**$ 49.38**	$ 46.17
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**72%**	68%	60%	**65%**	57%
Natural gas	**28%**	32%	40%	**35%**	43%

(1) Including transportation costs and excluding risk management activities.

(2) Amounts expressed on a per unit basis are based on sales volumes.

The Company's realized crude oil prices increased 19% to average a record $55.91 per bbl for the nine months ended September 30, 2006 from $47.04 per bbl for the nine months ended September 30, 2005. Realized crude oil prices for the third quarter of 2006 increased 9% to average a record $62.55 per bbl from $57.35 per bbl in the third quarter of 2005, and increased 4% from $60.05 per bbl in the prior quarter. The increase from the comparable periods in 2005 was due to higher benchmark crude oil prices and a narrower Heavy Differential, partially offset by the impact of a stronger Canadian dollar. The increase from the prior quarter was primarily due to higher benchmark crude oil prices.

The Company's realized natural gas price decreased 10% to average $6.75 per mcf for the nine months ended September 30, 2006 from $7.53 per mcf for the nine months ended September 30, 2005. This decrease reflected record levels of natural gas inventory in North America, which were primarily due to the impact of exceptionally mild weather early in 2006 that reduced seasonal heating demand and stable summer weather that reduced cooling demand. In the third quarter of 2006, the Company's realized natural gas price decreased 32% from $8.61 per mcf in the third quarter of 2005 and decreased 5% from $6.16 per mcf for the prior quarter primarily due to the above factors.

North America

North America realized crude oil prices increased 21% to average $48.82 per bbl for the nine months ended September 30, 2006 from $40.20 per bbl for the nine months ended September 30, 2005. Realized crude oil prices in the third quarter of 2006 averaged $55.97 per bbl, an 8% increase from $51.77 per bbl in the comparable period in 2005, and increased slightly from $54.94 per bbl in the prior quarter. The increase from the comparable periods in 2005 was due to higher benchmark crude oil prices and a narrower Heavy Differential, partially offset by the impact of a stronger Canadian dollar.

In North America, the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During the third quarter, the Company contributed approximately 127,000 bbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream. The Company also continues to work with refiners to advance expansion of heavy crude oil conversion capacity, and is working with pipeline companies to develop new capacity to the Canadian West Coast and the US Gulf Coast where crude oil cargos can be sold on a world-wide basis. With a view to expanding markets for its heavy crude oil, the Company has committed to 25,000 bbl/d of capacity on the Pegasus Pipeline, which carries crude oil to the Gulf of Mexico. The Pegasus Pipeline is made up of a series of segments extending from Patoka, Illinois to Nederland, Texas, near the Gulf Coast. The Company's first sales from the Pegasus Pipeline occurred in April 2006. In the third quarter of 2006, the Company entered into an agreement to supply 25,000 bbl/d of heavy crude oil production to a new merchant upgrader to be constructed in Alberta. The agreement is for a period of five years with first deliveries anticipated to occur in 2010 upon completion of construction of the facilities.

North America realized natural gas prices decreased 10% to average $6.81 per mcf for the nine months ended September 30, 2006 from $7.60 per mcf for the nine months ended September 30, 2005. The realized natural gas price in the third quarter of 2006 averaged $5.86 per mcf, a decrease of 33% from $8.69 per mcf in the comparable period in 2005 and a decrease of 6% from $6.21 per mcf for the prior quarter.

A comparison of the price received for the Company's North America production by product type is as follows:

	Sep 30 2006	Jun 30 2006	Sep 30 2005
Wellhead Price[(1)(2)]			
Light / medium crude oil and NGLs (C$/bbl)	**$ 72.25**	$ 69.25	$ 66.62
Pelican Lake crude oil (C$/bbl)	**$ 53.84**	$ 56.01	$ 50.30
Primary heavy crude oil (C$/bbl)	**$ 52.15**	$ 51.78	$ 48.86
Thermal heavy crude oil (C$/bbl)	**$ 50.36**	$ 47.64	$ 44.84
Natural gas (C$/mcf)	**$ 5.86**	$ 6.21	$ 8.69

(1) Including transportation costs and excluding risk management activities.

(2) Amounts expressed on a per unit basis are based on sales volumes.

North Sea

North Sea realized crude oil prices increased 11% to average $74.09 per bbl for the nine months ended September 30, 2006 from $66.49 per bbl for the nine months ended September 30, 2005. Realized crude oil prices in the third quarter of 2006 increased 6% to average $78.68 per bbl from $74.46 per bbl in the third quarter of 2005 and increased 8% from $73.19 per bbl in the prior quarter. The increase in the realized crude oil price from the comparable periods in 2005 and the prior quarter was due mainly to the impact of strong European and Asian demand on Brent pricing, partially offset by the strengthening Canadian dollar in 2006 compared to 2005.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 17% to average $69.58 per bbl for the nine months ended September 30, 2006 from $59.51 per bbl for the nine months ended September 30, 2005. Realized crude oil prices for the third quarter of 2006 increased 19% to average $70.59 per bbl from $59.09 per bbl in the third quarter of 2005 and decreased 3% from $72.97 per bbl in the prior quarter. The increase in the realized crude oil price from the comparable periods in 2005 was due mainly to the impact of strong European and Asian demand on Brent pricing, partially offset by the strengthening Canadian dollar. The decrease from the prior quarter was primarily due to the timing of liftings.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place, referred to as "liftings" in this MD&A. The related cumulative crude oil inventory volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**Sep 30 2006**	Jun 30 2006	Dec 31 2005
North America, related to pipeline fill	**1,097,526**	1,097,526	484,157
North Sea, related to timing of liftings	**243,635**	2,397,640	747,141
Offshore West Africa, related to timing of liftings	**711,096**	832,317	412,841
	2,052,257	4,327,483	1,644,139

In the third quarter of 2006, approximately 2.3 million barrels of crude oil previously produced in the Company's international operations were sold and included in the third quarter results of operations. This reduction in inventory increased cash flow from operations by approximately $55 million in the third quarter of 2006.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Crude oil and NGLs (bbl/d)					
North America	**233,440**	234,780	231,260	**230,430**	218,774
North Sea	**53,988**	63,703	73,543	**59,473**	69,198
Offshore West Africa	**34,237**	40,369	29,921	**38,150**	16,064
	321,665	338,852	334,724	**328,053**	304,036
Natural gas (mmcf/d)					
North America	**1,416**	1,448	1,400	**1,425**	1,421
North Sea	**11**	17	18	**15**	19
Offshore West Africa	**10**	10	5	**9**	4
	1,437	1,475	1,423	**1,449**	1,444
Total barrel of oil equivalent (boe/d)	**561,152**	584,611	571,911	**569,590**	544,688
Product mix					
Light/medium crude oil and NGLs	**24%**	26%	27%	**26%**	25%
Pelican Lake crude oil	**5%**	5%	4%	**5%**	4%
Primary heavy crude oil	**16%**	16%	16%	**16%**	17%
Thermal heavy crude oil	**12%**	11%	11%	**11%**	10%
Natural gas	**43%**	42%	42%	**42%**	44%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Crude oil and NGLs (bbl/d)					
North America	**205,087**	205,674	200,055	**201,214**	189,630
North Sea	**53,911**	63,552	73,424	**59,361**	69,101
Offshore West Africa	**31,864**	39,335	29,162	**36,693**	15,624
	290,862	308,561	302,641	**297,268**	274,355
Natural gas (mmcf/d)					
North America	**1,144**	1,183	1,085	**1,149**	1,125
North Sea	**11**	17	18	**15**	19
Offshore West Africa	**9**	10	5	**9**	4
	1,164	1,210	1,108	**1,173**	1,148
Total barrel of oil equivalent (boe/d)	**484,872**	510,243	487,292	**492,759**	465,675

Daily production and per barrel statistics are presented throughout the MD&A on a “before royalty” or “gross” basis. Production on an “after royalty” or “net” basis is presented for information purposes only.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Total crude oil and natural gas production averaged a record 569,590 boe/d for the nine months ended September 30, 2006, a 5% increase from the nine months ended September 30, 2005. Third quarter total production in 2006 averaged 561,152 boe/d, a decrease of 2% from the third quarter of 2005 and a decrease of 4% from the prior quarter. The increase in production from the nine months ended September 30, 2005 reflects increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, continued organic growth from the Company's North America capital expenditure program and the full nine month impact of production from the Baobab Field located offshore Côte d'Ivoire. Production from this Field began in August 2005. The decrease from the third quarter of 2005 and the prior quarter was primarily due to the impact of reduced natural gas drilling activity in North America in 2006, planned maintenance shutdowns in the North Sea and production curtailments at Baobab.

Total crude oil and NGLs production for the nine months ended September 30, 2006 increased 8% to 328,053 bbl/d from 304,036 bbl/d for the nine months ended September 30, 2005. In the third quarter of 2006, production decreased 4% to 321,665 bbl/d from 334,724 bbl/d in the third quarter of 2005 and decreased 5% from 338,852 bbl/d in the prior quarter. Crude oil and NGLs production in the third quarter of 2006 was within the Company's previously issued guidance of 318,000 to 340,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering, accounting for over 40% of the Company's total production. Natural gas production for the nine months ended September 30, 2006 averaged 1,449 mmcf/d compared to 1,444 mmcf/d for the nine months ended September 30, 2005. In the third quarter of 2006, natural gas production averaged 1,437 mmcf/d compared to 1,423 mmcf/d in the third quarter of 2005 and decreased 3% from 1,475 mmcf/d in the prior quarter. The Company's third quarter natural gas production was also within the Company's previously issued guidance of 1,416 to 1,445 mmcf/d.

