Canadian Natural

NEWS RELEASE

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD QUARTERLY AND ANNUAL PRODUCTION VOLUMES AND STRONG FINANCIAL RESULTS

CALGARY, ALBERTA – MARCH 7, 2007 – FOR IMMEDIATE RELEASE

In commenting on fourth quarter 2006 results, Canadian Natural's Chairman, Allan Markin stated, "2006 was a year of both challenges and tremendous opportunities. Higher commodity prices were accompanied by significant cost inflation throughout each of our basins, meaning that we had to be even more vigilant at ensuring full cycle economics were maintained – we responded by optimizing our capital allocation to projects that provided the highest return on capital. For example, we were one of the first in the industry to address the effects of this inflation through significant reductions in natural gas drilling commencing with the second quarter of last year. In late 2006 we were able to complete a major acquisition of natural gas assets at an attractive price, which greatly expanded our project portfolio. In completing this transaction, we further reduced drill bit activity and our exposure to cost inflation for 2007. Integration of people and assets is now complete and we are looking forward to developing our expanded and exceptional portfolio of crude oil and natural gas opportunities. Our management team are firm believers that this re-allocation of capital in 2006 will create significant value in future years."

John Langille, Vice-Chairman, commented "Canadian Natural continues to believe in strong fiscal management. In particular, we have a very strong hedge program underpinning our 2007 cash flows and this, combined with better than expected heavy oil differentials and continued operating and capital discipline, is expected to facilitate our return to the mid range of our targeted debt levels in 2008. Based upon current strip pricing and projected production levels, we would expect to generate 2007 cash flows in excess of $6 billion, above the high end of our original 2007 financial budget."

Canadian Natural's President and Chief Operating Officer, Steve Laut, in commenting on the Company's annual results stated, "Our cultural focus on execution is affording us success notwithstanding cost and operational challenges. On the conventional operations side, we are operating very well in a challenging environment, delivering 2006 proved and probable finding and development costs of $10.09/boe. Our focused teams are determining cost effective alternatives to develop our project portfolio, and deliver on our defined growth plans. On the marketing side, we are aggressively pursuing new markets for our massive heavy oil resource while still managing a large hedge position to ensure cash flow certainty in the short run. Finally, at our Horizon Oil Sands Project ("Horizon Project"), our project management and construction teams continue to deliver. With the Horizon Project 57% complete at the end of 2006 and forecast to achieve approximately 90% completion by the end of 2007, at present we continue to expect final Phase 1 construction costs to not be materially different than our original $6.8 billion target cost with an on-schedule commissioning in the third quarter of 2008. While there are still numerous challenges and inflationary pressures, I believe that our teams have performed very well, again highlighting Canadian Natural's cultural focus on execution."

HIGHLIGHTS

($ millions, except as noted)	Quarterly Results Q4/06	Q3/06	Q4/05	Year End Results 2006	2005
Net earnings	**$ 313**	$ 1,116	$ 1,104	**$ 2,524**	$ 1,050
per common share, basic	**$ 0.58**	$ 2.08	$ 2.06	**$ 4.70**	$ 1.96
Adjusted net earnings from operations (1)	**$ 412**	$ 470	$ 601	**$ 1,664**	$ 2,034
per common share, basic	**$ 0.77**	$ 0.87	$ 1.12	**$ 3.10**	$ 3.79
Cash flow from operations (2)	**$ 1,293**	$ 1,313	$ 1,490	**$ 4,932**	$ 5,021
per common share, basic	**$ 2.41**	$ 2.44	$ 2.78	**$ 9.18**	$ 9.36
Capital expenditures, net of dispositions	**$ 6,497**	$ 1,661	$ 1,679	**$ 12,025**	$ 4,932
Debt to book capitalization	**51%**	35%	29%	**51%**	29%
Daily production, before royalties					
Natural gas (mmcf/d)	**1,620**	1,437	1,423	**1,492**	1,439
Crude oil and NGLs (bbl/d)	**343,705**	321,665	340,268	**331,998**	313,168
Equivalent production (boe/d)	**613,764**	561,152	577,505	**580,724**	552,960

(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.

- Record North America natural gas production in Q4/06 represented an increase of 13% from Q3/06 and a 14% increase over Q4/05 due to the acquisition of Anadarko Canada Corporation ("ACC"), a subsidiary of Anadarko Petroleum Corporation volumes in November, which was partially offset by normal production declines and the effects of a reduced drilling emphasis due to a re-allocation of capital away from higher cost organic natural gas development.

- Record crude oil production volumes in Q4/06 represented a 7% increase from Q3/06 and 1% from Q4/05. The increase from Q3/06 was largely the result of higher North Sea and thermal crude oil volumes as well as the ACC acquisition. The increase from Q4/05 was driven by higher Canadian crude oil production partially offset by lower international volumes.

- Quarterly cash flow of $1.3 billion, essentially flat with Q3/06 and a 13% decrease from Q4/05. The decrease from Q4/05 reflected lower natural gas pricing, higher production expenses 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, higher crude oil and NGLs and natural gas sales volumes and lower realized risk management losses.

- Quarterly net earnings of $313 million, representing a 72% decrease from both Q3/06 and Q4/05. Net earnings in Q4/06 included unrealized after-tax expenses of $99 million related to the effects of risk management activities, foreign exchange losses and stock-based compensation expense, compared to net after-tax income of $503 million in Q4/05 and $646 million of after-tax income in Q3/06.

- Quarterly adjusted net earnings from operations of $412 million, 12% lower than Q3/06 results and a 31% decrease from Q4/05 reflecting lower cash flow and higher DD&A rates.

- Completed the acquisition and integration of ACC. ACC, which was acquired for aggregate cash consideration of $4,641 million including working capital and other adjustments and was included in Canadian Natural's results effective November 2006. Substantially all of 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.

- Independent qualified reserve evaluators evaluated 100% of the Company's conventional crude oil and natural gas reserves under constant prices and costs as at December 31, 2006:

- Total net proved reserves from conventional operations at the end of 2006 amounted to 1.3 billion barrels of crude oil and NGLs and 3.8 trillion cubic feet of natural gas. Total net proved conventional reserves increased by 22%, with net proved crude oil reserves increasing by 18% and net proved natural gas reserves increasing by 34%.
- Net proved reserve additions from conventional operations equaled 295% of 2006 net production, at a finding and onstream cost of $16.16 per barrel of oil equivalent. The Company's three-year average proved finding and onstream costs was $14.28 per barrel of oil equivalent.
- Total net proved and probable reserves from conventional operations at the end of 2006 amounted to 2.1 billion barrels of crude oil and NGLs and 5.0 trillion cubic feet of natural gas. Total proved and probable net conventional reserves increased by 30%, with net proved and probable crude oil reserves increasing by 28% and net proved and probable natural gas reserves increasing by 35%.
- Net proved and probable reserve additions from conventional operations equaled 472% of 2006 net production, at a finding and onstream cost of $10.09 per barrel of oil equivalent. The Company's three-year average net proved and probable finding and onstream costs was $9.88 per barrel of oil equivalent.
- Using net proved and probable finding and onstream costs, the Company achieved an overall recycle ratio of 3.3x (2.0x using only proved reserve additions) during 2006.

▪ Independent qualified reserve evaluators evaluated 100% of the Company's Phase 1 to Phase 3 oil sands mining reserves for the Horizon Project under constant prices as at December 31, 2006, which resulted in 2.3 billion barrels of gross lease proved bitumen reserves and 3.5 billion barrels of gross lease proved and probable bitumen reserves. This represents an increase from the December 31, 2005 evaluation which had 2.2 billion barrels of gross lease proved bitumen reserves and 3.4 billion barrels of gross lease proved and probable bitumen reserves.

▪ Completed a Q4/06 drilling program of 265 net wells, excluding stratigraphic test and service wells, with an 89% success ratio, reflecting Canadian Natural's strong, predictable, low-risk asset base.

▪ Increased an already strong undeveloped conventional land base in Canada to 12.6 million net acres - a key asset in today's highly competitive industry – including an additional 1.5 million net undeveloped acres acquired through the ACC acquisition.

▪ The Horizon Project remains slightly ahead of schedule as at December 31, 2006. The Horizon Project exited 2006 57% complete with approximately $5.1 billion in purchase orders and contracts having been awarded to date. Cost pressures are causing cost estimates for certain isolated pieces of the project to be above target cost. However, at present such cost increases are not expected to, in aggregate, result in Phase 1 construction 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 the expansion of the enhanced crude oil recovery program. Pelican Lake crude oil production averaged approximately 29,200 bbl/d during the quarter, up 5% or approximately 1,600 bbl/d from Q4/05. Production is expected to continue to increase in Q1/07 and throughout the rest of 2007.

▪ The Company's 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 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. 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 65% of expected crude oil volumes and approximately 75% of expected natural gas volumes have been hedged for 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for 2007 at a strike price of US$60.00 per barrel. The Company is extending its hedge program into 2008 whereby 150,000 bbl/d of crude oil volumes have been hedged (100,000 bbl/d of price collars with a US$60.00 floor and 50,000 bbl/d of put options with a US$55.00 strike price). In addition, 900,000 GJ/d of natural gas volumes have been hedged through the use of price collars for the first quarter of 2008 (400,000 GJ/d with a floor of $7.00 and 500,000 GJ/d with a floor of $7.50).

▪ Seventh straight year of dividend increases. The 2007 quarterly dividend will increase 13% from $0.075 per common share to $0.085 per common share, effective with the April 2007 payment.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in 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 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 Dec 31, 2006 (thousands of net acres)	**Drilling activity year ended Dec 31, 2006 (net wells)**
Canadian conventional		
Northeast British Columbia	**2,721**	**196**
Northwest Alberta	**1,750**	**194**
Northern Plains	**6,765**	**728**
Southern Plains	**870**	**120**
Southeast Saskatchewan	**117**	**75**
In-situ Oil Sands	**407**	**247**
	12,630	**1,560**
Horizon Oil Sands Project	**116**	**163**
United Kingdom North Sea	**299**	**9**
Offshore West Africa	**207**	**6**
	13,252	**1,738**

Drilling activity (number of wells)

	Year Ended Dec 31			
	2006		2005	
	Gross	**Net**	Gross	Net
Crude oil	**666**	**603**	685	627
Natural gas	**855**	**641**	1,071	890
Dry	**133**	**119**	136	117
Subtotal	**1,654**	**1,363**	1,892	1,634
Stratigraphic test / service wells	**376**	**375**	251	248
Total	**2,030**	**1,738**	2,143	1,882
Success rate (excluding stratigraphic test / service wells)		**91%**		93%

North America natural gas	Quarterly Results			Year End Results	
	Q4/06	Q3/06	Q4/05	**2006**	2005
Natural gas production (mmcf/d)	**1,594**	1,416	1,402	**1,468**	1,416
Net wells targeting natural gas	**74**	111	295	**732**	975
Net successful wells drilled	**60**	98	279	**641**	890
Success rate	**81%**	88%	95%	**88%**	91%

- The 13% increase in production reflected the inclusion of ACC production effective November 2006 partially offset by normal production declines and the effects of the Company's strategic decision to reduce organic growth spending due to high industry costs. As a result of the strategic move to reduce natural gas drilling, the Company experienced a 75% decrease in Q4/06 drilling compared to Q4/05.

- ACC was fully integrated into Canadian Natural within weeks of closing with the assets performing at or above expectation.

- High drilling success rates reflect Canadian Natural's low-risk exploitation approach and high quality land base. The Q4/06 drilling program represented an active program across the Company's core regions. In Northeast British Columbia 9 net wells targeting natural gas were drilled, while in Northwest Alberta 23 net wells were drilled, including 6 Cardium targets. In Northern and Southern Plains, a total of 2 net deep, 11 net coal bed methane, 9 net shallow and 20 net conventional natural gas wells were targeted.

- Planned drilling activity for Q1/07 includes 241 wells targeting natural gas compared to a total of 499 wells drilled in Q1/06, again reflecting the Company's decision to proactively reduce exposure to over-inflated service and supply costs.

North America crude oil and NGLs	Quarterly Results			Year End Results	
	Q4/06	Q3/06	Q4/05	**2006**	2005
Crude oil and NGLs production (bbl/d)	**249,565**	233,440	230,263	**235,253**	221,669
Net wells targeting crude oil	**188**	263	191	**619**	642
Net successful wells drilled	**174**	253	185	**591**	612
Success rate	**93%**	96%	97%	**95%**	95%

- In contrast to natural gas, the crude oil program utilizes fewer third party services and experienced lower cost inflation while receiving higher wellhead pricing. In 2006, the Company contracted two 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 2006 will not be fully realized until mid 2007.

- Q4/06 North America crude oil and NGLs production increased 7% over Q3/06 and 8% over Q4/05. This performance reflected continued success at the Primrose thermal crude oil project where new pads have transitioned from the steaming cycle to the production cycle, as well as continued production improvements at Pelican Lake. Many of the newer Primrose pads have recently commenced a steaming phase in Q1/07, which will result in decreased production during the first quarter of 2007.

- During Q4/06, drilling activity included 110 net wells targeting heavy crude oil, 39 net wells targeting Pelican Lake crude oil, 18 net wells targeting thermal crude oil and 21 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 the Company's results in the first half of 2007.

- The Primrose East expansion program continues with a planned 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 plan identified to unlock the value from Canadian Natural's thermal crude oil resource base. Detailed engineering, procurement and site clearing are underway.

- At Pelican Lake, the development of land acreage and secondary recovery implementation projects continued as planned, with 39 horizontal producing wells drilled and 10 production wells converted to injection wells (four for water and six for polymer injection) in Q4/06. Results from the polymer flood continue to be positive and 4 additional polymer skids were installed in Q4/06. The program continues to be optimized and the results will be monitored. Production remained relatively flat with Q3/06 levels largely reflecting reduced production associated with converting producer wells into injector wells.