As a result of the planned acquisition of ACC, the Company has revised its annual production guidance. In 2006, production is expected to average 325,000 to 336,000 bbl/d of crude oil and NGLs and 1,492 to 1,501 mmcf/d of natural gas. Fourth quarter 2006 production guidance is 324,000 to 344,000 bbl/d of crude oil and NGLs and 1,620 to 1,658 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the nine months ended September 30, 2006 increased 5% to average 230,430 bbl/d from 218,774 bbl/d for the nine months ended September 30, 2005. Production in the third quarter of 2006 was relatively unchanged at 233,440 bbl/d compared to 231,260 bbl/d in the third quarter of 2005 and 234,780 bbl/d in the prior quarter. The increase in crude oil and NGLs production for the nine months ended September 30, 2006 was mainly due to increased Primrose production and the positive results from the Pelican Lake waterflood project.

North America natural gas production of 1,425 mmcf/d for the nine months ended September 30, 2006 remained relatively unchanged from production of 1,421 mmcf/d for the nine months ended September 30, 2005. Third quarter 2006 production of 1,416 mmcf/d increased slightly from production of 1,400 mmcf/d in the third quarter of 2005 and decreased 2% from 1,448 mmcf/d in the prior quarter. The Company's natural gas production was impacted by its decision to reduce its planned drilling activity for the balance of 2006 in response to continuing low prices for natural gas and the anticipated acquisition of ACC.

North Sea

North Sea crude oil production for the nine months ended September 30, 2006 averaged 59,473 bbl/d, 14% lower than the 69,198 bbl/d in the nine months ended September 30, 2005. Crude oil production in the third quarter of 2006 decreased to 53,988 bbl/d, 27% lower than production of 73,543 bbl/d in the comparable period in 2005, and 15% lower than prior quarter production of 63,703 bbl/d. Production levels for the third quarter were in line with expectations, reflecting planned maintenance shutdowns.

Offshore West Africa

Offshore West Africa crude oil production for the nine months ended September 30, 2006 increased 137% to 38,150 bbl/d from 16,064 bbl/d for the nine months ended September 30, 2005, primarily due to the commencement of production from the 57.61% owned and operated Baobab Field in August 2005. Production during the third quarter of 2006 increased 14% from 29,921 bbl/d in the third quarter of 2005 due to a full quarter of Baobab production, the delivery of first oil from West Espoir in July and a successful infill drilling campaign at East Espoir earlier in 2006. Production from the Baobab Field continues to be impacted by increased sand and solids production resulting in the shut in of four production wells for the entire third quarter that contributed to the 15% decrease in production from the prior quarter.

ROYALTIES

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Crude oil and NGLs ($/bbl)[1]					
North America	**$ 6.79**	$ 6.81	$ 6.99	**$ 6.13**	$ 5.36
North Sea	**$ 0.11**	$ 0.17	$ 0.12	**$ 0.13**	$ 0.10
Offshore West Africa	**$ 4.89**	$ 1.87	$ 1.54	**$ 2.74**	$ 1.69
Company average	**$ 5.11**	$ 5.14	$ 5.11	**$ 4.61**	$ 4.00
Natural gas ($/mcf)[1]					
North America	**$ 1.12**	$ 1.13	$ 1.96	**$ 1.34**	$ 1.59
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.34**	$ 0.14	$ 0.13	**$ 0.21**	$ 0.18
Company average	**$ 1.11**	$ 1.11	$ 1.93	**$ 1.31**	$ 1.57
Company average ($/boe)[1]	**$ 5.75**	$ 5.80	$ 7.84	**$ 5.99**	$ 6.40
Percentage of revenue[2]					
Crude oil and NGLs	**8%**	9%	9%	**8%**	9%
Natural gas	**19%**	18%	22%	**19%**	21%
Company average boe	**11%**	12%	14%	**12%**	14%

(1) *Amounts expressed on a per unit basis are based on sales volumes.*

(2) *Including transportation costs and excluding risk management activities.*

North America

North America crude oil and NGLs royalties per bbl for the nine months ended September 30, 2006 primarily reflect the Company's realized crude oil prices received. A significant portion of North America crude oil royalties are calculated as a percentage of forecasted annual net profit after capital costs. Crude oil and NGLs royalties decreased in the third quarter of 2006 from the previous year and the prior quarter, despite strong crude oil benchmark prices, based on current forecasts. Partially offsetting this decrease was the payout of the Company's Primrose oil sands project, which occurred late in the third quarter of 2006. Upon payout, Crown royalty rates on the Primrose Field were increased from 1% of gross revenue to 25% of net profit after capital costs.

Natural gas royalties per mcf fluctuated from the comparable periods in 2005 and the prior quarter in response to benchmark natural gas prices, which were impacted by changes in demand and storage levels for natural gas.

North Sea

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian Field.

Offshore West Africa

Offshore West Africa production is governed by the terms of the various Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery revenue and profit revenue. Cost recovery revenue allows the Company to recover its capital and operating costs and the costs carried by the Company on behalf of the Government State Oil Company. These revenues are reported as sales revenue. Profit revenue is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's share of profit revenue attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the PSCs. Based on current projections, full recovery of the Company's capital investments in the Espoir Field is expected late 2006, which will increase royalty rates and current income taxes in accordance with the PSCs. The Baobab Field payout is now expected to occur around 2012 due to the ongoing production curtailments resulting from limitations to sand screen effectiveness.

In connection with corporate income tax rate reductions enacted by the Government of Côte d'Ivoire during the third quarter, the Company anticipates an increase in future royalty rates in Offshore West Africa in accordance with the terms of the PSC's.

PRODUCTION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Crude oil and NGLs ($/bbl)[1]					
North America	**$ 12.05**	$ 11.71	$ 10.77	**$ 11.58**	$ 10.34
North Sea	**$ 20.28**	$ 17.18	$ 15.15	**$ 18.41**	$ 15.75
Offshore West Africa	**$ 7.97**	$ 5.61	$ 5.81	**$ 6.53**	$ 7.72
Company average	**$ 13.47**	$ 11.92	$ 11.48	**$ 12.29**	$ 11.48
Natural gas ($/mcf)[1]					
North America	**$ 0.83**	$ 0.79	$ 0.74	**$ 0.80**	$ 0.70
North Sea	**$ 1.30**	$ 1.47	$ 2.30	**$ 1.35**	$ 2.57
Offshore West Africa	**$ 1.39**	$ 0.36	$ 1.09	**$ 0.92**	$ 1.21
Company average	**$ 0.84**	$ 0.80	$ 0.76	**$ 0.81**	$ 0.72
Company average ($/boe)[1]	**$ 10.01**	$ 8.85	$ 8.56	**$ 9.13**	$ 8.31

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense per bbl for the nine months ended September 30, 2006 increased to $11.58 from $10.34 for the nine months ended September 30, 2005. Crude oil and NGLs production expense per bbl for the three months ended September 30, 2006 increased to $12.05 from $10.77 for the third quarter in 2005 and from $11.71 for the prior quarter. The increase in production expense from the comparable periods was primarily due to higher industry wide service costs. The increase from the prior quarter also reflects higher cyclic steaming costs, partially offset by reduced fuel costs.

North America natural gas production expense per mcf for the nine and three months ended September 30, 2006 increased over the comparable periods in 2005 and the prior quarter. Natural gas production costs continued to reflect industry wide inflationary pressures.

North Sea

North Sea crude oil production expense varied on a per barrel basis from the comparable periods due to the planned maintenance shutdowns and the lower production volumes on a relatively fixed cost base, as well as the timing of liftings from various fields.

Offshore West Africa

Offshore West Africa crude oil production expenses varied on a per barrel basis from the comparable periods due to the full nine month impact of production from the Baobab Field, which commenced in August 2005, partially offset by continuing operating challenges in the third quarter with sand and solids and the lower production volumes, all on a relatively fixed cost base. During the quarter four wells were shut in, impacting production levels.

MIDSTREAM

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2006**	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Revenue	**$ 19**	$ 17	$ 18	**$ 54**	$ 56
Production expense	**6**	6	5	**17**	16
Midstream cash flow	**13**	11	13	**37**	40
Depreciation	**2**	2	2	**6**	6
Segment earnings before taxes	**$ 11**	$ 9	$ 11	**$ 31**	$ 34

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION [1]

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Expense ($ millions)	**$ 587**	$ 555	$ 503	**$ 1,661**	$ 1,457
$/boe[2]	**$ 10.89**	$ 10.66	$ 9.75	**$ 10.71**	$ 9.87

(1) DD&A excludes depreciation on midstream assets.

(2) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, Depreciation and Amortization ("DD&A") for the nine and three months ended September 30, 2006 increased in total and on a boe basis from the comparable periods in 2005 and the prior quarter. The increase in overall DD&A expense was primarily due to higher sales volumes, higher finding and development costs associated with natural gas exploration in North America and higher estimated future costs to develop the Company's proved undeveloped reserves in the North Sea. DD&A per boe in the third quarter of 2006 reflected a higher proportion of North Sea sales volumes due in part to the timing of liftings in this segment, which has a higher DD&A rate than other segments.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Expense ($ millions)	**$ 17**	$ 16	$ 18	**$ 50**	$ 53
$/boe[1]	**$ 0.31**	$ 0.32	$ 0.34	**$ 0.32**	$ 0.36

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense is the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense on a boe basis in the third quarter of 2006 reflects the impact of higher sales volumes due to timing of liftings in the North Sea.

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2006	Jun 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Net expense ($ millions)	**$ 41**	$ 40	$ 38	**$ 123**	$ 115
$/boe[1]	**$ 0.76**	$ 0.78	$ 0.75	**$ 0.79**	$ 0.78

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for the nine months ended September 30, 2006 increased in total and on a boe basis from the nine months ended September 30, 2005. The increase was primarily due to increased insurance premiums and increased staffing costs. Administration expense on a boe basis in the third quarter of 2006 reflects the impact of higher sales volumes due to timing of liftings in the North Sea.

STOCK-BASED COMPENSATION (RECOVERY) EXPENSE

($ millions)	Three Months Ended Sep 30 2006	Three Months Ended Jun 30 2006	Three Months Ended Sep 30 2005	Nine Months Ended Sep 30 2006	Nine Months Ended Sep 30 2005
Stock option plan (recovery) expense	**$ (135)**	$ (34)	$ 199	**$ (37)**	$ 598

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company recorded a $37 million ($25 million after-tax) stock-based compensation recovery for the nine months ended September 30, 2006 in connection with the 12% decrease in the Company's share price, and a $135 million ($92 million after-tax) stock-based compensation recovery as a result of the decrease in the Company's share price in the third quarter of 2006 (Company's share price as at: September 30, 2006 - C$50.94; June 30, 2006 - C$61.72; December 31, 2005 - C$57.63; September 30, 2005 - C$52.50). As required by GAAP, the Company's outstanding stock options are valued based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. For the nine months ended September 30, 2006 the Company capitalized $38 million in stock-based compensation on the Horizon Project (September 30, 2005 - $64 million). The stock-based compensation liability reflects the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on September 30, 2006. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the nine months ended September 30, 2006, the Company paid $216 million for stock options surrendered for cash settlement (September 30, 2005 - $175 million).

INTEREST EXPENSE

	Three Months Ended Sep 30 2006	Three Months Ended Jun 30 2006	Three Months Ended Sep 30 2005	Nine Months Ended Sep 30 2006	Nine Months Ended Sep 30 2005
Interest expense, gross ($ millions)	**$ 81**	$ 69	$ 58	**$ 208**	$ 166
Less: capitalized interest, Horizon Project	**$ 56**	$ 41	$ 20	**$ 130**	$ 45
Interest expense, net	**$ 25**	$ 28	$ 38	**$ 78**	$ 121
$/boe(1)	**$ 0.48**	$ 0.53	$ 0.73	**$ 0.51**	$ 0.82
Average effective interest rate	**5.8%**	5.7%	6.0%	**5.8%**	5.5%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest expense increased from the comparable periods in 2005 and the prior quarter primarily due to higher debt levels. Net interest expense decreased from the comparable periods in 2005 on a total and a boe basis primarily due to the capitalization of construction period interest related to the Horizon Project.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not used for trading or speculative purposes. Changes in the fair value of derivative financial instruments designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in the fair value of derivative financial instruments not designated as hedges are recognized in the consolidated balance sheets each period with the offset reflected in risk management activities in the statement of earnings.

The Company formally documents all hedging transactions at the inception of the hedging relationship in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated both at inception of the hedge and on an ongoing basis.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. Gains or losses on these contracts are included in risk management activities.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Cross currency swap agreements are periodically used to manage interest and currency exposure on US denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Gains or losses on interest rate and cross currency swap contracts designated as hedges are included in interest expense. Gains or losses on non-designated interest rate and cross currency swap contracts are included in risk management activities.

Gains or losses on the termination or de-designation of financial instruments that have been accounted for as hedges are deferred under Other Assets or Liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged item is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in net earnings. Gains or losses on the termination of financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

RISK MANAGEMENT

($ millions)	Three Months Ended Sep 30 2006	Jun 30 2006	Sep 30 2005	Nine Months Ended Sep 30 2006	Sep 30 2005
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 419**	$ 421	$ 319	**$ 1,172**	$ 518
Natural gas financial instruments	**(15)**	(14)	49	**27**	41
Interest rate swaps	**-**	-	-	**-**	(8)
	$ 404	$ 407	$ 368	**$ 1,199**	$ 551
Unrealized (gain) loss					
Crude oil and NGLs financial instruments	**$ (601)**	$ (10)	$ 286	**$ (497)**	$ 1,361
Natural gas financial instruments	**(152)**	(12)	348	**(268)**	384
Interest rate swaps	**(1)**	(4)	(1)	**(7)**	5
	$ (754)	$ (26)	$ 633	**$ (772)**	$ 1,750
Total	**$ (350)**	$ 381	$ 1,001	**$ 427**	$ 2,301

The net realized losses (gains) from crude oil and NGLs and natural gas financial instruments decreased (increased) the Company's average realized prices as follows:

	Three Months Ended Sep 30 2006	Jun 30 2006	Sep 30 2005	Nine Months Ended Sep 30 2006	Sep 30 2005
Crude oil and NGLs ($/bbl)[1]	**$ 13.15**	$ 14.18	$ 10.69	**$ 13.15**	$ 6.31
Natural gas ($/mcf)[1]	**$ (0.11)**	$ (0.11)	$ 0.38	**$ 0.06**	$ 0.10

(1) Amounts expressed on a per unit basis are based on sales volumes.

As effective as commodity hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management liability reflects, at September 30, 2006, the implied price differentials for the non-designated hedges for future years. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at September 30, 2006. Due to changes in the crude oil and natural gas forward pricing and the settlement of a portion of 2006 contracts as at September 30, 2006, the Company recorded a net pre-tax $772 million ($508 million after-tax) unrealized gain on its risk management activities for the nine months ended September 30, 2006 (September 30, 2005 - unrealized pre-tax loss of $1,750 million), including a pre-tax $754 million ($496 million after-tax) unrealized gain for the three months ended September 30, 2006 (September 30, 2005 - unrealized pre-tax loss of $633 million; June 30, 2006 - unrealized pre-tax gain of $26 million).

In addition to the risk management liability recognized on the balance sheet at September 30, 2006, the net unrecognized asset related to the fair value of derivative financial instruments designated as hedges was $195 million at September 30, 2006 (December 31, 2005 – net unrecognized liability of $990 million).

Details related to outstanding derivative financial instruments at September 30, 2006 are disclosed in note 7 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	Three Months Ended Sep 30 2006	Jun 30 2006	Sep 30 2005	Nine Months Ended Sep 30 2006	Sep 30 2005
Realized foreign exchange loss (gain)	**$ 1**	$ **12**	$ 5	**$ 8**	$ (13)
Unrealized foreign exchange loss (gain)	**11**	**(58)**	(124)	**(37)**	(108)
	$ 12	$ **(46)**	$ (119)	**$ (29)**	$ (121)

The Company's results are affected by the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in lower revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar will result in higher revenue from the sale of the Company's production. Production expenses are subject to fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar on North Sea operations. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The realized foreign exchange loss for the nine and three months ended September 30, 2006 was primarily the result of foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. The unrealized foreign exchange loss (gain) for the three and nine months ended September 30, 2006 was related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital in North America denominated in US dollars, as well as the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. The Canadian dollar ended the third quarter at US$0.8966 compared to US$0.8613 at September 30, 2005 (June 30, 2006 - US$0.8969).

In order to mitigate a portion of the volatility associated with fluctuations in exchange rates, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in Shareholders' Equity in the consolidated balance sheets.

TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2006	Jun 30 2006	Sep 30 2005	Nine Months Ended Sep 30 2006	Sep 30 2005
Taxes other than income tax					
Current	**$ 81**	$ 59	$ 75	**$ 175**	$ 153
Deferred	**(4)**	18	(14)	**40**	(10)
	$ 77	$ 77	$ 61	**$ 215**	$ 143
Current income tax					
North America	**$ 52**	$ 22	$ 25	**$ 92**	$ 91
North Sea	**-**	(1)	57	**-**	124
Offshore West Africa	**6**	16	6	**35**	13
	$ 58	$ 37	$ 88	**$ 127**	$ 228
Future income tax expense (recovery)	**$ 473**	$ (224)	$ 18	**$ 517**	$ (161)
Effective income tax rate	**32.2%(3)**	**(21.9)%(2)**	41.3%	**22.6%(1)(2)(3)**	> 100%(4)

(1) Includes the effect of a charge of $110 million related to the increased supplementary charge on oil and gas profits in the UK North Sea, substantively enacted in the first quarter of 2006.

(2) Includes the effect of a recovery of $438 million due to Canadian Federal, Alberta and Saskatchewan corporate income tax rate reductions enacted during the second quarter.

(3) Includes the effect of a recovery of $67 million due to Côte d'Ivoire corporate income tax rate reductions enacted during the third quarter.

(4) For the nine months ended September 30, 2005, the Company's effective tax rate was greater than 100% due to the combined effects of jurisdictional tax rate differences between the various business segments, together with a nominal consolidated net earnings before taxes.

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") and Canadian provincial capital taxes. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in a subsequent year. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature and amount of capital expenditures incurred in Canada.

During the first quarter of 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production, resulting in an increase of future tax liabilities of $110 million.

During the second quarter of 2006, the Canadian Federal Government enacted reductions to its corporate income tax rates, resulting in a reduction of future income tax liabilities of approximately $277 million.

During the second quarter of 2006, the provinces of Alberta and Saskatchewan enacted reductions to their corporate income tax rates, resulting in a reduction of future tax liabilities of approximately $161 million.

During the third quarter of 2006, the Government of Côte d'Ivoire enacted reductions to its corporate income tax rates, resulting in a reduction of future income tax liabilities of approximately $67 million.