- Planned drilling activity for Q1/07 includes 199 net crude oil wells.

- In early 2007, Canadian Natural issued its proposed development plan for the 30,000 bbl/d Kirby In-Situ Oil Sands Project located approximately 85 km northeast of Lac La Biche in the Regional Municipality of Wood Buffalo. The Company is targeting to file its formal regulatory application documents for this project in the latter half of 2007.

Canadian Natural Upgrader Project

Originally announced in the fall of 2005, the Scoping Study for the Canadian Natural Upgrader continued during Q4/06 and into early 2007. The terms of reference for this study involved the evaluation of product alternatives, location, technology, gasification and integration with existing assets using the same disciplined approach utilized in the Horizon Project. The next steps in this process would include a Design Basis Memorandum ("DBM") and Engineering Design Specification ("EDS") which would be required to be completed prior to construction and sanctioning of the project by the Board of Directors.

Based upon the results of the Scoping Study, which identified growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

International

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

	Quarterly Results			Year End Results	
	Q4/06	Q3/06	Q4/05	**2006**	2005
Crude oil production (bbl/d)					
North Sea	**61,786**	53,988	66,798	**60,056**	68,593
Offshore West Africa	**32,354**	34,237	43,207	**36,689**	22,906
Natural gas production (mmcf/d)					
North Sea	**16**	11	15	**15**	19
Offshore West Africa	**10**	10	6	**9**	4
Net wells targeting crude oil	**2.3**	2.2	5.9	**11.5**	17.3
Net successful wells drilled	**2.3**	2.2	5.0	**11.5**	15.0
Success rate	**100%**	100%	85%	**100%**	87%

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. Examples of this type of work are the ongoing development at the Columba Terraces and the Lyell Field.

- During Q4/06, 2.5 net wells were drilled with an additional 2 net wells drilling at quarter end. Production levels during the quarter were in line with expectations, following successful completion of planned maintenance in the third quarter and continued strong performance at Banff Field following completion of gas compression upgrade work.

- The Columba E Raw Water Injection project continued during Q4/06. Drilling commenced on the first of the 2 planned water injection wells, with both wells expected to be completed during the second quarter of 2007.

- Plans for the further development of the Lyell Field progressed. The timeline of the project entails drilling 4 net wells and the workover of 2 existing net wells. During Q4/06, the Company completed the construction, installation and tie-in of subsea infrastructure, and commenced drilling the first of the planned wells.

Offshore West Africa

- During Q4/06, 1.8 net wells were drilled with 1 additional net well drilling at quarter end.

- At the Espoir Field, crude oil production exceeded expectations during Q4/06, averaging approximately 19,000 bbl/d net to Canadian Natural during the quarter. A third production well at West Espoir was brought onstream in Q4/06, as were two water injection wells. Development drilling will continue until 2008, with wells being brought onstream as they are completed. Production at Espoir will be impacted by a planned maintenance shutdown during Q1/07.

- Net production at Baobab averaged approximately 13,000 bbl/d during the quarter, reflecting the shut in of production from five of the ten production wells, due to ongoing challenges with sand and solids production. This has resulted in approximately 15,500 bbl/d of reduced production capacity at the field. Canadian Natural is currently investigating the rig market to identify suitable availability to proceed to the second phase of the field development, including potentially recompleting the wells that are currently experiencing production limitations. Current production remains stable with no sand production issues.

- In Gabon, the Olowi project received Board sanction for development in November 2006. Development plans include a floating production, storage and offtake vessel ("FPSO"), handling production from four shallow water wellhead towers. During Q4/06, the Company signed a lease agreement for the FPSO with a primary term of ten years, with arrival of the vessel scheduled for 2008. A further contract was awarded for the wellhead towers, with additional contracts expected to be awarded during Q1/07. First oil is currently targeted for late-2008, with 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 targeted to commence in the third quarter of 2008.

- 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 Q4/06, the Company awarded a further C$300 million of contracts, including several that were previously deferred in order to optimize pricing. This brings the total awarded contracts to C$5.1 billion. To date, 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. At this point in time for the work done to date (engineering, procurement and construction) - which translates to a 57% overall project completion level - the Company is at the target cost forecast. Field construction itself is 42% complete and work on 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 43% 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, at present such cost increases are not expected to, in aggregate, result in total construction costs of the project being materially different than the original target construction cost of $6.8 billion. Further, Canadian Natural remains on track for commissioning during the third quarter of 2008.

- 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). Several options are being developed to ensure shareholder value-creation and to manage the risks associated with expansion in a high cost inflationary environment.

- The quarterly update for Phase 1 of the Horizon Project is as follows:

Project status summary	**Q4/06**		Q1/07
	Actual	Plan	Plan
Phase 1 - Work progress (cumulative)	**57%**	55%	65%
Phase 1 - Construction capital spending (cumulative)*	**59%**	58%	68%

** Relates to overall Phase 1 construction capital of $6.8 billion.*

Accomplished During the Fourth Quarter of 2006

Detailed Engineering

- Overall detailed engineering 94% complete and is substantially completed in most areas.

Procurement

- Overall progress 84% complete. Most major equipment is purchased and on site.

- Awarded over $5.1 billion in purchase orders and contracts to date.

- Awarded General Mechanical Contracts for Hydrotreater and Cogeneration areas.

Modularization

- Delivered an additional 327 oversized loads to site for a total of 973 loads, representing approximately 59% of the Phase 1 total to be shipped.

Construction

- Overall progress 42% complete.

- Set 333 main piperack modules.

- Exceeded the 2006 High Voltage (35kV) cable pull plan by 15% (30,500 meters), ensuring that all critical pulls have been completed.

- 5 of 6 Modular Substations have been installed and re-instated at site, with High Voltage cable terminations ongoing.

- Mine overburden removal has moved 25 million bank cubic meters, which is approximately 35% complete and 4% ahead of target.

- Ore Preparation Area completed construction of the Mechanically Stabilized Earth Shear Wall and transported the 800 tonne module assemblies onto their foundations.

- Bitumen Production Administration Building was completed and occupied.

- Camp 3 was completed and ready for occupancy.

- Commenced Flotation Cell and Pump Box installation in Extraction.

- Began work on R1 and R2 pump house for piping corridors.

- Commenced installation of large bore piping in Coker/DRU.

Milestones for the First Quarter of 2007

- Complete Primary Separation Cell Piping in Extraction.

- Ready High Pressure natural gas piping for Commissioning.

- Initiate module setting in Hydrotreater area.

- Complete Cooling Tower erection.

- Complete installation of the last remaining 35kV substation.

Operations Readiness

- Canadian Natural has had operations staff involved in the design, procurement and construction of the Horizon Project from project commencement. Canadian Natural believes this has resulted in a design that will be less difficult to commission and start-up had there been no operations staff involved. The operations staff is responsible for the commissioning and start-up of the facilities and have already prepared a commissioning and start-up schedule which is directly linked to the construction schedule. This allows the project team to identify challenges early on and ensure that adequate contingency plans are in place.

- Currently there are 134 operations staff employed in the development of start-up procedures, preparation of training programs, recruitment of additional staff, establishment of maintenance programs and operating several plant systems.

- The operations team has had the opportunity to test-run many programs through the early operation of plant systems. The team is currently operating some mine equipment and several plant facilities such as water treatment, sewage treatment, communications, natural gas and power distribution. As a result, the team has already developed several early learnings that have been incorporated into later start-up plans.

- Throughout 2007, increasing focus will be placed upon commissioning and start-up as operations staff levels increase and procedures are optimized.

MARKETING

	Quarterly Results			Year End Results	
	Q4/06	Q3/06	Q4/05	**2006**	2005
Crude oil and NGLs pricing					
WTI [1] benchmark price (US$/bbl)	**$ 60.21**	$ 70.55	$ 60.04	**$ 66.25**	$ 56.61
Lloyd Blend Heavy oil differential from WTI (%)	**35%**	27%	40%	**33%**	37%
Corporate average pricing before risk management (C$/bbl)	**$ 47.27**	$ 62.55	$ 46.38	**$ 53.65**	$ 46.86
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 6.03**	$ 5.72	$ 11.07	**$ 6.62**	$ 8.05
Corporate average pricing before risk management (C$/mcf)	**$ 6.66**	$ 5.83	$ 11.67	**$ 6.72**	$ 8.57

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

- Heavy crude oil differentials, as expected, widened in Q4/06 from Q3/06 averaging 35% of WTI, reflecting normal seasonality. The differential remained favorable in comparison to Q4/05, due to the addition of heavy oil pipeline capacity to the US Gulf Coast in spring 2006. The Company has committed to 25,000 bbl/d of pipeline capacity on 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. In early Q1/07, the Company has experienced a narrowing of the differential to under 30%, below seasonally expected differentials.

- During Q4/06, the Company contributed approximately 135,000 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.

FINANCIAL REVIEW

- Canadian Natural has structured its financial position 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 613,000 boe/d in Q4/06, comprised of approximately 44% natural gas and 56% crude oil - with 95% of production located in G7 countries with stable and secure economies.

  – Financial stability and liquidity – approximately $7.8 billion of bank credit facilities, with an aggregate $1,115 million of unused bank lines available at December 31, 2006.

- The Company's 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 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. 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 65% of expected crude oil volumes and approximately 75% of expected natural gas volumes have been hedged for 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for 2007 at a strike price of US$60.00 per barrel. The Company is extending its hedge program into 2008 whereby 150,000 bbl/d of crude oil volumes have been hedged (100,000 bbl/d of price collars with a US$60.00 floor and 50,000 bbl/d of put options with a US$55.00 strike price). In addition, 900,000 GJ/d of natural gas volumes have been hedged through the use of price collars for the first quarter of 2008 (400,000 GJ/d with a floor of $7.00 and 500,000 GJ/d with a floor of $7.50).

- 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 asset reflected, at December 31, 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 December 31, 2006. Due to changes in the crude oil and natural gas forward pricing, and the reversal of prior year unrealized losses, the Company recorded a net unrealized gain of $1,013 million ($674 million after-tax) on its risk management activities for the year ended December 31, 2006 (December 31, 2005 - unrealized loss of $925 million, $607 million after-tax), including an unrealized gain of $241 million ($166 million after-tax) for the three months ended December 31, 2006 (December 31, 2005 - unrealized gain of $825 million, $583 million after-tax; September 30, 2006 - unrealized gain of $754 million, $496 million after-tax).

- During 2006 under the terms of the Normal Course Issuer Bid that 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, 485,000 common shares were repurchased for cancellation at an average price of $57.33/share. No shares were repurchased under this facility during Q4/06. In Q1/07 this facility was renewed, allowing for the repurchase of up to 26.9 million shares, again through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.

- Seventh straight year of dividend increases. The 2007 quarterly dividends will increase 13% from $0.075 per common share to $0.085 per common share, effective with the April 2007 payment.

OUTLOOK

The Company forecasts 2007 production levels before royalties to average between 1,594 and 1,664 mmcf/d of natural gas and between 315 and 360 mbbl/d of crude oil and NGLs. Q1/07 production guidance before royalties is forecast to average between 1,696 and 1,717 mmcf/d of natural gas and between 315 and 331 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/.

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/.

YEAR-END RESERVES

Determination of reserves

- For the year ended December 31, 2006, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule"), and Ryder Scott Company ("Ryder Scott"), to evaluate 100% of the Company's conventional proved and proved and probable oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Sproule evaluated the Company's North American assets and Ryder Scott evaluated its international assets. Canadian Natural has been granted an exemption from National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards. The first is an additional requirement to disclose both proved, and proved and probable reserves, as well as related future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and cost between the two standards is not material.

- The Company has disclosed proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information.

- The SEC requires that oil sands mining reserves be disclosed separately from conventional oil and gas disclosure. Canadian Natural retained a qualified independent reserve evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate Phase 1 to Phase 3 of the Company's Horizon Project. Adhering to SEC Industry Guide 7 requirements, the gross lease proved bitumen reserves as of December 31, 2006 under constant prices were 2.3 billion barrels. The gross lease proved and probable bitumen reserves were 3.5 billion barrels.

- The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ as to the Company's reserves.

North America Conventional Net Reserves

- Natural gas proved reserves increased by 35%, replacing 323% of 2006 production. Similarly, crude oil and NGLs proved reserves increased by 28%, replacing 357% of production. This was accomplished at all-in finding and on-stream cost of $15.86 per barrel of oil equivalent for proved reserves and $9.53 per barrel of oil equivalent for proved and probable reserves.

International Conventional Net Reserves

- North Sea proved reserves grew by 10 million barrels of oil equivalent to 305 million barrels of oil equivalent or about 16% of total proved Company reserves. Reserve additions were primarily achieved through optimization of waterflood design, an infill drilling program and recompletions.

- In Offshore West Africa, where the Government share of production is contractually determined as a percentage of production volume and apportioned between income tax and royalties for reserves and accounting purposes, proved reserves decreased to 139 million barrels of oil equivalent as a 2006 corporate income tax rate reduction effectively increased the royalty allocations. Generally, the Company receives a greater portion of production until capital development costs are recouped whereupon government allocation of production substantially increases. With the current high world crude oil price, these projects generally require fewer of the reserves to cover payout of capital costs, thereby reducing the reserves ultimately allocated to the Company over the field life.

Conventional Proved Undeveloped Net Reserves ("PUDs")

- In the Evaluation Reports, 47% of crude oil proved reserves were assigned to the proved undeveloped category. This is a 9 percentage point increase from the 38% recorded in 2005. Of the 2006 crude oil PUD reserves, 57% are associated with our thermal oil sands projects where extensive pool delineation and geological analysis justifies continued development and expansion.
- In the Evaluation Reports, 22% of natural gas proved reserves were assigned to the proved undeveloped category reflecting the generally shorter lead times required for natural gas developments in Canada.

Conventional Proved and Probable Net Reserves

- In the Evaluation Reports, total proved and probable reserves increased by 30%, driven largely by the 42% increase in North America.

RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES[1]

	December 31, 2006			
	Proved Developed[2]	**Proved Undeveloped[2]**	**Proved Total[2]**	**Proved and Probable[3]**
Crude oil and NGLs (mmbbl)				
North America	**420**	**467**	**887**	**1,502**
North Sea	**214**	**85**	**299**	**422**
Offshore West Africa	**63**	**67**	**130**	**195**
	697	**619**	**1,316**	**2,119**
Natural gas (bcf)				
North America	**2,934**	**771**	**3,705**	**4,857**
North Sea	**17**	**20**	**37**	**93**
Offshore West Africa	**12**	**44**	**56**	**99**
	2,963	**835**	**3,798**	**5,049**
Total reserves (mmboe)	**1,191**	**758**	**1,949**	**2,961**
Reserve replacement ratio[4] (%)			**295%**	**472%**
Cost to develop[5] ($/boe)				
10% discount	**1.33**	**6.46**	**3.32**	**3.08**
15% discount	**1.12**	**5.80**	**2.94**	**2.66**
Present value of conventional reserves[6] ($ millions)				
10% discount	**20,028**	**7,469**	**27,497**	**37,291**
15% discount	**17,296**	**5,247**	**22,543**	**29,350**

RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES[1]

	December 31, 2005			
	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude oil and NGLs (mmbbl)				
North America	402	292	694	1,035
North Sea	214	76	290	417
Offshore West Africa	80	54	134	206
	696	422	1,118	1,658
Natural gas (bcf)				
North America	2,300	441	2,741	3,548
North Sea	16	13	29	69
Offshore West Africa	10	62	72	110
	2,326	516	2,842	3,727
Total reserves (mmboe)	1,083	509	1,592	2,279
Reserve replacement ratio[4] (%)			145%	195%
Cost to develop[5] ($/boe)				
10% discount	0.79	5.69	2.36	2.55
15% discount	0.67	5.15	2.11	2.25
Present value of conventional reserves[6] ($ millions)				
10% discount	24,275	6,342	30,617	38,682
15% discount	20,939	4,881	25,820	31,642

OIL SANDS MINING RESERVES[1][7]

The following table sets out Canadian Natural's reserves of bitumen and synthetic crude oil from the Horizon Project Oil Sands leases.

	As of Dec 31, 2006		As of Dec 31, 2005	
	Proved Total	Proved and Probable	Proved Total	Proved and Probable
Gross reserves*, before royalties (mmbbl)				
Bitumen	**2,275**	**3,530**	2,235	3,430
Synthetic crude oil	**1,866**	**2,962**	1,833	2,878

* *Represents gross lease reserves.*
SCO reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and SCO are not additive.

CONVENTIONAL CRUDE OIL AND NGLs RESERVES RECONCILIATION, NET OF ROYALTIES[(1)]

	North America	North Sea	Offshore West Africa	Total
Proved reserves (mmbbl)				
Reserves, December 31, 2004	**648**	**303**	**115**	**1,066**
Extensions and discoveries	98	-	-	98
Infill drilling	3	3	2	8
Improved recovery	-	-	-	-
Property purchases	-	-	15	15
Property disposals	(3)	-	-	(3)
Production	(70)	(25)	(8)	(103)
Revisions of prior estimates	18	9	10	37
Reserves, December 31, 2005	**694**	**290**	**134**	**1,118**
Extensions and discoveries	**53**	**3**	**-**	**56**
Infill drilling	**190**	**14**	**-**	**204**
Improved recovery	**-**	**12**	**-**	**12**
Property purchases	**26**	**-**	**-**	**26**
Property disposals	**-**	**-**	**-**	**-**
Production	**(75)**	**(22)**	**(13)**	**(110)**
Revisions of prior estimates	**(1)**	**2**	**9**	**10**
Reserves, December 31, 2006	**887**	**299**	**130**	**1,316**

	North America	North Sea	Offshore West Africa	Total
Proved and probable reserves (mmbbl)				
Reserves, December 31, 2004	**926**	**415**	**196**	**1,537**
Extensions and discoveries	200	-	-	200
Infill drilling	3	5	6	14
Improved recovery	-	-	-	-
Property purchases	-	-	17	17
Property disposals	(4)	-	-	(4)
Production	(70)	(25)	(8)	(103)
Revisions of prior estimates	(20)	22	(5)	(3)
Reserves, December 31, 2005	**1,035**	**417**	**206**	**1,658**
Extensions and discoveries	**128**	**3**	**-**	**131**
Infill drilling	**384**	**17**	**-**	**401**
Improved recovery	**-**	**12**	**-**	**12**
Property purchases	**34**	**-**	**-**	**34**
Property disposals	**-**	**-**	**-**	**-**
Production	**(75)**	**(22)**	**(13)**	**(110)**
Revisions of prior estimates	**(4)**	**(5)**	**2**	**(7)**
Reserves, December 31, 2006	**1,502**	**422**	**195**	**2,119**

CONVENTIONAL NATURAL GAS RESERVES RECONCILIATION, NET OF ROYALTIES[1]

	North America	North Sea	Offshore West Africa	Total
Proved reserves (bcf)				
Reserves, December 31, 2004	**2,591**	**27**	**72**	**2,690**
Extensions and discoveries	506	-	-	506
Infill drilling	22	-	-	22
Improved recovery	8	-	-	8
Property purchases	6	-	-	6
Property disposals	(23)	-	-	(23)
Production	(411)	(7)	(1)	(419)
Revisions of prior estimates	42	9	1	52
Reserves, December 31, 2005	**2,741**	**29**	**72**	**2,842**
Extensions and discoveries	**250**	**-**	**-**	**250**
Infill drilling	**71**	**-**	**-**	**71**
Improved recovery	**3**	**-**	**-**	**3**
Property purchases	**1,111**	**-**	**-**	**1,111**
Property disposals	**(1)**	**-**	**-**	**(1)**
Production	**(433)**	**(5)**	**(3)**	**(441)**
Revisions of prior estimates	**(37)**	**13**	**(13)**	**(37)**
Reserves, December 31, 2006	**3,705**	**37**	**56**	**3,798**
Proved and probable reserves (bcf)				
Reserves, December 31, 2004	**3,319**	**57**	**90**	**3,466**
Extensions and discoveries	645	-	-	645
Infill drilling	23	-	1	24
Improved recovery	14	-	-	14
Property purchases	8	-	-	8
Property disposals	(30)	-	-	(30)
Production	(411)	(7)	(1)	(419)
Revisions of prior estimates	(20)	19	20	19
Reserves, December 31, 2005	**3,548**	**69**	**110**	**3,727**
Extensions and discoveries	**307**	**-**	**-**	**307**
Infill drilling	**95**	**-**	**-**	**95**
Improved recovery	**4**	**-**	**-**	**4**
Property purchases	**1,466**	**-**	**-**	**1,466**
Property disposals	**(1)**	**-**	**-**	**(1)**
Production	**(433)**	**(5)**	**(3)**	**(441)**
Revisions of prior estimates	**(129)**	**29**	**(8)**	**(108)**
Reserves, December 31, 2006	**4,857**	**93**	**99**	**5,049**

The following information for reserves before royalties is provided for comparative purposes:

CONVENTIONAL RESERVES, BEFORE ROYALTIES[1]

	December 31, 2006			
	Proved Developed[2]	**Proved Undeveloped**[2]	**Proved Total**[2]	**Proved and Probable**[3]
Crude oil and NGLs (mmbbl)				
North America	**495**	**548**	**1,043**	**1,753**
North Sea	**214**	**85**	**299**	**421**
Offshore West Africa	**70**	**75**	**145**	**223**
	779	**708**	**1,487**	**2,397**
Natural gas (bcf)				
North America	**3,587**	**920**	**4,507**	**5,898**
North Sea	**17**	**20**	**37**	**93**
Offshore West Africa	**15**	**54**	**69**	**121**
	3,619	**994**	**4,613**	**6,112**
Total reserves (mmboe)	**1,382**	**874**	**2,256**	**3,416**

	December 31, 2005			
	Proved Developed[2]	**Proved Undeveloped**[2]	**Proved Total**[2]	**Proved and Probable**[3]
Crude oil and NGLs (mmbbl)				
North America	462	323	785	1,154
North Sea	214	76	290	417
Offshore West Africa	86	62	148	230
	762	461	1,223	1,801
Natural gas (bcf)				
North America	2,844	534	3,378	4,372
North Sea	16	13	29	69
Offshore West Africa	11	72	83	127
	2,871	619	3,490	4,568
Total reserves (mmboe)	1,240	564	1,804	2,562

CONVENTIONAL FINDING AND ONSTREAM COSTS

	2006	2005	2004	Three Year Total
Net reserve replacement expenditures ($ millions)	**8,727**	3,361	4,259	**16,347**
Net reserve additions (mmboe) (8)				
Proved	**540**	251	354	**1,145**
Proved and probable	**865**	337	453	**1,655**
Finding and on stream costs ($/boe) (9)				
Proved	**16.16**	13.41	12.03	**14.28**
Proved and probable	**10.09**	9.97	9.40	**9.88**

(1) Reserve estimates and present value calculations are based upon year end constant reference price assumptions as detailed below as well as constant year-end costs.

Crude oil and NGLs	*Company Average Price (C$/bbl)*	*WTI @ Cushing Oklahoma (US$/bbl)*	*Hardisty Heavy 12º API (C$/bbl)*	*North Sea Brent (US$/bbl)*
2006	*51.11*	*61.05*	*41.94*	*58.93*
2005	*46.12*	*61.04*	*32.64*	*58.21*
2004	*32.14*	*44.04*	*17.45*	*40.47*

Natural gas	*Company Average Price (C$/mcf)*	*Henry Hub Louisiana (US$/mmbtu)*	*Alberta AECO C (C$/mmbtu)*	*British Columbia Huntingdon Sumas (C$/mmbtu)*
2006	*6.07*	*5.52*	*6.13*	*6.52*
2005	*9.45*	*10.08*	*9.99*	*9.53*
2004	*6.44*	*6.62*	*6.78*	*6.94*

A foreign exchange rate of US$0.86/C$1.00 was used in the 2006 evaluation; US$0.86/C$1.00 was used in the 2005 evaluation; US$0.83/C$1.00 was used in the 2004 evaluation.

(2) Proved reserve estimates and values were evaluated in accordance with the Securities and Exchange Commission ("SEC") requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

(3) Proved and probable reserve estimates and values were evaluated in accordance with the standards of the Canadian Oil and Gas Evaluation Handbook ("COGEH") and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

(4) Reserve replacement ratios were calculated using annual net reserve additions comprised of all change categories divided by the net production for that year.

(5) Cost to develop represents total discounted future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

(6) Present value of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, before income taxes. Future development costs and associated material well abandonment costs have been applied against future net revenues.

(7) Synthetic crude oil reserves are based on upgrading of the bitumen reserves using technologies implemented at the Horizon Project. The reserve values shown for bitumen and synthetic crude oil are not additive.

(8) Reserves additions are comprised of all categories of reserves changes, exclusive of production.

(9) Reserves finding and on stream costs are determined by dividing total capital cash expenditures for each year by net reserves additions for that year. It excludes costs associated with head office, abandonments, midstream and the Horizon Project.

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 the Company, should be read in conjunction with the unaudited interim consolidated financial statements for the year and three months ended December 31, 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 and cash flow from operations. 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 figures related to the presentation of gross revenues and gross transportation and blending provided for prior periods have been reclassified to conform to the presentation adopted in 2006.

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 also presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the year and three months ended December 31, 2006 in relation to the comparable periods in 2005 and the third quarter of 2006. The accompanying tables form an integral part of this MD&A. This MD&A is dated March 3, 2007. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2005, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS
(millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Revenue, before royalties [1]	**$ 2,826**	$ 3,108	$ 3,319	**$ 11,643**	$ 11,130
Net earnings	**$ 313**	$ 1,116	$ 1,104	**$ 2,524**	$ 1,050
Per common share – basic	**$ 0.58**	$ 2.08	$ 2.06	**$ 4.70**	$ 1.96
– diluted	**$ 0.58**	$ 2.08	$ 2.06	**$ 4.70**	$ 1.95
Adjusted net earnings from operations [2]	**$ 412**	$ 470	$ 601	**$ 1,664**	$ 2,034
Per common share – basic	**$ 0.77**	$ 0.87	$ 1.12	**$ 3.10**	$ 3.79
– diluted	**$ 0.77**	$ 0.87	$ 1.12	**$ 3.10**	$ 3.78
Cash flow from operations [3]	**$ 1,293**	$ 1,313	$ 1,490	**$ 4,932**	$ 5,021
Per common share – basic	**$ 2.41**	$ 2.44	$ 2.78	**$ 9.18**	$ 9.36
– diluted	**$ 2.41**	$ 2.44	$ 2.78	**$ 9.18**	$ 9.33
Capital expenditures, net of dispositions	**$ 6,497**	$ 1,661	$ 1,679	**$ 12,025**	$ 4,932

(1) Blending costs previously netted against gross revenues in prior periods have been reclassified to transportation expense to conform to the presentation adopted in 2006.