CAPITAL EXPENDITURES[1]

($ millions)	Three Months Ended Sep 30 2006	Three Months Ended Jun 30 2006	Three Months Ended Sep 30 2005	Nine Months Ended Sep 30 2006	Nine Months Ended Sep 30 2005
Expenditures on property, plant and equipment					
Net property (dispositions) acquisitions	**$ (6)**	$ 7	$ -	**$ 13**	$ (339)
Land acquisition and retention	**29**	54	69	**182**	157
Seismic evaluations	**26**	35	31	**113**	92
Well drilling, completion and equipping	**524**	418	431	**1,878**	1,371
Pipeline and production facilities	**270**	233	266	**1,003**	981
Total net reserve replacement expenditures	**843**	747	797	**3,189**	2,262
Horizon Project:					
Phase 1 construction costs[2]	**727**	680	413	**2,023**	780
Phases 2 and 3 costs	**18**	6	-	**25**	-
Capitalized interest, stock-based compensation and other[2]	**39**	96	39	**204**	162
Total Horizon Project	**784**	782	452	**2,252**	942
Midstream	**2**	6	(1)	**11**	3
Abandonments[3]	**24**	17	19	**56**	30
Head office	**8**	6	5	**20**	16
Total net capital expenditures	**$ 1,661**	$ 1,558	$ 1,272	**$ 5,528**	$ 3,253
By segment					
North America	**$ 667**	$ 569	$ 618	**$ 2,640**	$ 1,668
North Sea	**148**	149	100	**435**	269
Offshore West Africa	**27**	27	79	**104**	320
Other	**1**	2	-	**10**	5
Horizon Project	**784**	782	452	**2,252**	942
Midstream	**2**	6	(1)	**11**	3
Abandonments[3]	**24**	17	19	**56**	30
Head office	**8**	6	5	**20**	16
Total	**$ 1,661**	$ 1,558	$ 1,272	**$ 5,528**	$ 3,253

(1) Capital expenditures do not include non-cash property, plant and equipment additions or disposals.
(2) Certain prior period amounts have been reclassified with respect to stock-based compensation costs.
(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company focuses its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures in the nine months ended September 30, 2006 were $5,528 million compared to $3,253 million in the nine months ended September 30, 2005. The increase was primarily related to higher capital expenditures on the Horizon Project, a focus on natural gas drilling in Northeast British Columbia and Northwest Alberta and general inflationary pressures. The increase also reflects $339 million in net property dispositions in 2005. In the nine months ended September 30, 2006, the Company drilled a total of 1,407 net wells consisting of 581 natural gas wells, 426 crude oil wells, 309 stratigraphic test and service wells, and 91 wells that were dry. The 309 stratigraphic test and service wells include 103 stratigraphic test wells related to the Horizon Project. This compared to 1,357 net wells drilled in the nine months ended September 30, 2005. The Company achieved an overall success rate of 92% for the nine months ended September 30, 2006, excluding stratigraphic test and service wells (September 30, 2005 - 92%).

Net capital expenditures in the third quarter of 2006 were $1,661 million compared to $1,272 million in the comparable period in 2005 and $1,558 million in the prior quarter. The increase from the third quarter of 2005 was primarily related to capital expenditures on the Horizon Project, and increased costs associated with natural gas drilling related to the North America conventional operations. In the third quarter of 2006, the Company drilled a total of 376 net wells consisting of 98 natural gas wells, 255 crude oil wells and 23 wells that were dry. The Company achieved an overall success rate of 94% for the third quarter of 2006, excluding stratigraphic test and service wells.

North America

North America (including the Horizon Project) accounted for approximately 90% of the total capital expenditures for the nine months ended September 30, 2006 compared to approximately 82% in the comparable period in 2005.

During the first nine months of 2006, the Company targeted 658 net natural gas wells, including 202 wells in Northeast British Columbia, 235 wells in the Northern Plains region, 124 wells in Northwest Alberta, and 97 wells in the Southern Plains region. The Company also targeted 431 net crude oil wells during the first nine months. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 182 heavy crude oil wells, 105 Pelican Lake crude oil wells, and 6 light crude oil wells were drilled. Another 95 wells targeting light crude oil were drilled outside the Northern Plains as well as 43 thermal crude oil wells in the Company's Insitu Oil Sands area. In the third quarter of 2006, the Company drilled 111 net wells targeting natural gas and 263 net wells targeting crude oil.

Due to significant changes in relative commodity prices between crude oil and natural gas, the Company has taken the opportunity to utilize its large drilling inventory to maximize value in both the short and long term. While natural gas pricing has softened significantly in 2006, crude oil pricing remains strong. Related production expenses for both commodities continue to reflect industry wide inflationary cost pressures. Accordingly, to optimize netbacks in the near term, the Company will continue to focus on drilling crude oil wells and will reduce natural gas drilling activity for the balance of 2006. Deferred natural gas wells will be retained in the Company's prospect inventory, and will be drilled as natural gas commodity prices improve. ACC drilling in the fourth quarter will also be optimized as part of the acquisition.

As part of the development of the Company's Insitu Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. At the end of the third quarter, the Company had drilled 183 stratigraphic test wells, and had drilled 43 thermal oil wells. First steaming for the Primrose North expansion project commenced in November 2005, resulting in production of approximately 23,000 bbl/d in September 2006. Overall Primrose thermal production for the nine months ended September 30, 2006 increased to approximately 60,000 bbl/d from 50,000 bbl/d for the comparable period in 2005.

In November of 2005, the Company announced a phased expansion of its Insitu Oil Sands Assets. The next phase of this development is the Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility. This phase of the expansion is anticipated to add an additional 30,000 bbl/d and received Board sanction in the third quarter of 2006. Detailed engineering and procurement is currently underway. The Company anticipates regulatory approval for Primrose East in the first quarter of 2007, with drilling and construction to begin in the second quarter of 2007, and first production commencing in 2009.

Development of new acreage and secondary recovery conversion projects at Pelican Lake continued as expected through the third quarter of 2006. Drilling consisted of 46 horizontal wells, with plans to drill 44 additional horizontal wells over the remainder of the year. The pressure response from the polymer flood pilot continued to be positive. Based on the results of the pilot, the Company commenced installation of a further four polymer skids as part of the commercial polymer flood project. Pelican Lake production averaged approximately 30,000 bbl/d for the third quarter of 2006.

In the fourth quarter of 2006, the Company's overall drilling activity in North America is expected to be comprised of 82 natural gas wells and 224 crude oil wells excluding stratigraphic and service wells.

Horizon Oil Sands Project

The Horizon Project continued on schedule and on budget with construction 47% complete at quarter end. The project status as at September 30, 2006 was as follows:

- Completed 90% of model reviews;
- Awarded total contracts and purchase orders in excess of $4.8 billion, with a further $200 million in various stages of the tender process;
- Awarded several key mechanical contracts;
- Set 295 piperack modules for total progress of 63% complete; and
- Site preparation and underground infrastructure completed.

Major activities for the fourth quarter of 2006 will include;

- Complete the construction of Mechanically Stabilized Earth Shear Wall in the Ore Preparation Plant; and
- Commence installation of Primary Upgrading large bore piping.

First production of light, sweet Synthetic Crude Oil from Phase 1 construction is targeted to commence in the second half of 2008.

North Sea

In the third quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the quarter, 1.0 net wells were drilled, with an additional 2.5 net wells drilling at quarter end.

The development of the Lyell Field progressed during the third quarter. The Lyell Field development comprises the drilling of four net wells, including one injector, and the workover of two existing wells in 2006 and 2007. At its peak, new production of approximately 20,000 boe/d is forecast from the Field. The Columba E Raw Water Injection project progressed during the third quarter.

Offshore West Africa

First oil from West Espoir commenced during the third quarter at a peak rate of approximately 5,000 bbl/d net to the Company. The West Espoir area development drilling will continue until 2008 with producers and injectors being brought on-line as they are completed.

The Company purchased a 90% interest in the Olowi PSC offshore Gabon in October 2005 and received approval of its development plan for this acquisition during the first quarter of 2006. Development plans include a floating production, storage and offtake vessel ("FPSO"), handling input from three or four shallow-water producing platforms. During the third quarter of 2006 evaluation of key tenders continued, together with engineering studies and optimization of project planning.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Pro Forma Sep 30 2006**[1]	**Sep 30 2006**	Jun 30 2006	Dec 31 2005	Sep 30 2005
Working capital deficit[2]	**n/a**	**$ 1,032**	$ 1,554	$ 1,774	$ 2,106
Long-term debt	**$ 10,040**	**$ 5,500**	$ 5,004	$ 3,321	$ 3,235
Shareholders' equity					
Share capital	**$ 2,536**	**$ 2,536**	$ 2,516	$ 2,442	$ 2,433
Retained earnings	**7,869**	**7,869**	6,798	5,804	4,759
Foreign currency translation adjustment	**(12)**	**(12)**	(12)	(9)	(11)
Total	**$ 10,393**	**$ 10,393**	$ 9,302	$ 8,237	$ 7,181
Debt to cash flow[3]	**n/a**	**1.1x**	1.0x	0.7x	0.8x
Debt to EBITDA[4]	**n/a**	**1.0x**	0.9x	0.6x	0.7x
Debt to book capitalization[5]	**49.1%**	**34.6%**	35.0%	28.7%	32.3%
Debt to market capitalization	**26.8%**	**16.7%**	13.1%	9.7%	10.8%
After tax return on average common shareholders' equity[6]	**n/a**	**38.2%**	29.3%	14.3%	7.4%
After tax return on average capital employed[7]	**n/a**	**26.0%**	20.2%	10.4%	5.8%

(1) Refer to note 10 of the consolidated financial statements, Acquisition of Anadarko Canada Corporation. Pro forma financial information is based on aggregate consideration of US$4.075 billion, before working capital and other adjustments, converted to Canadian dollars using an estimated exchange rate of 0.8975. N/a means the relevant ACC information is not available.

(2) Calculated as current assets less current liabilities.

(3) Calculated as current and long-term debt; divided by cash flow from operations for the twelve month trailing period.

(4) Calculated as current and long-term debt; divided by earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities for the twelve month trailing period.

(5) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

(6) Calculated as net earnings for the twelve month trailing period as a percentage of average common shareholders' equity for the period.

(7) Calculated as net earnings plus after-tax interest expense for the twelve month trailing period; as a percentage of average capital employed for the period. Average capital employed is the average shareholders' equity and current and long-term debt for the period.