(2) 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			*Year Ended*	
($ millions)	***Dec 31 2006***	*Sep 30 2006*	*Dec 31 2005*	***Dec 31 2006***	*Dec 31 2005*
Net earnings as reported	***$ 313***	*$ 1,116*	*$ 1,104*	***$ 2,524***	*$ 1,050*
Stock-based compensation expense (recovery), net of tax[a]	***120***	*(92)*	*75*	***95***	*481*
Unrealized risk management (gain) loss, net of tax[b]	***(166)***	*(496)*	*(583)*	***(674)***	*607*
Unrealized foreign exchange loss (gain), net of tax[c]	***145***	*9*	*5*	***114***	*(85)*
Effect of statutory tax rate changes on future income tax liabilities[d]	***-***	*(67)*	*-*	***(395)***	*(19)*
Adjusted net earnings from operations	***$ 412***	*$ 470*	*$ 601*	***$ 1,664***	*$ 2,034*

(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 future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. Income tax rate changes during 2006 resulted in a reduction of future income tax liabilities of approximately $438 million in North America, an increase of future income tax liabilities of approximately $110 million in the UK North Sea and a reduction of future income tax liabilities of approximately $67 million in Côte d'Ivoire. During 2005, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million.

(3) 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			Year Ended	
($ millions)	***Dec 31 2006***	*Sep 30 2006*	*Dec 31 2005*	***Dec 31 2006***	*Dec 31 2005*
Net earnings	***$ 313***	*$ 1,116*	*$ 1,104*	***$ 2,524***	*$ 1,050*
Non-cash items:					
Depletion, depreciation and amortization	***724***	*589*	*550*	***2,391***	*2,013*
Asset retirement obligation accretion	***18***	*17*	*16*	***68***	*69*
Stock-based compensation expense (recovery)	***176***	*(135)*	*125*	***139***	*723*
Unrealized risk management (gain) loss	***(241)***	*(754)*	*(825)*	***(1,013)***	*925*
Unrealized foreign exchange loss (gain)	***171***	*11*	*5*	***134***	*(103)*
Deferred petroleum revenue tax (recovery) expense	***(3)***	*(4)*	*1*	***37***	*(9)*
Future income tax expense	***135***	*473*	*514*	***652***	*353*
Cash flow from operations	***$ 1,293***	*$ 1,313*	*$ 1,490*	***$ 4,932***	*$ 5,021*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the year ended December 31, 2006, the Company reported record net earnings of $2,524 million compared to net earnings of $1,050 million for the year ended December 31, 2005. Net earnings for the year ended December 31, 2006 included unrealized after-tax income of $860 million related to the effects of risk management activities, statutory tax rate changes on future income tax liabilities, fluctuations in foreign exchange rates and stock-based compensation expense, compared to $984 million of net after-tax expenses for the year ended December 31, 2005. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2006 decreased to $1,664 million from $2,034 million for the year ended December 31, 2005, primarily due to decreased natural gas pricing, increased realized risk management losses on crude oil, increased production expense 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 benchmark crude oil pricing and increased crude oil and NGLs and natural gas sales volumes.

Fourth quarter 2006 net earnings were $313 million compared to net earnings of $1,104 million in the fourth quarter of 2005 and net earnings of $1,116 million in the prior quarter. Net earnings in the fourth quarter of 2006 included unrealized after-tax expenses of $99 million related to the effects of risk management activities, fluctuations in foreign exchange rates and stock-based compensation expense, compared to net after-tax income of $503 million in the fourth quarter of 2005 and $646 million of after-tax income in the prior quarter. Excluding these items, adjusted net earnings from operations in the fourth quarter of 2006 decreased to $412 million from $601 million in the comparable period in 2005, and decreased from $470 million in the prior quarter. The decrease from the comparable period in 2005 was primarily due to decreased natural gas pricing, increased Company-wide production expense, increased depletion, depreciation and amortization expense and the impact of a stronger Canadian dollar relative to the US dollar. These factors were partially offset by the impact of increased crude oil pricing, increased crude oil and NGLs and natural gas sales volumes and decreased realized risk management losses on crude oil. The decrease from the prior quarter was primarily due to decreased crude oil and NGLs pricing and increased depletion, depreciation and amortization expense, partially offset by increased natural gas pricing, increased crude oil and NGLs and natural gas sales volumes and decreased realized risk management losses. Operating results in the fourth quarter of 2006 were impacted by the acquisition of Anadarko Canada Corporation ("ACC") completed in November 2006. The Company completed the acquisition of ACC, a subsidiary of Anadarko Petroleum Corporation, for net cash consideration of $4,641 million including working capital and other adjustments. Substantially all of ACC's land and production base is located in Western Canada and consists of natural gas weighted assets. The operating results of ACC have been consolidated with the results of the Company effective November 2006. This acquisition increased fourth quarter 2006 sales volumes by approximately 44,800 boe/d. Natural gas production from the ACC properties averaged 354 mmcf/d for the two months of November and December.

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.

The Company's 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 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. 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 65% of expected crude oil volumes and approximately 75% of expected natural gas volumes have been hedged for 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for 2007 at a strike price of US$60.00 per barrel. The Company is extending its hedge program into 2008 whereby 150,000 bbl/d of crude oil volumes have been hedged (100,000 bbl/d of price collars with a US$60.00 floor and 50,000 bbl/d of put options with a US$55.00 strike price). In addition, 900,000 GJ/d of natural gas volumes have been hedged through the use of price collars for the first quarter of 2008 (400,000 GJ/d with a floor of $7.00 and 500,000 GJ/d with a floor of $7.50).

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 asset reflects, at December 31, 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 December 31, 2006.

Due to the changes in crude oil and natural gas forward pricing, and the reversal of prior year unrealized losses, the Company recorded a net unrealized gain of $1,013 million ($674 million after-tax) on its risk management activities for the year ended December 31, 2006, including an unrealized gain of $241 million ($166 million after-tax) for the three months ended December 31, 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 $139 million ($95 million after-tax) stock-based compensation expense for the year ended December 31, 2006 in connection with the 8% increase in the Company's share price, and a $176 million ($120 million after-tax) stock-based compensation expense as a result of the 22% increase in the Company's share price for the three months ended December 31, 2006 (Company's share price as at: December 31, 2006 - C$62.15; September 30, 2006 - C$50.94; December 31, 2005 - C$57.63). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period, 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 reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2006. In periods when substantial share 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 year ended December 31, 2006 decreased slightly to $4,932 million from $5,021 million for the year ended December 31, 2005. The decrease was primarily due to decreased natural gas pricing, increased realized risk management losses, increased production expense and the impact of a stronger Canadian dollar relative to the US dollar. These factors were partially offset by stronger benchmark crude oil pricing and increased crude oil and NGLs and natural gas sales volumes.

Cash flow from operations in the fourth quarter of 2006 decreased to $1,293 million from $1,490 million for the fourth quarter of 2005 and $1,313 million in the prior quarter. The decrease from the fourth quarter of 2005 was primarily due to decreased natural gas pricing, increased production expense 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, increased crude oil and NGLs and natural gas sales volumes and decreased realized risk management losses.

Total production before royalties increased 5% to average a record 580,724 boe/d for the year ended December 31, 2006 from 552,960 boe/d for the year ended December 31, 2005. Production for the fourth quarter of 2006 increased 6% to 613,764 boe/d from 577,505 boe/d in the fourth quarter of 2005 and increased 9% from 561,152 boe/d in the prior quarter.

The increase in crude oil and NGLs production for the year and three months ended December 31, 2006 from the comparable periods reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, additional production volumes as a result of the ACC acquisition, development of West and East Espoir and the full year's impact of production from the Baobab Field located offshore Côte d'Ivoire. Production from the Baobab Field commenced August 2005.

The increase in natural gas production for the year and three months ended December 31, 2006 from the comparable periods primarily reflected additional natural gas production as a result of the ACC acquisition. Natural gas production from the ACC properties averaged 354 mmcf/d for the two months of November and December. The increase was partially offset by declining production due to the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to sustained low natural gas prices and inflationary cost pressures.

OPERATING HIGHLIGHTS

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 47.27**	$ 62.55	$ 46.38	**$ 53.65**	$ 46.86
Royalties	**4.10**	5.11	3.89	**4.48**	3.97
Production expense	**12.32**	13.47	10.33	**12.29**	11.17
Netback	**$ 30.85**	$ 43.97	$ 32.16	**$ 36.88**	$ 31.72
Natural gas ($/mcf) (1)					
Sales price (2)	**$ 6.66**	$ 5.83	$ 11.67	**$ 6.72**	$ 8.57
Royalties	**1.26**	1.11	2.30	**1.29**	1.75
Production expense	**0.86**	0.84	0.76	**0.82**	0.73
Netback	**$ 4.54**	$ 3.88	$ 8.61	**$ 4.61**	$ 6.09
Barrels of oil equivalent ($/boe) (1)					
Sales price (2)	**$ 43.91**	$ 51.21	$ 56.08	**$ 47.92**	$ 48.77
Royalties	**5.62**	5.75	8.01	**5.89**	6.82
Production expense	**9.16**	10.01	7.93	**9.14**	8.21
Netback	**$ 29.13**	$ 35.45	$ 40.14	**$ 32.89**	$ 33.74

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

(2) Net of transportation and blending costs and excluding risk management activities.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
WTI benchmark price (US$/bbl)	**$ 60.21**	$ 70.55	$ 60.04	**$ 66.25**	$ 56.61
Dated Brent benchmark price (US$/bbl)	**$ 59.68**	$ 69.58	$ 56.93	**$ 65.18**	$ 54.45
Differential to LLB blend (US$/bbl)	**$ 21.31**	$ 19.08	$ 24.09	**$ 21.69**	$ 20.83
LLB blend differential from WTI (%)	**35%**	27%	40%	**33%**	37%
Condensate benchmark price (US$/bbl)	**$ 59.59**	$ 70.26	$ 60.41	**$ 66.24**	$ 57.25
NYMEX benchmark price (US$/mmbtu)	**$ 6.61**	$ 6.52	$ 12.83	**$ 7.26**	$ 8.56
AECO benchmark price (C$/GJ)	**$ 6.03**	$ 5.72	$ 11.07	**$ 6.62**	$ 8.05
US / Canadian dollar average exchange rate (US$)	**0.8781**	0.8919	0.8523	**0.8818**	0.8253

Commodity Prices

World benchmark crude oil prices increased during the first part of the year due to ongoing demand growth and geopolitical uncertainties. However, pricing significantly declined later in the year, reflecting high crude oil inventories. In December 2006 West Texas Intermediate ("WTI") averaged US$62.09 per bbl, a decline of 21% from the record high of US$78.40 per bbl reached in July 2006. WTI averaged US$66.25 per bbl for the year ended December 31, 2006, an increase of 17% compared to US$56.61 per bbl for the year ended December 31, 2005. In the fourth quarter of 2006, WTI averaged US$60.21 per bbl, up slightly from US$60.04 per bbl in the comparable period in 2005, and decreased 15% from US$70.55 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 33% for the year ended December 31, 2006 compared to 37% for the year ended December 31, 2005. In the fourth quarter of 2006, Heavy Differentials averaged 35% compared to 40% for the fourth quarter of 2005, but widened compared to the prior quarter. The narrowing of the Heavy Differentials from the comparable periods in 2005 was primarily due to reduced availability of imported grades from Venezuela and Mexico, reduced Canadian production of heavy crude oil and the removal of logistical constraints in accessing new markets in the US Gulf Coast due to the Pegasus and Spearhead pipelines commencing operations during 2006. The widening of the Heavy Differentials from the prior quarter reflected reduced seasonal demand for asphalt products. The increase in realized crude oil prices from the comparable periods in 2005 was partially offset by the negative 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 inventory levels remain high and given the unpredictable nature of geopolitical events.

Dated Brent ("Brent") averaged US$65.18 per bbl for the year ended December 31, 2006, an increase of 20% compared to US$54.45 per bbl for the year ended December 31, 2005. In the fourth quarter of 2006, Brent averaged US$59.68 per bbl, an increase of 5% from US$56.93 per bbl in the comparable period in 2005 and decreased 14% from US$69.58 per bbl in the prior quarter. Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Brent pricing, which benefited from strong European and Asian demand in 2006.

NYMEX natural gas prices averaged US$7.26 per mmbtu for the year ended December 31, 2006, a decrease of 15% from US$8.56 per mmbtu for the year ended December 31, 2005. In the fourth quarter of 2006, the NYMEX natural gas price decreased 48% to average US$6.61 per mmbtu from US$12.83 per mmbtu in the comparable period in 2005, and increased marginally from US$6.52 per mmbtu in the prior quarter. AECO natural gas pricing for the year ended December 31, 2006 decreased 18% from the year ended December 31, 2005 to average C$6.62 per GJ. AECO natural gas pricing for the fourth quarter of 2006 decreased 46% from the comparable period in 2005 and increased 5% from the prior quarter to average C$6.03 per GJ. The decrease in natural gas pricing in 2006 from the comparable periods in

2005 reflected the impact of exceptionally mild winter weather and reduced heating demand, relatively stable summer weather and reduced cooling demand and the continuing impact of high natural gas inventory levels.

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

Operating and Capital Costs

Strong commodity prices in recent years have resulted in increased demand and costs for oilfield services worldwide. This has lead to inflationary production and capital cost pressures throughout the North America oil and gas industry, particularly related to natural gas drilling activity and oil sands developments. The strong commodity price environment has also impacted costs in international basins. Specifically, the high demand for offshore drilling rigs continues and securing rigs on commercially acceptable terms is an ongoing challenge.

The oil and gas industry is also experiencing cost pressures related to increasingly stringent environmental regulations, both in North America and internationally. In addition, environmental regulations in Canada intended to reduce greenhouse gas emissions are pending and the impact of the legislation is uncertain at this time.

These increased cost pressures and environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects.

PRODUCT PRICES [(1)]

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Crude oil and NGLs ($/bbl) [(2)]					
North America	**$ 40.27**	$ 55.97	$ 37.96	**$ 46.52**	$ 39.62
North Sea	**$ 67.72**	$ 78.68	$ 66.88	**$ 72.62**	$ 66.57
Offshore West Africa	**$ 63.50**	$ 70.59	$ 60.19	**$ 67.99**	$ 59.91
Company average	**$ 47.27**	$ 62.55	$ 46.38	**$ 53.65**	$ 46.86
Natural gas ($/mcf) [(2)]					
North America	**$ 6.70**	$ 5.86	$ 11.79	**$ 6.77**	$ 8.65
North Sea	**$ 3.48**	$ 2.38	$ 3.40	**$ 2.66**	$ 3.17
Offshore West Africa	**$ 5.72**	$ 4.97	$ 5.13	**$ 5.37**	$ 5.91
Company average	**$ 6.66**	$ 5.83	$ 11.67	**$ 6.72**	$ 8.57
Company average ($/boe) [(2)]	**$ 43.91**	$ 51.21	$ 56.08	**$ 47.92**	$ 48.77
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**60%**	72%	48%	**64%**	54%
Natural gas	**40%**	28%	52%	**36%**	46%

(1) Net of transportation and blending 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 14% to average $53.65 per bbl for the year ended December 31, 2006 from $46.86 per bbl for the year ended December 31, 2005. Realized crude oil prices for the fourth quarter of 2006 averaged $47.27 per bbl, a marginal increase from $46.38 per bbl in the fourth quarter of 2005, and decreased 24% from $62.55 per bbl in the prior quarter. The increase for the year ended December 31, 2006 from the year ended December 31, 2005 was due to increased benchmark crude oil prices and a narrower Heavy Differential, partially offset by the impact of a stronger Canadian dollar. The decrease in the fourth quarter of 2006 from the prior quarter primarily reflected decreased benchmark crude oil prices and higher crude oil inventories, and the widening Heavy Differential in Canada due to reduced seasonal demand for asphalt products.

The Company's realized natural gas price decreased 22% to average $6.72 per mcf for the year ended December 31, 2006 from $8.57 per mcf for the year ended December 31, 2005. In the fourth quarter of 2006, the Company's realized natural gas price decreased 43% from $11.67 per mcf in the fourth quarter of 2005 but increased 14% from $5.83 per mcf in the prior quarter. The decrease from the comparable periods in 2005 reflected record levels of natural gas inventory in North America, primarily due to the impact of exceptionally mild winter weather in 2006 that reduced heating demand and relatively stable summer weather that reduced cooling demand. The increase from the prior quarter reflected seasonal pricing increases due to heating demand.

North America

North America realized crude oil prices increased 17% to average $46.52 per bbl for the year ended December 31, 2006 from $39.62 per bbl for the year ended December 31, 2005. Realized crude oil prices in the fourth quarter of 2006 averaged $40.27 per bbl, a 6% increase from $37.96 per bbl in the comparable period in 2005, and decreased 28% from $55.97 per bbl in the prior quarter. The increase from the comparable periods in 2005 was due to increased benchmark crude oil prices and a narrower Heavy Differential, partially offset by the impact of a stronger Canadian dollar. The decrease in the fourth quarter of 2006 from the prior quarter primarily reflected decreased benchmark crude oil prices and higher crude oil inventories, and the widening Heavy Differential due to reduced seasonal demand.

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 fourth quarter, the Company contributed approximately 135,000 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 22% to average $6.77 per mcf for the year ended December 31, 2006 from $8.65 per mcf for the year ended December 31, 2005. The realized natural gas price in the fourth quarter of 2006 averaged $6.70 per mcf, a decrease of 43% from $11.79 per mcf in the fourth quarter of 2005, and increased 14% from $5.86 per mcf in the prior quarter. The decrease from the comparable periods in 2005 was primarily due to reduced winter heating demand and reduced summer cooling demand in 2006.

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

	Dec 31 2006	Sep 30 2006	Dec 31 2005
Wellhead Price (1) (2)			
Light / medium crude oil and NGLs (C$/bbl)	**$ 54.11**	$ 72.25	$ 61.33
Pelican Lake crude oil (C$/bbl)	**$ 37.89**	$ 53.84	$ 34.86
Primary heavy crude oil (C$/bbl)	**$ 36.16**	$ 52.15	$ 31.00
Thermal heavy crude oil (C$/bbl)	**$ 36.06**	$ 50.36	$ 28.84
Natural gas (C$/mcf)	**$ 6.70**	$ 5.86	$ 11.79

(1) Net of transportation and blending 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 9% to average $72.62 per bbl for the year ended December 31, 2006 from $66.57 per bbl for the year ended December 31, 2005. Realized crude oil prices in the fourth quarter of 2006 increased marginally to average $67.72 per bbl from $66.88 per bbl in the fourth quarter of 2005 and decreased 14% from $78.68 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 in 2006 compared to 2005. The decrease from the prior quarter primarily reflected decreased benchmark crude oil prices and higher crude oil inventories.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 13% to average $67.99 per bbl for the year ended December 31, 2006 from $59.91 per bbl for the year ended December 31, 2005. Realized crude oil prices for the fourth quarter of 2006 increased 5% to average $63.50 per bbl from $60.19 per bbl in the fourth quarter of 2005 and decreased 10% from $70.59 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 primarily reflected decreased benchmark crude oil prices and higher crude oil inventories.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. The related life-to-date crude oil inventory volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**Dec 31 2006**	Sep 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	**910,796**	243,635	747,141
Offshore West Africa, related to timing of liftings	**113,774**	711,096	412,841
	2,122,096	2,052,257	1,644,139

In the fourth quarter of 2006, net sales of approximately 70,000 barrels of crude oil produced in the Company's international operations were deferred and excluded from the fourth quarter results of operations. This change in crude oil inventory volumes increased cash flow from operations by approximately $15 million in the fourth quarter of 2006, due to the increase in higher netback Offshore West Africa sales volumes, partially offset by the decrease in lower netback North Sea sales volumes.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Crude oil and NGLs (bbl/d)					
North America	**249,565**	233,440	230,263	**235,253**	221,669
North Sea	**61,786**	53,988	66,798	**60,056**	68,593
Offshore West Africa	**32,354**	34,237	43,207	**36,689**	22,906
	343,705	321,665	340,268	**331,998**	313,168
Natural gas (mmcf/d)					
North America	**1,594**	1,416	1,402	**1,468**	1,416
North Sea	**16**	11	15	**15**	19
Offshore West Africa	**10**	10	6	**9**	4
	1,620	1,437	1,423	**1,492**	1,439
Total barrel of oil equivalent (boe/d)	**613,764**	561,152	577,505	**580,724**	552,960
Product mix					
Light/medium crude oil and NGLs	**24%**	24%	28%	**26%**	26%
Pelican Lake crude oil	**5%**	5%	5%	**5%**	4%
Primary heavy crude oil	**15%**	16%	17%	**16%**	17%
Thermal heavy crude oil	**12%**	12%	9%	**11%**	10%
Natural gas	**44%**	43%	41%	**42%**	43%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Crude oil and NGLs (bbl/d)					
North America	**217,751**	205,087	198,047	**205,382**	191,751
North Sea	**61,658**	53,911	66,664	**59,940**	68,487
Offshore West Africa	**30,817**	31,864	42,081	**35,212**	22,293
	310,226	290,862	306,792	**300,534**	282,531
Natural gas (mmcf/d)					
North America	**1,291**	1,144	1,124	**1,185**	1,125
North Sea	**16**	11	15	**15**	18
Offshore West Africa	**9**	9	6	**9**	4
	1,316	1,164	1,145	**1,209**	1,147
Total barrel of oil equivalent (boe/d)	**529,515**	484,872	497,679	**502,024**	473,742

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 also presented.

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 production averaged a record 580,724 boe/d for the year ended December 31, 2006, a 5% increase from the year ended December 31, 2005. Fourth quarter total production in 2006 averaged a record 613,764 boe/d, an increase of 6% from the fourth quarter of 2005 and an increase of 9% from the prior quarter. The increase in crude oil and NGLs production from the comparable periods in 2005 and the prior quarter reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, additional production volumes from the ACC acquisition, development of West and East Espoir and the full year's impact of production from the Baobab Field located offshore Côte d'Ivoire. Production from the Baobab Field commenced August 2005. The increase in natural gas production from the comparable periods in 2005 and the prior quarter primarily reflected additional natural gas production from the ACC acquisition. The increase was partially offset by the production decrease due to the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to sustained low natural gas prices and inflationary cost pressures.

Total crude oil and NGLs production for the year ended December 31, 2006 increased 6% to 331,998 bbl/d from 313,168 bbl/d for the year ended December 31, 2005. In the fourth quarter of 2006, production increased slightly to 343,705 bbl/d from 340,268 bbl/d in the fourth quarter of 2005 and increased 7% from 321,665 bbl/d in the prior quarter. Crude oil and NGLs production in the fourth quarter of 2006 was on the high end of the Company's previously issued guidance of 324,000 to 344,000 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 year ended December 31, 2006 averaged 1,492 mmcf/d compared to 1,439 mmcf/d for the year ended December 31, 2005. In the fourth quarter of 2006, natural gas production increased 14% to average 1,620 mmcf/d from 1,423 mmcf/d in the fourth quarter of 2005 and increased 13% from 1,437 mmcf/d in the prior quarter. Fourth quarter natural gas production was at the low end of the Company's previously issued guidance of 1,620 to 1,658 mmcf/d, primarily due to the impact of the Company's decision to reduce natural gas drilling activity in 2006 in response to inflationary costs in western Canada.

In 2007, annual production is forecasted to average between 315,000 and 360,000 bbl/d of crude oil and NGLs and between 1,594 and 1,664 mmcf/d of natural gas. First quarter 2007 production guidance is forecasted to average between 315,000 and 331,000 bbl/d of crude oil and NGLs and between 1,696 and 1,717 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the year ended December 31, 2006 increased 6% to average 235,253 bbl/d from 221,669 bbl/d for the year ended December 31, 2005. Production in the fourth quarter of 2006 increased 8% to average 249,565 bbl/d from 230,263 bbl/d in the fourth quarter of 2005 and increased 7% from 233,440 bbl/d in the prior quarter. The increase in crude oil and NGLs production from the comparable periods in 2005 and the prior quarter was primarily due to increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project and the ACC acquisition.

North America natural gas production averaged 1,468 mmcf/d for the year ended December 31, 2006, an increase of 4% from 1,416 mmcf/d for the year ended December 31, 2005. Fourth quarter 2006 production increased 14% to average 1,594 mmcf/d from 1,402 mmcf/d in the fourth quarter of 2005 and increased 13% from 1,416 mmcf/d in the prior quarter. The increase in natural gas production from the comparable periods in 2005 and the prior quarter reflected November and December natural gas production from the ACC acquisition, partially offset by production declines due to the Company's decision to reduce natural gas drilling activity. The ACC acquisition was completed in November with results included from that date. To date, the ACC properties are performing as expected.

North Sea

North Sea crude oil production for the year ended December 31, 2006 averaged 60,056 bbl/d, a 12% decrease from 68,593 bbl/d for the year ended December 31, 2005. Crude oil production in the fourth quarter of 2006 decreased 8% to average 61,786 bbl/d from 66,798 bbl/d in the comparable period in 2005, and increased 14% from the prior quarter production of 53,988 bbl/d. Production levels for the fourth quarter were in line with expectations, reflecting the production effects of planned maintenance shutdowns in the third quarter of 2006.

Offshore West Africa

Offshore West Africa crude oil production for the year ended December 31, 2006 increased 60% to 36,689 bbl/d from 22,906 bbl/d for the year ended December 31, 2005. Production during the fourth quarter of 2006 decreased 25% from 43,207 bbl/d in the fourth quarter of 2005 and decreased 5% from the prior quarter. The increase from the year ended December 31, 2005 was primarily due to the impact of a full year's production from the Baobab Field, first crude oil from West Espoir and a successful infill drilling campaign at East Espoir. The increase was partially offset by continuing challenges with sand and solids production at the Baobab Field that resulted in the shut in of 5 production wells. The Company does not plan to recomplete these wells until such time as a deepwater rig can be secured on commercially acceptable terms.

ROYALTIES

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 5.13**	$ 6.79	$ 5.39	**$ 5.86**	$ 5.37
North Sea	**$ 0.14**	$ 0.11	$ 0.14	**$ 0.13**	$ 0.10
Offshore West Africa	**$ 3.02**	$ 4.89	$ 1.57	**$ 2.81**	$ 1.62
Company average	**$ 4.10**	$ 5.11	$ 3.89	**$ 4.48**	$ 3.97
Natural gas ($/mcf) [(1)]					
North America	**$ 1.29**	$ 1.12	$ 2.34	**$ 1.31**	$ 1.78
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.27**	$ 0.34	$ 0.14	**$ 0.22**	$ 0.16
Company average	**$ 1.26**	$ 1.11	$ 2.30	**$ 1.29**	$ 1.75
Company average ($/boe) [(1)]	**$ 5.62**	$ 5.75	$ 8.01	**$ 5.89**	$ 6.82
Percentage of revenue [(2)]					
Crude oil and NGLs	**9%**	8%	8%	**8%**	8%
Natural gas	**19%**	19%	20%	**19%**	20%
Company average boe	**13%**	11%	14%	**12%**	14%

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

(2) Net of transportation and blending costs and excluding risk management activities.