The Company's capital resources at September 30, 2006 consisted primarily of cash flow from operations, available credit facilities and access to capital markets. Cash flow from operations is dependent on factors discussed in the Risks and Uncertainties section of the Company's December 31, 2005 annual MD&A. The Company's ability to renew existing credit facilities and raise new debt is dependent upon these factors, maintaining an investment grade debt rating and the condition of capital and credit markets. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its five- and ten-year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt, will be sufficient to sustain its operations and support its growth strategy.

At September 30, 2006, the Company had undrawn bank lines of credit of $2,185 million. These credit lines are supported by credit facilities, which if not extended, mature in 2011.

At September 30, 2006, the working capital deficit was $1,032 million and included the current portion of other long-term liabilities of $541 million, comprised of stock-based compensation of $414 million and the mark-to-market valuation of non-designated risk management financial derivative instruments of $127 million. The repayment of the stock-based compensation liability is dependant upon both the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at September 30, 2006.

The Company is committed to maintaining a strong financial position. In the third quarter of 2006, strong operational results and high crude oil prices resulted in a debt to book capitalization level of 34.6%. The Company believes it has the necessary financial capacity to complete the Horizon Project, while at the same time not compromising conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet. Existing proved development projects, which have largely been funded prior to September 30, 2006, such as Baobab, Primrose and West Espoir, and the acquisition of ACC, are anticipated to provide identified growth in production volumes in 2006 through 2008, and generate incremental free cash flows during this period.

The Company believes that its balance sheet has the strength and flexibility to accommodate the ACC acquisition. To ensure balance sheet strength going forward, the Company has hedged a significant portion of its natural gas and crude oil production for 2007 and 2008 at prices that protect investment returns. The Company may also consider the divestiture of non-strategic and non-core properties to gain additional balance sheet flexibility.

In addition to the strategic location of the high quality assets that ACC brings to the Company, this acquisition allows the Company to further high grade its project inventory and significantly reduce capital expenditures in the current highly inflationary service market. The Company has, as a result of the acquisition, reduced its 2007 conventional crude oil and natural gas capital budget by $900 million compared to 2006 capital spending, while maintaining the capital expenditures to complete Phase I of the Horizon Project.

During the third quarter of 2006, in anticipation of the acquisition of ACC, the Board of Directors amended the Company's commodity hedging program. The commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditure program throughout the Horizon Project construction period. This program was temporarily amended to allow for the hedging of up to 75% of the expected production to the end of 2007 and up to 50% of the expected 2008 production through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 60% of expected crude oil volumes and approximately 70% of expected natural gas volumes have been hedged for the remainder of 2006 and 2007. In 2007 the Company will revert to the original hedging program which allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48.

Long-term debt

Long-term debt as at September 30, 2006 was $5,500 million. The debt to EBITDA ratio was 1.0x (June 30, 2006 - 0.9x; December 31, 2005 - 0.6x; September 30, 2005 - 0.7x) and the debt to book capitalization was 34.6% (June 30, 2006 – 35.0%; December 31, 2005 - 28.7%; September 30, 2005 – 32.3%) as at September 30, 2006. At September 30, 2006, these ratios were below the Company's guidelines for balance sheet management of debt to EBITDA of 1.8x to 2.2x and debt to book capitalization of 35% to 45%.

Bank Credit facilities

As at September 30, 2006, the Company had in place unsecured bank credit facilities of $3,456 million, comprised of:

- a $100 million operating demand credit facility;
- a 5-year revolving syndicated credit and term loan facility of $1,825 million;
- a 5-year revolving syndicated credit and term loan facility of $1,500 million; and
- a £15 million demand overdraft credit facility related to the Company's North Sea operations.

During the second quarter, the syndicated revolving credit and term loan facilities were renegotiated and are fully revolving for a period of five years maturing June 2011. Both facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

In conjunction with the closing of the acquisition of ACC, the Company expects to execute a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. This facility is subject to certain prepayment requirements up to a maximum of $1,500 million.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $571 million, including a $453 million deposit related to the acquisition of ACC, were outstanding at September 30, 2006. Subsequent to quarter end, an additional $210 million of financial guarantees related to the Horizon Project were issued.

Medium-term notes

In January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

US dollar debt securities

In August 2006, the Company issued US$250 million of unsecured notes maturing August 2016 and US$450 million of unsecured notes maturing February 2037, bearing interest at 6.00% and 6.50%, respectively. Concurrently, the Company entered into cross-currency interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on the US$250 million notes at 5.40% and C$279 million. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has US$1.3 billion remaining on its US$2 billion short form prospectus filed in June 2005 that allows for the issue of debt securities in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

Share capital

As at September 30, 2006, there were 537,447,000 common shares and 29,281,000 stock options outstanding. As at October 27, 2006, the Company had 537,499,000 common shares outstanding.

In January 2006, the Company announced the renewal of its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2006 and ending January 23, 2007, up to 26,852,545 common shares or 5% of the common shares of the Company then outstanding on the date of the announcement. As at September 30, 2006, the Company had purchased 485,000 common shares at an average price of $57.33 per common share, for a total cost of $28 million. No shares were repurchased subsequent to September 30, 2006.

In February 2006, the Board of Directors set the regular quarterly dividend at $0.075 per common share (2005 - $0.059 per common share). The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Contractual obligations

In the normal course of business, the Company has entered into various contractual arrangements and commitments that will have an impact on the Company's future operations. These contractual obligations and commitments primarily relate to debt repayments, operating leases relating to office space and offshore production and storage vessels, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. As at September 30, 2006, no entities have been consolidated under CICA HB AcG-15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at September 30, 2006:

($ millions)	Remaining 2006	2007	2008	2009	2010	Thereafter
Product transportation and pipeline(1)	$ 69	$ 184	$ 181	$ 128	$ 116	$ 1,117
Offshore equipment operating lease	$ 12	$ 49	$ 49	$ 49	$ 49	$ 171
Offshore drilling	$ 32	$ 167	$ 75	$ 11	$ 11	$ 4
Asset retirement obligations(2)(5)	$ 25	$ 4	$ 4	$ 4	$ 7	$ 3,363
Long-term debt(3)	$ -	$ 160	$ 35	$ 35	$ -	$ 4,033
Other(4)(5)	$ 20	$ 68	$ 29	$ 37	$ 39	$ 21

(1) In 2005, the Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.

(2) Represents management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices.

(3) The long-term debt represents principal repayments only. No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.

(4) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

(5) No provision for ACC related amounts have been included.

In February 2005, the Board of Directors approved the construction costs for Phase 1 of the Horizon Project, which are budgeted to be $6.8 billion, with cumulative spending of $3.3 billion to September 30, 2006, $0.6 billion targeted to be incurred in the remainder of 2006 and $2.9 billion targeted to be incurred in 2007 and 2008.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Critical accounting estimates

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2005.

PRO FORMA SENSITIVITY ANALYSIS[(1)]

The following table is a representation of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and production volumes during the third quarter of 2006, and is not necessarily indicative of future results. Actual results will differ and these differences may be material. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl[(2)]				
Excluding financial derivatives	$ 110	$ 0.21	$ 78	$ 0.14
Including financial derivatives	$ 94	$ 0.17	$ 66	$ 0.12
Natural gas – AECO C$0.10/mcf[(2)]				
Excluding financial derivatives	$ 27	$ 0.05	$ 13	$ 0.02
Including financial derivatives	$ 3	$ 0.00	$ 0	$ 0.00
Volume changes				
Crude oil – 10,000 bbl/d	$ 137	$ 0.25	$ 76	$ 0.14
Natural gas – 10 mmcf/d	$ 14	$ 0.03	$ 5	$ 0.01
Foreign currency rate change				
$0.01 change in C$ in relation to US$[(2)]	$ 80-82	$ 0.15	$ 25-26	$ 0.05
Interest rate change - 1%[(3)]	$ 43	$ 0.08	$ 43	$ 0.08

(1) The sensitivities are calculated based on 2006 third quarter results including the anticipated effects of the expected acquisition of ACC and excluding mark-to-market gains (losses) on risk management activities.

(2) For details of outstanding financial instruments in place, refer to note 7 of the Company's unaudited interim consolidated financial statements.

(3) Pro forma financial information is based on aggregate consideration of US $4.075 billion, before working capital and other adjustments.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

($/boe)[1]	Three Months Ended Sep 30 2006	Three Months Ended Jun 30 2006	Three Months Ended Sep 30 2005	Nine Months Ended Sep 30 2006	Nine Months Ended Sep 30 2005
Sales price[2]	**$ 51.21**	$ 50.36	$ 54.87	**$ 49.38**	$ 46.17
Royalties	**5.75**	5.80	7.84	**5.99**	6.40
Production expense[3]	**10.01**	8.85	8.56	**9.13**	8.31
Netback	**35.45**	35.71	38.47	**34.26**	31.46
Midstream contribution[3]	**(0.23)**	(0.23)	(0.26)	**(0.24)**	(0.27)
Administration	**0.76**	0.78	0.75	**0.79**	0.78
Interest, net	**0.48**	0.53	0.73	**0.51**	0.82
Realized risk management loss	**7.51**	7.81	7.12	**7.73**	3.73
Realized foreign exchange loss (gain)	**0.01**	0.25	0.10	**0.05**	(0.09)
Taxes other than income tax - current	**1.50**	1.13	1.46	**1.13**	1.04
Current income tax - North America	**0.97**	0.42	0.46	**0.60**	0.61
Current income tax - North Sea	**-**	(0.01)	1.11	**-**	0.84
Current income tax - Offshore West Africa	**0.11**	0.30	0.12	**0.22**	0.09
Cash flow	**$ 24.34**	$ 24.73	$ 26.88	**$ 23.47**	$ 23.91

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Including transportation costs and excluding risk management activities.