North America

North America crude oil and NGL royalties per bbl for the year and three months ended December 31, 2006 were primarily a reflection of increased realized crude oil prices and the full recovery of the Company's capital investments in the Primrose North and South Fields in the third quarter of 2006. Upon full recovery, Crown royalty rates on the Primrose North and South Fields increased from 1% of gross revenue to 25% of gross revenue less operating, capital and abandonment costs. North America crude oil and NGL royalties averaged approximately 13% of gross revenues in 2006. Crude oil and NGLs royalties per bbl are anticipated to be 14% to 16% of gross revenues in 2007.

Natural gas royalties per mcf decreased from the comparable periods in 2005 and increased from the prior quarter in line with benchmark natural gas prices. Benchmark natural gas prices in 2006 decreased from the comparable periods in 2005 primarily in response to reduced demand and increased storage levels. Strengthening benchmark natural gas prices in the fourth quarter of 2006 resulted in increased natural gas royalties. North America natural gas royalties averaged approximately 19% in 2006 and are anticipated to be 21% to 23% of gross revenues in 2007.

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. The Company's capital investments in the Espoir Field are expected to be fully recovered in the first quarter of 2007, increasing royalty rates and current income taxes in accordance with the PSCs. The Company's capital investments in the Baobab Field are now not expected to be fully recovered until approximately 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 that were effective January 1, 2006, royalty rates as a percentage of gross revenue increased from approximately 3% in 2005 to approximately 4% in 2006. As a result, production volumes net of royalties decreased approximately 2% in 2006 from 2005, in accordance with the terms of the PSC's. Royalty rates in 2007 are anticipated to be 13% to 15% of gross revenue due to the Company's expected full recovery of its capital investments in the Espoir Field.

PRODUCTION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 12.13**	$ 12.05	$ 10.92	**$ 11.73**	$ 10.49
North Sea	**$ 14.76**	$ 20.28	$ 12.11	**$ 17.57**	$ 14.94
Offshore West Africa	**$ 10.05**	$ 7.97	$ 5.62	**$ 7.45**	$ 6.50
Company average	**$ 12.32**	$ 13.47	$ 10.33	**$ 12.29**	$ 11.17
Natural gas ($/mcf) [(1)]					
North America	**$ 0.84**	$ 0.83	$ 0.74	**$ 0.81**	$ 0.71
North Sea	**$ 1.54**	$ 1.30	$ 1.96	**$ 1.40**	$ 2.44
Offshore West Africa	**$ 2.01**	$ 1.39	$ 0.80	**$ 1.19**	$ 1.05
Company average	**$ 0.86**	$ 0.84	$ 0.76	**$ 0.82**	$ 0.73
Company average ($/boe) [(1)]	**$ 9.16**	$ 10.01	$ 7.93	**$ 9.14**	$ 8.21

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2006 increased to $11.73 per bbl from $10.49 per bbl for the year ended December 31, 2005. Crude oil and NGLs production expense for the fourth quarter of 2006 increased to $12.13 per bbl from $10.92 per bbl for the fourth quarter of 2005 and increased marginally from $12.05 per bbl in the prior quarter. The increase in production expense from the comparable periods in 2005 was primarily due to increased industry wide service costs. Production expense in the fourth quarter of 2006 compared to the fourth quarter of 2005 and the prior quarter also reflected increased cyclic steaming costs related to the Company's thermal crude oil projects due to the timing of secondary steaming cycles.

North America natural gas production expense per mcf for the year and three months ended December 31, 2006 increased over the comparable periods in 2005 due to increased cost pressures, but was comparable to the prior quarter.

On a total boe basis, North America fourth quarter production expense of $8.49 per bbl was unchanged from the prior quarter primarily due to the increased percentage of lower cost natural gas sales volumes attributable to the ACC acquisition, offset by the increased percentage of higher cost thermal crude oil sales volumes. Production expense per boe in 2007 is anticipated to continue to reflect industry wide inflationary cost pressures.

North Sea

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

Offshore West Africa

Offshore West Africa crude oil production expense on a per barrel basis increased from the comparable periods in 2005 and the prior quarter primarily due to continuing operating challenges with sand and solids resulting in decreased production volumes at Baobab, on a relatively fixed operating cost base.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2006**	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Revenue	**$ 18**	$ 19	$ 21	**$ 72**	$ 77
Production expense	**6**	6	8	**23**	24
Midstream cash flow	**12**	13	13	**49**	53
Depreciation	**2**	2	2	**8**	8
Segment earnings before taxes	**$ 10**	$ 11	$ 11	**$ 41**	$ 45

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			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Expense ($ millions)	**$ 722**	$ 587	$ 548	**$ 2,383**	$ 2,005
$/boe (2)	**$ 12.80**	$ 10.89	$ 10.44	**$ 11.27**	$ 10.02

(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 year and three months ended December 31, 2006 increased in total and on a boe basis from the comparable periods in 2005 and the prior quarter. The increase was primarily as a result of increased production combined with overall increases in finding and development costs associated with crude oil and natural gas exploration in North America, a higher depletion base due to the ACC acquisition, and increased estimated future costs to develop the Company's proved undeveloped reserves.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Expense ($ millions)	**$ 18**	$ 17	$ 16	**$ 68**	$ 69
$/boe (1)	**$ 0.32**	$ 0.31	$ 0.30	**$ 0.32**	$ 0.34

(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 for the year and three months ended December 31, 2006 was consistent with the prior periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2006	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Net expense ($ millions)	**$ 57**	$ 41	$ 36	**$ 180**	$ 151
$/boe (1)	**$ 1.01**	$ 0.76	$ 0.68	**$ 0.85**	$ 0.75

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

Administration expense for the year and three months ended December 31, 2006 increased in total and on a boe basis from the comparable periods, primarily due to increased insurance premiums, increased staffing and administrative costs, costs associated with the integration of ACC, and overall inflationary pressures.

STOCK-BASED COMPENSATION EXPENSE (RECOVERY)

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2006**	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Stock option plan expense (recovery)	**$ 176**	$ (135)	$ 125	**$ 139**	$ 723

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 $139 million ($95 million after-tax) stock-based compensation expense for the year ended December 31, 2006 in connection with the 8% increase in the Company’s share price, and a $176 million ($120 million after-tax) stock-based compensation expense as a result of the 22% increase in the Company’s share price in the fourth quarter of 2006 (Company’s share price as at: December 31, 2006 - C$62.15; September 30, 2006 - C$50.94; December 31, 2005 - C$57.63). As required by GAAP, the Company’s outstanding stock options are valued each reporting period 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 year ended December 31, 2006, the Company capitalized $79 million in stock-based compensation on the Horizon Project (December 31, 2005 - $101 million). The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2006. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2006, the Company paid $264 million for stock options surrendered for cash settlement (December 31, 2005 - $227 million).

INTEREST EXPENSE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2006**	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Interest expense, gross	**$ 128**	$ 81	$ 55	**$ 336**	$ 221
Less: capitalized interest, Horizon Project	**66**	56	27	**196**	72
Interest expense, net	**$ 62**	$ 25	$ 28	**$ 140**	$ 149
$/boe (1)	**$ 1.08**	$ 0.48	$ 0.53	**$ 0.66**	$ 0.74
Average effective interest rate	**5.6%**	5.8%	5.7%	**5.7%**	5.6%

(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 increased debt levels associated with the ACC acquisition and the financing of Horizon Project capital expenditures. The increase from the comparable periods in 2005 was partially offset by the impact of the strengthening Canadian dollar, which decreased interest expense on the Company's US dollar denominated debt securities.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes. Changes in fair value of derivative financial instruments formally 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 fair value of derivative financial instruments not formally designated as hedges are recognized in the balance sheet each period with the offset reflected in risk management activities in the consolidated statements of earnings.

The Company formally documents all derivative financial instruments designated as 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. Realized gains or losses on these contracts are included in risk management activities. Unrealized gains or losses on commodity price contracts not formally documented as hedges are also 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. Gains or losses on interest rate swap contracts formally designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

The Company enters into cross-currency swap agreements to manage currency exposure on US dollar 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 the foreign exchange component of all cross-currency swap contracts are included in risk management activities. Gains or losses on the interest component of cross-currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of derivative 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 transaction 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 **Dec 31 2006**	Sep 30 2006	Dec 31 2005	Year Ended **Dec 31 2006**	Dec 31 2005
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 223**	$ 419	$ 235	**$ 1,395**	$ 753
Natural gas financial instruments	**(97)**	(15)	242	**(70)**	283
Interest rate swaps	**-**	-	(1)	**-**	(9)
	$ 126	$ 404	$ 476	**$ 1,325**	$ 1,027
Unrealized (gain) loss					
Crude oil and NGLs financial instruments	**$ (239)**	$ (601)	$ (514)	**$ (736)**	$ 847
Natural gas financial instruments	**8**	(152)	(307)	**(260)**	77
Interest rate and cross-currency swaps	**(10)**	(1)	(4)	**(17)**	1
	$ (241)	$ (754)	$ (825)	**$ (1,013)**	$ 925
Total	**$ (115)**	$ (350)	$ (349)	**$ 312**	$ 1,952

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 **Dec 31 2006**	Sep 30 2006	Dec 31 2005	Year Ended **Dec 31 2006**	Dec 31 2005
Crude oil and NGLs ($/bbl)[(1)]	**$ 7.09**	$ 13.15	$ 7.67	**$ 11.57**	$ 6.68
Natural gas ($/mcf)[(1)]	**$ (0.65)**	$ (0.11)	$ 1.85	**$ (0.13)**	$ 0.54

(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 asset reflected, at December 31, 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 December 31, 2006. Due to changes in the crude oil and natural gas forward pricing, and the reversal of prior year unrealized losses, the Company recorded a net unrealized gain of $1,013 million ($674 million after-tax) on its risk management activities for the year ended December 31, 2006 (December 31, 2005 - unrealized loss of $925 million, $607 million after-tax), including an unrealized gain of $241 million ($166 million after-tax) for the three months ended December 31, 2006 (December 31, 2005 - unrealized gain of $825 million, $583 million after-tax; September 30, 2006 - unrealized gain of $754 million, $496 million after-tax).

In addition to the net risk management asset recognized on the balance sheet at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million (December 31, 2005 – net unrecognized liability of $990 million).

Details related to outstanding derivative financial instruments at December 31, 2006 are disclosed in note 10 to the Company’s unaudited interim consolidated financial statements.

Effective January 1, 2007, the Company will adopt new accounting standards relating to the accounting for and disclosure of financial instruments. In 2007, the Company will record all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. Designated hedges are currently not recognized on the balance sheet but are disclosed in the notes to the consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2006**	Sep 30 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Realized foreign exchange (gain) loss	**$ (20)**	$ 1	$ (16)	**$ (12)**	$ (29)
Unrealized foreign exchange loss (gain)	**171**	11	5	**134**	(103)
	$ 151	$ 12	$ (11)	**$ 122**	$ (132)

The Company's operating results are affected by fluctuations in 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 decreased 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 increased 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 gain for the year and three months ended December 31, 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 for the year and three months ended December 31, 2006 was primarily related to the fourth quarter weakening 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 fourth quarter at US$0.8581 compared to US$0.8577 at December 31, 2005 (September 30, 2006 - US$0.8966).

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 **Dec 31 2006**	Sep 30 2006	Dec 31 2005	Year Ended **Dec 31 2006**	Dec 31 2005
Taxes other than income tax					
Current	**$ 44**	$ 81	$ 50	**$ 219**	$ 203
Deferred	**(3)**	(4)	1	**37**	(9)
	$ 41	$ 77	$ 51	**$ 256**	$ 194
Current income tax					
North America	**$ 51**	$ 52	$ 8	**$ 143**	$ 99
North Sea	**30**	-	31	**30**	155
Offshore West Africa	**14**	6	19	**49**	32
	$ 95	$ 58	$ 58	**$ 222**	$ 286
Future income tax expense	**$ 135**	$ 473	$ 514	**$ 652**	$ 353
Effective income tax rate	**42.3%**	32.2%(3)	34.1%	**25.7%(1)(2)(3)**	37.8%

(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 of 2006.

(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 of 2006.

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 future period. 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 in any particular year.

Income tax rate changes during 2006 resulted in a reduction of future income tax liabilities of approximately $438 million in North America, an increase of future income tax liabilities of approximately $110 million in the UK North Sea and a reduction of future income tax liabilities of approximately $67 million in Côte d'Ivoire.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Dec 31 2006**	Three Months Ended Sep 30 2006	Three Months Ended Dec 31 2005	Year Ended **Dec 31 2006**	Year Ended Dec 31 2005
Expenditures on property, plant and equipment					
Net property acquisitions (dispositions)	**$ 4,720**	$ (6)	$ 19	**$ 4,733**	$ (320)
Land acquisition and retention	**28**	29	97	**210**	254
Seismic evaluations	**17**	26	40	**130**	132
Well drilling, completion and equipping	**462**	524	629	**2,340**	2,000
Pipeline and production facilities	**311**	270	314	**1,314**	1,295
Total net reserve replacement expenditures	**5,538**	843	1,099	**8,727**	3,361
Horizon Project:					
Phase 1 construction costs [2]	**745**	727	469	**2,768**	1,249
Phases 2 and 3 costs	**54**	18	-	**79**	-
Capitalized interest, stock-based compensation and other [2]	**134**	39	88	**338**	250
Total Horizon Project	**933**	784	557	**3,185**	1,499
Midstream	**1**	2	1	**12**	4
Abandonments [3]	**19**	24	16	**75**	46
Head office	**6**	8	6	**26**	22
Total net capital expenditures	**$ 6,497**	$ 1,661	$ 1,679	**$ 12,025**	$ 4,932
By segment					
North America	**$ 5,296**	$ 667	$ 862	**$ 7,936**	$ 2,530
North Sea	**211**	148	118	**646**	387
Offshore West Africa	**30**	27	119	**134**	439
Other	**1**	1	-	**11**	5
Horizon Project	**933**	784	557	**3,185**	1,499
Midstream	**1**	2	1	**12**	4
Abandonments [3]	**19**	24	16	**75**	46
Head office	**6**	8	6	**26**	22
Total	**$ 6,497**	$ 1,661	$ 1,679	**$ 12,025**	$ 4,932

(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 concentrates 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 for the year ended December 31, 2006 were $12,025 million compared to $4,932 million in the year ended December 31, 2005. The increase primarily related to the $4,641 million[(1)] acquisition of ACC (including working capital and other adjustments) and the continued progress on the Company's larger, future growth projects, most notably the Horizon Project. Excluding ACC and the Horizon Project, net capital expenditures were $4,199 million in 2006 compared to $3,433 in 2005, reflecting the impact of $320 million in net property dispositions in 2005 and industry-wide inflationary pressures. In the year ended December 31, 2006, the Company drilled a total of 1,738 net wells consisting of 641 natural gas wells, 603 crude oil wells, 375 stratigraphic test and service wells, and 119 wells that were dry. The 375 stratigraphic test and service wells include 163 stratigraphic test wells related to the Horizon Project. This compared to 1,882 net wells drilled in the year ended December 31, 2005. The Company achieved an overall success rate of 91% for the year ended December 31, 2006, excluding the stratigraphic test and service wells (December 31, 2005 - 93%).