(3) Excluding intersegment elimination.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	**Sep 30 2006**	Dec 31 2005
ASSETS		
Current assets		
Cash and cash equivalents	**$ 12**	$ 18
Accounts receivable and other	**1,430**	1,546
Future income tax	**182**	487
	1,624	2,051
Property, plant and equipment (note 9)	**23,447**	19,694
Other long-term assets	**129**	107
	$ 25,200	$ 21,852
LIABILITIES		
Current liabilities		
Accounts payable	**$ 772**	$ 573
Accrued liabilities	**1,343**	1,781
Current portion of other long-term liabilities (note 3)	**541**	1,471
	2,656	3,825
Long-term debt (note 2)	**5,500**	3,321
Other long-term liabilities (note 3)	**1,340**	1,434
Future income tax	**5,311**	5,035
	14,807	13,615
SHAREHOLDERS' EQUITY		
Share capital (note 5)	**2,536**	2,442
Retained earnings	**7,869**	5,804
Foreign currency translation adjustment	**(12)**	(9)
	10,393	8,237
	$ 25,200	$ 21,852

Commitments (note 8)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Sep 30 2006**	Sep 30 2005	Nine Months Ended **Sep 30 2006**	Sep 30 2005
Revenue	**$ 2,859**	$ 2,918	**$ 7,948**	$ 7,075
Less: royalties	**(310)**	(403)	**(928)**	(945)
Revenue, net of royalties	**2,549**	2,515	**7,020**	6,130
Expenses				
Production	**544**	446	**1,430**	1,240
Transportation	**82**	71	**241**	204
Depletion, depreciation and amortization	**589**	505	**1,667**	1,463
Asset retirement obligation accretion (note 3)	**17**	18	**50**	53
Administration	**41**	38	**123**	115
Stock-based compensation (recovery) expense (note 3)	**(135)**	199	**(37)**	598
Interest, net	**25**	38	**78**	121
Risk management activities (note 7)	**(350)**	1,001	**427**	2,301
Foreign exchange loss (gain)	**12**	(119)	**(29)**	(121)
	825	2,197	**3,950**	5,974
Earnings before taxes	**1,724**	318	**3,070**	156
Taxes other than income tax	**77**	61	**215**	143
Current income tax expense (note 4)	**58**	88	**127**	228
Future income tax expense (recovery) (note 4)	**473**	18	**517**	(161)
Net earnings (loss)	**$ 1,116**	$ 151	**$ 2,211**	$ (54)
Net earnings (loss) per common share (note 6)				
Basic and diluted	**$ 2.08**	$ 0.28	**$ 4.12**	$ (0.10)

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Nine Months Ended **Sep 30 2006**	Sep 30 2005
Balance – beginning of period	**$ 5,804**	$ 4,922
Net earnings (loss)	**2,211**	(54)
Dividends on common shares (note 5)	**(120)**	(94)
Purchase of common shares under normal course issuer bid (note 5)	**(26)**	(15)
Balance – end of period	**$ 7,869**	$ 4,759

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Sep 30 2006**	Three Months Ended Sep 30 2005	Nine Months Ended **Sep 30 2006**	Nine Months Ended Sep 30 2005
Operating activities				
Net earnings (loss)	**$ 1,116**	$ 151	**$ 2,211**	$ (54)
Non-cash items				
Depletion, depreciation and amortization	**589**	505	**1,667**	1,463
Asset retirement obligation accretion	**17**	18	**50**	53
Stock-based compensation (recovery) expense	**(135)**	199	**(37)**	598
Unrealized risk management activities	**(754)**	633	**(772)**	1,750
Unrealized foreign exchange loss (gain)	**11**	(124)	**(37)**	(108)
Deferred petroleum revenue tax (recovery)	**(4)**	(14)	**40**	(10)
Future income tax expense (recovery)	**473**	18	**517**	(161)
Deferred charges	**-**	5	**(8)**	(33)
Abandonment expenditures	**(24)**	(19)	**(56)**	(30)
Net change in non-cash working capital	**(4)**	8	**(362)**	(79)
	1,285	1,380	**3,213**	3,389
Financing activities				
(Repayment) issue of bankers' acceptances	**(285)**	(168)	**1,115**	(509)
Issue of medium-term notes	**-**	-	**400**	400
Issue of US dollar debt securities	**788**	-	**788**	-
Issue of common shares on exercise of stock options	**4**	1	**17**	6
Repayment of preferred securities	**-**	(107)	**-**	(107)
Dividends on common shares	**(41)**	(32)	**(113)**	(89)
Purchase of common shares	**(6)**	(16)	**(28)**	(16)
Net change in non-cash working capital	**2**	(4)	**8**	16
	462	(326)	**2,187**	(299)
Investing activities				
Expenditures on property, plant and equipment	**(1,638)**	(1,258)	**(5,475)**	(3,576)
Net proceeds on sale of property, plant and equipment	**1**	5	**3**	353
Net expenditures on property, plant and equipment	**(1,637)**	(1,253)	**(5,472)**	(3,223)
Investment in other assets	**-**	71	**-**	11
Net change in non-cash working capital	**(113)**	109	**66**	106
	(1,750)	(1,073)	**(5,406)**	(3,106)
Decrease in cash	**(3)**	(19)	**(6)**	(16)
Cash – beginning of period	**15**	31	**18**	28
Cash – end of period	**$ 12**	$ 12	**$ 12**	$ 12
Interest paid	**$ 70**	$ 61	**$ 179**	$ 152
Taxes paid				
Taxes other than income tax	**$ 106**	$ 12	**$ 239**	$ 171
Current income tax	**$ 51**	$ 69	**$ 304**	$ 192

Notes to the consolidated financial statements (tabular amounts in millions of Canadian dollars, unaudited)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2005. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2005.

2. LONG–TERM DEBT

	Sep 30 2006	Dec 31 2005
Bank credit facilities		
Bankers' acceptances	**$ 1,237**	$ 122
Medium-term notes	**925**	525
Senior unsecured notes (2006 and 2005 – US$93 million)	**104**	108
US dollar debt securities (2006 – US$2,900; and 2005 – US$2,200 million)	**3,234**	2,566
	$ 5,500	$ 3,321

Bank credit facilities

As at September 30, 2006, the Company had in place unsecured bank credit facilities of $3,456 million, comprised of:

- a $100 million operating demand credit facility;
- a 5-year revolving syndicated credit and term loan facility of $1,825 million;
- a 5-year revolving syndicated credit and term loan facility of $1,500 million; and
- a £15 million demand overdraft credit facility related to the Company's North Sea operations.

During the second quarter, the syndicated revolving credit and term loan facilities were renegotiated and are fully revolving for a period of five years maturing June 2011. Both facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

In conjunction with the closing of the acquisition of Anadarko Canada Corporation ("ACC") (note 10), the Company expects to execute a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. This facility is subject to certain prepayment requirements up to a maximum of $1,500 million.

The weighted average interest rate of the bank credit facilities outstanding at September 30, 2006, was 4.8% (December 31, 2005 - 4.0%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $571 million, including $453 million related to the acquisition of ACC, were outstanding at September 30, 2006. Subsequent to September 30, 2006, an additional $210 million of financial guarantees related to the Horizon Project were issued.

Medium-term notes

In January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

US dollar debt securities

In August 2006, the Company issued US$250 million of unsecured notes maturing August 2016 and US$450 million of unsecured notes maturing February 2037, bearing interest at 6.00% and 6.50%, respectively. Concurrently, the Company entered into cross-currency interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on the US$250 million notes at 5.40% and C$279 million (note 7). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has US$1.3 billion remaining on its US$2 billion short form prospectus filed in June 2005 that allows for the issue of debt securities in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

3. OTHER LONG–TERM LIABILITIES

	Sep 30 2006	Dec 31 2005
Asset retirement obligations	**$ 1,108**	$ 1,112
Stock-based compensation	**597**	891
Risk management (note 7)	**127**	885
Other	**49**	17
	1,881	2,905
Less: current portion	**541**	1,471
	$ 1,340	$ 1,434

Asset retirement obligations

At September 30, 2006, the Company's total estimated undiscounted cost to settle its asset retirement obligations was approximately $3,407 million (December 31, 2005 - $3,325 million). These costs will be incurred over the lives of the operating assets and have been discounted using an average credit-adjusted risk free rate of 6.8%. A reconciliation of the discounted asset retirement obligations is as follows:

	Nine Months Ended Sep 30, 2006	Year Ended Dec 31, 2005
Balance – beginning of period	**$ 1,112**	$ 1,119
Liabilities incurred	**24**	47
Liabilities settled	**(56)**	(46)
Asset retirement obligation accretion	**50**	69
Revision of estimates	**1**	(56)
Foreign exchange	**(23)**	(21)
Balance – end of period	**$ 1,108**	$ 1,112

The Company's pipelines have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligations for these assets will be recorded in the years in which the lives of the assets are determinable.

Stock-based compensation

The Company recognizes a liability for the potential cash settlements under its Stock Option Plan. The current portion represents the maximum amount of the liability payable within the next 12-month period if all vested options are surrendered for cash settlement.

	Nine Months Ended Sep 30, 2006	Year Ended Dec 31, 2005
Balance – beginning of period	**$ 891**	$ 323
Stock-based compensation (recovery) expense	**(37)**	723
Current period payment for options surrendered	**(216)**	(227)
Transferred to common shares	**(79)**	(29)
Capitalized to Horizon Project	**38**	101
Balance – end of period	**597**	891
Less: current portion of stock-based compensation	**414**	629
	$ 183	$ 262

4. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Current income tax – North America	**$ 52**	$ 25	**$ 92**	$ 91
Current income tax – North Sea	**-**	57	**-**	124
Current income tax – Offshore West Africa	**6**	6	**35**	13
Current income tax expense	**58**	88	**127**	228
Future income tax expense (recovery)	**473**	18	**517**	(161)
Income tax expense	**$ 531**	$ 106	**$ 644**	$ 67

A significant portion of the Company's North America taxable income is generated through partnerships. Current income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings. North America current income tax is dependant upon the nature and amount of capital expenditures incurred in Canada.

During the first quarter of 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production, resulting in an increase of future tax liabilities of $110 million.

During the second quarter of 2006, the Canadian Federal Government enacted reductions to its corporate income tax rates, resulting in a reduction of future income tax liabilities of approximately $277 million.

During the second quarter of 2006, the provinces of Alberta and Saskatchewan enacted reductions to their corporate income tax rates, resulting in a reduction of future tax liabilities of approximately $161 million.

During the third quarter of 2006, the Government of Côte d'Ivoire enacted reductions to its corporate income tax rates, resulting in a reduction of future income tax liabilities of approximately $67 million.

5. SHARE CAPITAL

	Nine Months Ended Sep 30, 2006	
Issued **Common shares**	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**536,348**	**$ 2,442**
Issued upon exercise of stock options	**1,584**	**17**
Previously recognized liability on stock options exercised for common shares	**-**	**79**
Purchase of common shares under Normal Course Issuer Bid	**(485)**	**(2)**
Balance – end of period	**537,447**	**$ 2,536**

Normal course issuer bid

In January 2006, the Company announced the renewal of its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2006 and ending January 23, 2007, up to 26,852,545 common shares or 5% of the common shares of the Company then outstanding on the date of the announcement. As at September 30, 2006, the Company had purchased 485,000 common shares at an average price of $57.33 per common share, for a total cost of $28 million. Retained earnings was reduced by $26 million, representing the excess of the purchase price of the common shares over their stated value. No shares were repurchased subsequent to September 30, 2006.

Dividend policy

In February 2006, the Board of Directors set the regular quarterly dividend at $0.075 per common share (2005 - $0.059 per common share). The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Stock options

	Nine Months Ended Sep 30, 2006		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**30,510**	**$**	**17.79**
Granted	**5,812**	**$**	**59.69**
Exercised for common shares	**(1,584)**	**$**	**10.70**
Surrendered for cash settlement	**(4,143)**	**$**	**12.60**
Forfeited	**(1,314)**	**$**	**33.38**
Outstanding – end of period	**29,281**	**$**	**26.52**
Exercisable – end of period	**9,864**	**$**	**14.05**

6. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Weighted average common shares outstanding (thousands)				
Basic	**537,292**	536,958	**537,296**	536,688
Assumed settlement of preferred securities with common shares[1]	**-**	1,845	**-**	-
Diluted	**537,292**	538,803	**537,296**	536,688
Net earnings (loss)	**$ 1,116**	$ 151	**$ 2,211**	$ (54)
Interest on preferred securities, net of tax[1]	**-**	1	**-**	-
Revaluation on preferred securities, net of tax[1]	**-**	(3)	**-**	-
Diluted net earnings (loss)	**$ 1,116**	$ 149	**$ 2,211**	$ (54)
Net earnings (loss) per common share				
Basic	**$ 2.08**	$ 0.28	**$ 4.12**	$ (0.10)
Diluted	**$ 2.08**	$ 0.28	**$ 4.12**	$ (0.10)

(1) Preferred securities were not dilutive for the nine months ended September 30, 2005. These preferred securities were redeemed in September 2005.

7. FINANCIAL INSTRUMENTS

Risk management

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes.

The estimated fair values of non-designated financial derivatives were comprised as follows:

	Nine Months Ended Sep 30, 2006		Year Ended Dec 31, 2005	
Asset (liability)	**Risk management mark-to-market**	**Deferred revenue**	Risk management mark-to-market	Deferred revenue
Balance – beginning of period	**$ (877)**	**$ (8)**	$ 66	$ (26)
Net cost of outstanding put options	**440**	**-**	190	-
Net change in fair value of outstanding derivative financial instruments	**765**	**-**	(943)	-
Amortization of deferred revenue	**-**	**7**	-	18
	328	**(1)**	(687)	(8)
Add: Put premium financing obligations[(1)]	**(440)**	**-**	(190)	-
Balance – end of period	**(112)**	**(1)**	(877)	(8)
Less: current portion	**126**	**1**	834	8
	$ 14	**$ -**	$ (43)	$ -

(1) The Company has negotiated payment of put option premiums with various counter-parties at the time of actual settlement of the respective options. These obligations have been reflected in the risk management liability.

Net losses (gains) from risk management activities for the periods ended September 30 were as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2006	Sep 30 2005	**Sep 30 2006**	Sep 30 2005
Net realized risk management loss	**$ 404**	$ 368	**$ 1,199**	$ 551
Net unrealized risk management mark-to-market (gain) loss	**(754)**	633	**(772)**	1,750
	$ (350)	$ 1,001	**$ 427**	$ 2,301

As at September 30, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $195 million (December 31, 2005 – net unrecognized liability of $990 million).

The Company had the following net financial derivatives outstanding as at September 30, 2006:

	Remaining term			Volume	Average price			Index
Crude oil								
Price collars[1]	Oct 2006	–	Dec 2006	160,000 bbl/d	US$38.17	–	US$48.16	WTI
	Oct 2006	–	Dec 2006	90,000 bbl/d	US$45.00	–	US$77.93	WTI
	Oct 2006	–	Dec 2006	22,000 bbl/d	C$46.53	–	C$58.67	WTI
	Oct 2006	–	Dec 2007	15,000 bbl/d	US$50.00	–	US$66.25	Maya
	Jan 2007	–	Dec 2007	50,000 bbl/d	US$60.00	–	US$90.63	WTI
	Jan 2007	–	Dec 2007	50,000 bbl/d	US$65.00	–	US$84.52	WTI
Put options	Oct 2006	–	Dec 2006	51,000 bbl/d			US$50.00	WTI
	Jan 2007	–	Dec 2007	100,000 bbl/d			US$45.00	WTI
	Jan 2007	–	Dec 2007	100,000 bbl/d			US$60.00	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
Brent differential swaps	Oct 2006	–	Dec 2006	25,000 bbl/d			US$1.29	WTI/Dated Brent
	Jan 2007	–	Dec 2007	50,000 bbl/d			US$1.34	WTI/Dated Brent

(1) Subsequent to September 30, 2006, the Company entered into 50,000 bbl/d of US$60.00 – US$71.49 WTI collars for the period January 2007 to December 2007.

The cost of outstanding put options and their respective periods of settlement are as follows:

	Q4 2006	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Cost ($ millions)	US$5	US$82	US$83	US$83	US$83	US$14	US$15	US$15	US$15

	Remaining term			Volume	Average price			Index
Natural gas								
AECO collars[(1)]	Oct 2006	–	Oct 2006	300,000 GJ/d	C$5.00	–	C$7.10	AECO
	Oct 2006	–	Oct 2006	555,000 GJ/d	C$5.50	–	C$7.09	AECO
	Oct 2006	–	Oct 2006	150,000 GJ/d	C$6.00	–	C$9.53	AECO
	Oct 2006	–	Dec 2006	100,000 GJ/d	C$7.00	–	C$14.16	AECO
	Nov 2006	–	Mar 2007	300,000 GJ/d	C$7.50	–	C$18.77	AECO
	Nov 2006	–	Mar 2007	325,000 GJ/d[(2)]	C$6.00	–	C$14.68	AECO
	Nov 2006	–	Mar 2007	100,000 GJ/d	C$7.00	–	C$11.63	AECO
	Nov 2006	-	Mar 2007	400,000 GJ/d	C$8.50	–	C$11.22	AECO
	Jan 2007	-	Dec 2007	60,000 GJ/d	C$8.00	–	C$8.79	AECO
	Apr 2007	–	Oct 2007	500,000 GJ/d	C$6.00	–	C$10.13	AECO
	Apr 2007	–	Oct 2007	500,000 GJ/d	C$7.00	–	C$8.24	AECO
	Nov 2007	–	Mar 2008	500,000 GJ/d	C$6.00	–	C$16.39	AECO
	Nov 2007	–	Mar 2008	400,000 GJ/d	C$7.00	–	C$14.08	AECO

(1) Subsequent to September 30, 2006, the Company entered into 200,000 GJ/d of C$7.25 – C$8.38 AECO collars for the period January 2007 to March 2007.

(2) Subsequent to September 30, 2006, the Company unwound 260,000 GJ/d of C$6.00 – C$14.68 AECO collars for the period November 2006 to March 2007 and entered into 140,000 GJ/d of C$7.25 – C$9.48 AECO collars for the period January 2007 to March 2007 and 120,000 GJ/d of C$7.50 – C$8.91 AECO collars for the period January 2007 to March 2007.

The Company's outstanding financial derivatives will be settled monthly based on the applicable index pricing for the respective contract month.

The Company has also entered into natural gas physical sales contracts for 325,000 GJ/d at an average fixed price of C$9.17 per GJ at AECO for the period January to March 2007. Subsequent to September 30, 2006, the Company entered into natural gas physical sales contracts for 300,000 GJ/d at an average fixed price of C$7.33 per GJ at AECO for the period April 2007 to October 2007.

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Oct 2006	–	Oct 2012	US$350	5.45%	LIBOR(1) + 0.81%
	Oct 2006	–	Dec 2014	US$350	4.90%	LIBOR(1) + 0.38%
Swaps – floating to fixed	Oct 2006	–	Mar 2007	C$2	7.36%	CDOR(2)

(1) London Interbank Offered Rate

(2) Canadian Deposit Overnight Rate

	Remaining term			Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Currency							
Swaps	Oct 2006	–	Aug 2016	US$250	1.116	6.00%	5.40%
Forwards(1)	Oct 2006	–	Oct 2006	US$3,800	1.114	-	-

(1) As at September 30, 2006, the Company had fixed the Canadian dollar equivalent of US$3.8 billion of the ACC share purchase price through the use of US dollar currency forwards.