Excluding ACC acquisition expenditures of $4,641 million[(1)], net capital expenditures in the fourth quarter of 2006 were $1,856 million compared to $1,679 million in the comparable period in 2005 and $1,661 million in the prior quarter. In the fourth quarter of 2006, the Company drilled a total of 331 net wells consisting of 60 natural gas wells, 177 crude oil wells, 66 stratigraphic test and service wells and 28 wells that were dry. The Company achieved an overall success rate of 89% for the fourth quarter of 2006, excluding stratigraphic test and service wells.

(1) The preliminary allocation of the ACC purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

Summary of purchase price allocation:

Property, plant and equipment	*$*	***6,249***
Less – future income taxes		***(1,438)***
– asset retirement costs		***(56)***
Consideration for crude oil and natural gas properties	*$*	***4,755***
Non-cash working capital deficit assumed and other		***(105)***
Long-term debt assumed		***(9)***
Net purchase price - cash consideration	*$*	***4,641***

North America

North America, including the Horizon Project and the ACC acquisition, accounted for approximately 94% of the total capital expenditures for the year ended December 31, 2006 compared to approximately 83% for the year ended December 31, 2005.

During 2006, the Company targeted 732 net natural gas wells, including 181 wells in Northeast British Columbia, 262 wells in the Northern Plains region, 177 wells in Northwest Alberta, and 112 wells in the Southern Plains region. The Company also targeted 619 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 292 heavy crude oil wells, 144 Pelican Lake crude oil wells, and 8 light crude oil wells were drilled. Another 114 wells targeting light crude oil were drilled outside the Northern Plains as well as 61 thermal crude oil wells in the Company's In-Situ Oil Sands area. In the fourth quarter of 2006, the Company drilled 74 net wells targeting natural gas and 188 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 access its large crude oil drilling inventory to maximize value in both the short and long term. To optimize netbacks in the short term, the Company will continue to focus on drilling crude oil wells in 2007 and, accordingly, will reduce natural gas drilling activity to manage overall capital spending. Deferred natural gas wells will be retained in the

Company's prospect inventory, and will be drilled as natural gas commodity prices improve. Drilling on ACC acquired lands will be optimized as part of the overall capital program.

As part of the development of the Company's In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. At the end of 2006, the Company had drilled 186 stratigraphic test wells and observation wells and 61 thermal oil wells. With first steaming for the Primrose North expansion commencing in November 2005, overall Primrose thermal production in 2006 increased to approximately 64,000 bbl/d from 53,000 bbl/d in 2005. Initial steaming of the projects was completed in the fourth quarter of 2006.

In November of 2005, the Company announced a phased expansion of its In-Situ 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 40,000 bbl/d and received Board of Director's sanction in 2006. Detailed engineering and procurement is currently underway. The Company anticipates receiving regulatory approval for Primrose East in the first half of 2007, with drilling and construction planned to begin in the third quarter of 2007, and production expected to commence in 2009.

The next phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 km north of the existing Primrose facilities. The Kirby project is anticipated to add an additional 30,000 bbl/d of production growth. The Company is targeting to file its formal regulatory application documents for this project in the latter half of 2007. First steaming is anticipated to begin in 2011.

Development of new acreage and secondary recovery conversion projects at Pelican Lake continued as expected through 2006. Drilling consisted of 144 horizontal wells, with plans to drill 132 additional horizontal wells in 2007. The response from the polymer flood pilot continues to be positive. Based on the results of the pilot, the Company commenced the installation of 12 additional polymer skids in 2006 as part of the commercial polymer flood project. Pelican Lake production averaged approximately 30,000 bbl/d in 2006.

Originally announced in the fall of 2005, the Scoping Study for the Canadian Natural Upgrader continued during Q4/06 and into early 2007. The terms of reference for this study involved the evaluation of product alternatives, location, technology, gasification and integration with existing assets using the same disciplined approach utilized in the Horizon Project. The next steps in this process would include a Design Basis Memorandum ("DBM") and Engineering Design Specification ("EDS") which would be required to be completed prior to construction and sanctioning of the project by the Board of Directors.

Based upon the results of the Scoping Study, which identified growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

In the first quarter of 2007, the Company's overall drilling activity in North America is expected to be comprised of 241 natural gas wells and 199 crude oil wells excluding stratigraphic and service wells.

Horizon Project

The Horizon Project continued on schedule and on budget with construction 57% complete at year-end. The project status as at December 31, 2006 was as follows:

- Detailed engineering was 94% complete;
- Over $5.1 billion in purchase orders and contracts have been awarded to date;
- Several key mechanical contracts were awarded;
- Set 333 piperack modules;
- Mine overburden removal was approximately 35% complete; and
- Site preparation and underground infrastructure was completed.

Major activities for the first quarter of 2007 will include:

- Preparation of the high pressure natural gas piping for commissioning;
- Completion of the erection of the cooling tower; and
- Completion of the installation of the last 35kV substation.

The Company does not anticipate a material change from the budgeted $6.8 billion Phase 1 construction cost. First production of light, sweet Synthetic Crude Oil from Phase 1 construction is targeted to commence in the third quarter of 2008.

North Sea

In the fourth quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the quarter, 2.5 net wells were drilled, with an additional 2 net wells drilling at quarter end.

The development of the Lyell Field progressed during the fourth quarter with the completion of construction, installation and tie-in of subsea infrastructure. Tranche 1 of the Lyell Field development comprises the drilling of 4 net wells and the workover of 2 existing wells. Production from the Lyell Field is expected to be at full capacity by the third quarter of 2007.

During the fourth quarter, construction of the Columba E Raw Water Injection project continued. The project consists of 2 injection wells.

Offshore West Africa

During the fourth quarter of 2006, 1.8 net wells were drilled with 1 net well drilling at the end of the quarter.

First crude oil from West Espoir commenced from 2 wells brought on-line during the third quarter. In the fourth quarter 1 production well and 2 water injectors were added. 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, received Government approval of its development plan for this acquisition during the first quarter of 2006 and received Board sanction for development in November 2006. Development plans include a floating production, storage and offtake vessel (“FPSO”), handling production from 4 shallow-water producing platforms. During the fourth quarter of 2006 the Company signed a lease agreement for a FPSO with a primary term of ten years, commencing 2008.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2006**		Sep 30 2006		Dec 31 2005
Working capital deficit [1]	**$**	**832**	$	1,032	$	1,774
Long-term debt	**$**	**11,043**	$	5,500	$	3,321
Shareholders' equity						
Share capital	**$**	**2,562**	$	2,536	$	2,442
Retained earnings		**8,141**		7,869		5,804
Foreign currency translation adjustment		**(13)**		(12)		(9)
Total	**$**	**10,690**	$	10,393	$	8,237
Debt to book capitalization [2]		**50.8%**		34.6%		28.7%
Debt to market capitalization		**24.8%**		16.7%		9.7%
After tax return on average common shareholders' equity [3]		**26.9%**		38.2%		14.3%
After tax return on average capital employed [4]		**17.2%**		26.0%		10.4%

(1) Calculated as current assets less current liabilities.

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

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

(4) 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 December 31, 2006 consisted primarily of cash flow from operations, available credit facilities and access to debt 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 also dependent upon these factors, as well as 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 on commercially acceptable terms, will be sufficient to sustain its operations and support its growth strategy. The Company's current debt ratings are BBB (high) with a negative trend by DBRS, Baa2 with a stable outlook by Moody's Investor Services, Inc. and BBB with a stable outlook by Standard and Poors Corporation.

At December 31, 2006, the Company had undrawn bank lines of credit of $1,115 million. Details related to the Company's credit facilities outstanding at December 31, 2006 are disclosed in note 4 to the Company's unaudited interim consolidated financial statements.

At December 31, 2006, the Company's working capital deficit was $832 million and included the current portion of the stock-based compensation liability of $611 million and the current portion of the net mark-to-market asset for non-designated risk management financial derivative instruments of $88 million. The settlement 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 December 31, 2006.

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 December 31, 2006, such as Baobab, Primrose and West Espoir, and the acquisition of ACC, are anticipated to provide identified growth in production volumes in 2007 through 2009, and generate incremental free cash flows during this period.

Primarily due to the additional debt issued to complete the ACC acquisition, long-term debt increased to $11,043 million at December 31, 2006, resulting in a debt to book capitalization level of 50.8% as at December 31, 2006, (September 30, 2006 – 34.6%; December 31, 2005 - 28.7%). While this ratio is above the 35% to 45% range targeted by management, the Company remains committed to maintaining a strong balance sheet and flexible capital structure, and expects its debt to book capitalization ratio to be near the midpoint of the range in 2008. While 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. In the future, the Company may also consider the divestiture of non-strategic and non-core properties to gain additional balance sheet flexibility.

The Company's 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 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. 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 65% of expected crude oil volumes and approximately 75% of expected natural gas volumes have been hedged for 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for 2007 at a strike price of US$60.00 per barrel. The Company is extending its hedge program into 2008 whereby 150,000 bbl/d of crude oil volumes have been hedged (100,000 bbl/d of price collars with a US$60.00 floor and 50,000 bbl/d of put options with a US$55.00 strike price). In addition, 900,000 GJ/d of natural gas volumes have been hedged through the use of price collars for the first quarter of 2008 (400,000 GJ/d with a floor of $7.00 and 500,000 GJ/d with a floor of $7.50).

In addition to the strategic location of the assets that ACC brings to the Company, this acquisition allows the Company to further high grade its project inventory and focus capital expenditures in the current highly inflationary service market. As a result of the acquisition, the Company has 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 1 of the Horizon Project.

Long-term debt

The Company's long-term debt of $11,043 million at December 31, 2006 was comprised of drawings under its bank credit facilities and debt issuances under medium and long-term unsecured notes.

Bank credit facilities

As at December 31, 2006 the Company had in place unsecured bank credit facilities of $7,809 million, comprised of:

- a $100 million demand credit facility;
- a $500 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $3,850 million;
- a 5-year revolving syndicated credit facility of $1,825 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter, the revolving syndicated credit 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 executed 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.

During the fourth quarter, the Company obtained a $500 million credit facility repayable on demand.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $338 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2006.

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.

Subsequent to December 31, 2006, the 7.40% unsecured debentures due March 1, 2007 were repaid.

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, respectively. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In November 2006, the shelf prospectus, filed in June 2005, was increased from US$2 billion to US$3 billion, leaving US$2.3 billion available for issue 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 December 31, 2006, there were 537,903,000 common shares outstanding and 34,425,000 stock options outstanding. As at March 3, 2007, the Company had 538,913,000 common shares outstanding and 31,565,000 stock options outstanding.

During 2006, the Company purchased 485,000 common shares for cancellation (2005 – 850,000 common shares) at an average price of $57.33 per common share (2005 – $53.29 per common share), for a total cost of $28 million (2005 – $45 million) pursuant to the Normal Course Issuer Bids previously filed.

In January 2007, the Company renewed 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, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at March 3, 2007, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

In February 2006, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.30 per common share for 2006. The increase represents a 27% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders.

In March 2007, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.34 per common share for 2007. The increase represents a 13% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the seventh consecutive year in which the Company has paid dividends and the sixth consecutive year of an increase in the distribution paid to its Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Commitments and off balance sheet arrangements

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to debt repayments, operating leases relating to office space and offshore FPSOs and drilling rigs, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. As at December 31, 2006, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2006:

($ millions)	2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline (1)	$ 213	$ 193	$ 134	$ 123	$ 99	$ 1,042
Offshore equipment operating lease (2)	$ 77	$ 52	$ 52	$ 52	$ 50	$ 131
Offshore drilling	$ 73	$ 83	$ 12	$ 12	$ 4	$ 4
Asset retirement obligations (3)	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4,480
Long-term debt (4)	$ 161	$ 45	$ 3,876	$ -	$ 466	$ 3,713
Office lease	$ 26	$ 32	$ 33	$ 34	$ 22	$ -
Electricity and other	$ 51	$ 10	$ 17	$ 18	$ 1	$ -

(1) *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) *Offshore equipment operating leases are primarily comprised of obligations related to FPSOs. During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million.*

(3) *Amounts represent 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. Amounts disclosed for the period 2007 – 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.*

(4) *The long-term debt represents principal repayments only. No debt repayments are reflected for $2,782 million of revolving bank credit facilities due to the extendable nature of the facilities.*

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

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.