8. COMMITMENTS

The Company has committed to certain payments as follows:

		Remaining 2006		2007		2008		2009		2010		Thereafter
Product transportation and pipeline(1)	$	69	$	184	$	181	$	128	$	116	$	1,117
Offshore equipment operating lease	$	12	$	49	$	49	$	49	$	49	$	171
Offshore drilling	$	32	$	167	$	75	$	11	$	11	$	4
Asset retirement obligations(2)	$	25	$	4	$	4	$	4	$	7	$	3,363
Other(3)	$	20	$	68	$	29	$	37	$	39	$	21

(1) The Company has entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, the annual toll payments before operating costs will be approximately $35 million.

(2) Represents management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices.

(3) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

In February 2005, the Board of Directors approved the construction costs for Phase 1 of the Horizon Project, which are budgeted to be $6.8 billion, with cumulative spending of $3.3 billion to September 30, 2006, $0.6 billion targeted to be incurred in the remainder of 2006 and $2.9 billion targeted to be incurred in 2007 and 2008.

9. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore West Africa			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Segmented revenue	**2,052**	2,293	**5,954**	5,556	**567**	513	**1,264**	1,288	**236**	104	**718**	205
Less: royalties	**(293)**	(399)	**(898)**	(937)	**(1)**	(1)	**(2)**	(2)	**(16)**	(3)	**(28)**	(6)
Segmented revenue, net of royalties	**1,759**	1,894	**5,056**	4,619	**566**	512	**1,262**	1,286	**220**	101	**690**	199
Segmented expenses												
Production	**368**	326	**1,036**	889	**145**	106	**313**	311	**27**	10	**68**	27
Transportation	**88**	75	**259**	215	**3**	5	**11**	16	**-**	-	**-**	-
Depletion, depreciation and amortization	**454**	403	**1,317**	1,183	**90**	82	**212**	236	**43**	18	**132**	38
Asset retirement obligation accretion	**9**	9	**26**	25	**7**	9	**22**	28	**1**	-	**2**	-
Realized risk management activities	**313**	303	**946**	438	**91**	65	**253**	113	**-**	-	**-**	-
Total segmented expenses	**1,232**	1,116	**3,584**	2,750	**336**	267	**811**	704	**71**	28	**202**	65
Segmented earnings (loss) before the following	**527**	778	**1,472**	1,869	**230**	245	**451**	582	**149**	73	**488**	134
Non-segmented expenses												
Administration												
Stock-based compensation (recovery) expense												
Interest, net												
Unrealized risk management activities												
Foreign exchange loss (gain)												
Total non-segmented expenses												
Earnings before taxes												
Taxes other than income tax												
Current income tax expense												
Future income tax expense (recovery)												
Net earnings (loss)												

(millions of Canadian dollars, unaudited)	Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Segmented revenue	**19**	18	**54**	56	**(15)**	(10)	**(42)**	(30)	**2,859**	2,918	**7,948**	7,075
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-	**(310)**	(403)	**(928)**	(945)
Segmented revenue, net of royalties	**19**	18	**54**	56	**(15)**	(10)	**(42)**	(30)	**2,549**	2,515	**7,020**	6,130
Segmented expenses												
Production	**6**	5	**17**	16	**(2)**	(1)	**(4)**	(3)	**544**	446	**1,430**	1,240
Transportation	**-**	-	**-**	-	**(9)**	(9)	**(29)**	(27)	**82**	71	**241**	204
Depletion, depreciation and amortization	**2**	2	**6**	6	**-**	-	**-**	-	**589**	505	**1,667**	1,463
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**17**	18	**50**	53
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**404**	368	**1,199**	551
Total segmented expenses	**8**	7	**23**	22	**(11)**	(10)	**(33)**	(30)	**1,636**	1,408	**4,587**	3,511
Segmented earnings (loss) before the following	**11**	11	**31**	34	**(4)**	-	**(9)**	-	**913**	1,107	**2,433**	2,619
Non-segmented expenses												
Administration									**41**	38	**123**	115
Stock-based compensation (recovery) expense									**(135)**	199	**(37)**	598
Interest, net									**25**	38	**78**	121
Unrealized risk management activities									**(754)**	633	**(772)**	1,750
Foreign exchange loss (gain)									**12**	(119)	**(29)**	(121)
Total non-segmented expenses									**(811)**	789	**(637)**	2,463
Earnings before taxes									**1,724**	318	**3,070**	156
Taxes other than income tax									**77**	61	**215**	143
Current income tax expense									**58**	88	**127**	228
Future income tax expense (recovery)									**473**	18	**517**	(161)
Net earnings (loss)									**1,116**	151	**2,211**	(54)

Net additions to property, plant and equipment

	Nine Months Ended					
	Sep 30, 2006			Sep 30, 2005		
	Cash Expenditures	**Non-Cash/ Fair Value Changes[(1)]**	**Capitalized Costs**	Cash Expenditures	Non-Cash/ Fair Value Changes[(1)]	Capitalized Costs
North America	**$ 2,640**	**$ 14**	**$ 2,654**	$ 1,668	$ (106)	$ 1,562
North Sea	**435**	**(1)**	**434**	268	-	268
Offshore West Africa	**104**	**12**	**116**	321	30	351
Other	**10**	**-**	**10**	5	-	5
Horizon Project[(2)]	**2,252**	**-**	**2,252**	942	-	942
Midstream	**11**	**-**	**11**	3	-	3
Head office	**20**	**-**	**20**	16	-	16
	$ 5,472	**$ 25**	**$ 5,497**	$ 3,223	$ (76)	$ 3,147

(1) Asset retirement obligations, future income tax adjustments on non-tax base assets, and other fair value adjustments.

(2) Cash expenditures also include capitalized interest and stock-based compensation.

	Property, plant and equipment		Total assets	
	Sep 30 2006	Dec 31 2005	**Sep 30 2006**	Dec 31 2005
Segmented assets				
North America	**$ 15,653**	$ 14,310	**$ 16,838**	$ 15,939
North Sea	**1,841**	1,681	**2,078**	1,950
Offshore West Africa	**1,231**	1,253	**1,325**	1,371
Other	**23**	13	**38**	30
Horizon Project	**4,418**	2,169	**4,491**	2,239
Midstream	**208**	203	**357**	258
Head office	**73**	65	**73**	65
	$ 23,447	$ 19,694	**$ 25,200**	$ 21,852

Capitalized interest

Beginning in 2005, following the Board of Directors' approval of the Horizon Project, the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization will cease once construction is substantially complete and the Horizon Project is available for its intended use. For the nine months ended September 30, 2006, pre-tax interest of $130 million was capitalized to the Horizon Project (September 30, 2005 - $45 million).

10. ACQUISITION OF ANADARKO CANADA CORPORATION

In November 2006, the Company expects to complete the acquisition of all of the issued and outstanding common shares of ACC, a subsidiary of Anadarko Petroleum Corporation, for aggregate cash consideration of US$4.075 billion before working capital and other adjustments. ACC's land and production base are all located in Western Canada.

The acquisition will be accounted for based on the purchase method. Results from ACC will be consolidated with the results of the Company effective from the date of acquisition and reported in the North America segment. The purchase price allocation will be based on estimates of the fair values of the assets acquired, the liabilities assumed and the costs to complete the acquisition. The allocation is subject to change as actual amounts are determined.

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated August 2005. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended September 30, 2006:

Interest coverage (times)	
Net earnings[(1)]	17.6x
Cash flow from operations[(2)]	20.6x

(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(2) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

CORPORATE INFORMATION
Officers

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N. Murray Edwards*
Vice-Chairman of the Board

John G. Langille*
Vice-Chairman of the Board

Steve W. Laut*
President & Chief Operating Officer

Douglas A. Proll*
Chief Financial Officer &
Senior Vice-President, Finance

Réal M. Cusson*
Senior Vice-President, Marketing

Réal J.H. Doucet*
Senior Vice-President, Oil Sands

Allen M. Knight*
Senior Vice-President, International & Corporate Development

Tim S. McKay*
Senior Vice-President, Operations

Lyle G. Stevens*
Senior Vice-President, Exploitation

Jeff W. Wilson*
Senior Vice-President, Exploration

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Vice-President, Land

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Vice-President, Investor Relations

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William R. Clapperton
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Larry C. Galea
Vice-President, Operations Planning

Jerry W. Harvey
Vice-President, Commercial Operations

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Vice-President, Engineering Integration

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Vice-President, Field Operations

Richard P. Lock
Vice-President, Bitumen Production

León Miura
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S. John Parr
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Sheldon L. Schroeder
Vice-President, Project Control

Ken W. Stagg
Vice-President, Exploration, West

Steve C. Suche
Vice-President,
Information & Corporate Services

Lynn M. Zeidler
Vice-President,
Horizon Construction Management

Kimberly I. McKay
Treasurer

Bruce E. McGrath
Corporate Secretary

*Management Committee

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ and CNQ.U*

*denotes trading in US funds

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Board of Directors

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Eldon R. Smith, M.D.

David A. Tuer

International Operations

CNR International (U.K.) Limited

Aberdeen, Scotland

Investor Relations

Telephone: (403) 514-7777

Facsimile: (403) 517-7370

Email: ir@cnrl.com

Website: www.cnrl.com

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C A N A D I A N   N A T U R A L   R E S O U R C E S   L I M I T E D
2500, 855 - 2 Street S.W., Calgary, Alberta T2P 4J8
Telephone: (403) 517-6700   Facsimile: (403) 517-7350
Email: ir@cnrl.com
Website: www.cnrl.com

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