SENSITIVITY ANALYSIS [1]

The following table is indicative 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 sales volumes during the fourth quarter of 2006, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change 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	$	116	$	0.22	$	81	$	0.15
Including financial derivatives	$	26-110	$	0.05-0.21	$	20-77	$	0.04-0.14
Natural gas – AECO C$0.10/mcf [2]								
Excluding financial derivatives	$	26	$	0.05	$	14	$	0.03
Including financial derivatives	$	1-8	$	0.00-0.02	$	2-4	$	0.00-0.01
Volume changes								
Crude oil – 10,000 bbl/d	$	98	$	0.18	$	44	$	0.08
Natural gas – 10 mmcf/d	$	17	$	0.03	$	6	$	0.01
Foreign currency rate change								
$0.01 change in C$ in relation to US$ [2]								
Excluding financial derivatives	$	80-82	$	0.15	$	23-24	$	0.04
Interest rate change - 1%	$	48	$	0.09	$	48	$	0.09

(1) The sensitivities are calculated based on 2006 fourth quarter results and exclude mark-to-market gains (losses) on risk management activities.

(2) For details of outstanding financial instruments in place, refer to note 10 of the Company's unaudited interim consolidated financial statements.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

($/boe) [1]	Three Months Ended Dec 31 2006	Sep 30 2006	Dec 31 2005	Year Ended Dec 31 2006	Dec 31 2005
Sales price [2]	**$ 43.91**	$ 51.21	$ 56.08	**$ 47.92**	$ 48.77
Royalties	**5.62**	5.75	8.01	**5.89**	6.82
Production expense [3]	**9.16**	10.01	7.93	**9.14**	8.21
Netback	**29.13**	35.45	40.14	**32.89**	33.74
Midstream contribution [3]	**(0.22)**	(0.23)	(0.25)	**(0.23)**	(0.26)
Administration	**1.01**	0.76	0.68	**0.85**	0.75
Interest, net	**1.08**	0.48	0.53	**0.66**	0.74
Realized risk management loss	**2.25**	7.51	9.07	**6.27**	5.13
Realized foreign exchange (gain) loss	**(0.34)**	0.01	(0.29)	**(0.06)**	(0.15)
Taxes other than income tax - current	**0.78**	1.50	0.93	**1.04**	1.01
Current income tax - North America	**0.91**	0.97	0.17	**0.68**	0.50
Current income tax - North Sea	**0.54**	-	0.59	**0.14**	0.77
Current income tax - Offshore West Africa	**0.24**	0.11	0.35	**0.23**	0.17
Cash flow	**$ 22.88**	$ 24.34	$ 28.36	**$ 23.31**	$ 25.08

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

(2) Net of transportation and blending costs and excluding risk management activities.

(3) Excluding intersegment elimination.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	**Dec 31 2006**	Dec 31 2005
ASSETS		
Current assets		
Cash and cash equivalents	**$ 23**	$ 18
Accounts receivable and other	**1,947**	1,546
Future income tax	**163**	487
Current portion of other long-term assets (note 3)	**106**	-
	2,239	2,051
Property, plant and equipment (note 12)	**30,767**	19,694
Other long-term assets (note 3)	**154**	107
	$ 33,160	$ 21,852
LIABILITIES		
Current liabilities		
Accounts payable	**$ 842**	$ 573
Accrued liabilities	**1,618**	1,781
Current portion of other long-term liabilities (note 5)	**611**	1,471
	3,071	3,825
Long-term debt (note 4)	**11,043**	3,321
Other long-term liabilities (note 5)	**1,393**	1,434
Future income tax	**6,963**	5,035
	22,470	13,615
SHAREHOLDERS' EQUITY		
Share capital (note 8)	**2,562**	2,442
Retained earnings	**8,141**	5,804
Foreign currency translation adjustment	**(13)**	(9)
	10,690	8,237
	$ 33,160	$ 21,852

Commitments (note 11)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Dec 31 2006	Three Months Ended Dec 31 2005	Year Ended Dec 31 2006	Year Ended Dec 31 2005
Revenue	**$ 2,826**	$ 3,319	**$ 11,643**	$ 11,130
Less: royalties	**(317)**	(421)	**(1,245)**	(1,366)
Revenue, net of royalties	**2,509**	2,898	**10,398**	9,764
Expenses				
Production	**519**	423	**1,949**	1,663
Transportation and blending	**333**	353	**1,443**	1,293
Depletion, depreciation and amortization	**724**	550	**2,391**	2,013
Asset retirement obligation accretion (note 5)	**18**	16	**68**	69
Administration	**57**	36	**180**	151
Stock-based compensation (note 5)	**176**	125	**139**	723
Interest, net	**62**	28	**140**	149
Risk management activities (note 10)	**(115)**	(349)	**312**	1,952
Foreign exchange loss (gain)	**151**	(11)	**122**	(132)
	1,925	1,171	**6,744**	7,881
Earnings before taxes	**584**	1,727	**3,654**	1,883
Taxes other than income tax	**41**	51	**256**	194
Current income tax (note 7)	**95**	58	**222**	286
Future income tax (note 7)	**135**	514	**652**	353
Net earnings	**$ 313**	$ 1,104	**$ 2,524**	$ 1,050
Net earnings per common share (note 9)				
Basic	**$ 0.58**	$ 2.06	**$ 4.70**	$ 1.96
Diluted	**$ 0.58**	$ 2.06	**$ 4.70**	$ 1.95

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Year Ended Dec 31 2006	Year Ended Dec 31 2005
Balance – beginning of year	**$ 5,804**	$ 4,922
Net earnings	**2,524**	1,050
Dividends on common shares (note 8)	**(161)**	(127)
Purchase of common shares under Normal Course Issuer Bid (note 8)	**(26)**	(41)
Balance – end of year	**$ 8,141**	$ 5,804

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2006	Three Months Ended Dec 31 2005	Year Ended Dec 31 2006	Year Ended Dec 31 2005
Operating activities				
Net earnings	**$ 313**	$ 1,104	**$ 2,524**	$ 1,050
Non-cash items				
Depletion, depreciation and amortization	**724**	550	**2,391**	2,013
Asset retirement obligation accretion	**18**	16	**68**	69
Stock-based compensation	**176**	125	**139**	723
Unrealized risk management activities	**(241)**	(825)	**(1,013)**	925
Unrealized foreign exchange loss (gain)	**171**	5	**134**	(103)
Deferred petroleum revenue tax (recovery) expense	**(3)**	1	**37**	(9)
Future income tax	**135**	514	**652**	353
Deferred charges	**6**	2	**(2)**	(31)
Abandonment expenditures	**(19)**	(16)	**(75)**	(46)
Net change in non-cash working capital	**(317)**	(68)	**(679)**	(147)
	963	1,408	**4,176**	4,797
Financing activities				
Issue (repayment) of bank credit facilities	**5,384**	74	**6,499**	(435)
Issue of medium-term notes	**-**	-	**400**	400
Repayment of senior unsecured notes	**-**	(194)	**-**	(194)
Issue of US dollar debt securities	**-**	-	**788**	-
Repayment of preferred securities	**-**	-	**-**	(107)
Issue of common shares on exercise of stock options	**4**	3	**21**	9
Dividends on common shares	**(40)**	(32)	**(153)**	(121)
Purchase of common shares	**-**	(29)	**(28)**	(45)
Net change in non-cash working capital	**29**	3	**37**	19
	5,377	(175)	**7,564**	(474)
Investing activities				
Expenditures on property, plant and equipment	**(1,791)**	(1,764)	**(7,266)**	(5,340)
Net proceeds on sale of property, plant and equipment	**68**	101	**71**	454
Net expenditures on property, plant and equipment	**(1,723)**	(1,663)	**(7,195)**	(4,886)
Acquisition of Anadarko Canada Corporation (note 2)	**(4,641)**	-	**(4,641)**	-
Net proceeds on sale of other assets	**-**	-	**-**	11
Net change in non-cash working capital	**35**	436	**101**	542
	(6,329)	(1,227)	**(11,735)**	(4,333)
Increase (decrease) in cash and cash equivalents	**11**	6	**5**	(10)
Cash and cash equivalents – beginning of period	**12**	12	**18**	28
Cash and cash equivalents – end of period	**$ 23**	$ 18	**$ 23**	$ 18
Interest paid	**$ 83**	$ 48	**$ 262**	$ 200
Taxes paid				
Taxes other than income tax	**$ 52**	$ 21	**$ 291**	$ 192
Current income tax	**$ 108**	$ 46	**$ 412**	$ 238

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.

Comparative figures

Certain figures relating to the presentation of gross revenues and gross transportation and blending provided for the prior year have been reclassified to conform to the presentation adopted in 2006.

2. ACQUISITION OF ANADARKO CANADA CORPORATION

In November 2006, the Company completed the acquisition of all of the issued and outstanding common shares of Anadarko Canada Corporation ("ACC"), a subsidiary of Anadarko Petroleum Corporation, for net cash consideration of $4,641 million including working capital and other adjustments. Substantially all of ACC's land and production base are located in Western Canada.

The acquisition was accounted for using the purchase method. Operating results from ACC have been consolidated with the results of the Company effective from November 2, 2006, the date of acquisition, and are reported in the North America segment. The preliminary allocation of the net purchase price is subject to change as actual amounts are determined. The preliminary allocation of the net purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

Net purchase price:	
Net cash consideration[1]	$ **4,641**
Net purchase price allocated as follows:	
Non-cash working capital deficit assumed and other	$ **(105)**
Property, plant and equipment	**6,249**
Long-term debt	**(9)**
Asset retirement obligation	**(56)**
Future income tax	**(1,438)**
	$ **4,641**

(1) Net cash consideration was reduced by $88 million to reflect the settlement of US dollar currency forward contracts designated as hedges of the ACC share purchase price.

3. OTHER LONG–TERM ASSETS

	Dec 31 2006	Dec 31 2005
Deferred charges	**$ 109**	$ 107
Risk management (note 10)	**128**	-
Other	**23**	-
	260	107
Less: current portion	**106**	-
	$ 154	$ 107

4. LONG–TERM DEBT

	Dec 31 2006	Dec 31 2005
Bank credit facilities		
Bankers' acceptances	**$ 6,621**	$ 122
Medium-term notes	**925**	525
Senior unsecured notes (2006 and 2005 - US$93 million)	**108**	108
US dollar debt securities (2006 - US$2,908; and 2005 - US$2,200 million)	**3,389**	2,566
	$ 11,043	$ 3,321

Bank credit facilities

As at December 31, 2006, the Company had in place unsecured bank credit facilities of $7,809 million, comprised of:

- a $100 million demand credit facility;
- a $500 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $3,850 million;
- a 5-year revolving syndicated credit facility of $1,825 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter, the revolving syndicated credit 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 (note 2), the Company executed 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.

During the fourth quarter, the Company obtained a $500 million credit facility repayable on demand.

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

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $338 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2006.

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.

Subsequent to December 31, 2006, the 7.40% unsecured debentures due March 1, 2007 were repaid.

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 10). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In November 2006, the shelf prospectus, filed in June 2005, was increased from US$2 billion to US$3 billion, leaving US$2.3 billion available for issue in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

5. OTHER LONG–TERM LIABILITIES

	Dec 31 2006	Dec 31 2005
Asset retirement obligations	**$ 1,166**	$ 1,112
Stock-based compensation	**744**	891
Risk management (note 10)	**-**	885
Other	**94**	17
	2,004	2,905
Less: current portion	**611**	1,471
	$ 1,393	$ 1,434

Asset retirement obligations

At December 31, 2006, the Company's total estimated undiscounted cost to settle its asset retirement obligations was approximately $4,497 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 6.7%. A reconciliation of the discounted asset retirement obligations is as follows:

	Year Ended Dec 31, 2006	Year Ended Dec 31, 2005
Balance – beginning of year	**$ 1,112**	$ 1,119
Liabilities incurred	**26**	47
Liabilities acquired (note 2)	**56**	-
Liabilities settled	**(75)**	(46)
Asset retirement obligation accretion	**68**	69
Revision of estimates	**(21)**	(56)
Foreign exchange	**-**	(21)
Balance – end of year	**$ 1,166**	$ 1,112

The Company's pipelines have indeterminate 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.

	Year Ended Dec 31, 2006	Year Ended Dec 31, 2005
Balance – beginning of year	**$ 891**	$ 323
Stock-based compensation	**139**	723
Current year payment for options surrendered	**(264)**	(227)
Transferred to common shares	**(101)**	(29)
Capitalized to Horizon Project	**79**	101
Balance – end of year	**744**	891
Less: current portion of stock-based compensation	**611**	629
	$ 133	$ 262

6. EMPLOYEE FUTURE BENEFITS

In connection with the acquisition of ACC, the Company assumed obligations to provide defined contribution pension benefits to certain ACC employees continuing their employment with the Company, and defined benefit pension and other post-retirement benefits to former ACC employees, under registered and unregistered pension plans.

The estimated future cost of providing defined benefit pension and other post-retirement benefits to former ACC employees is actuarially determined using management's best estimates of demographic and financial assumptions. The discount rate of 5% used to determine accrued benefit obligations is based on a year end market rate of interest for high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Company contributions to the defined contribution plan are expensed as incurred.

The benefit obligation under the registered pension plan at December 31, 2006 was $29 million. As required by government regulations, the Company has set aside funds with an independent trustee to meet these benefit obligations. As at December 31, 2006, these plan assets had a fair value of $54 million. The unregistered pension plans are unfunded and have a benefit obligation of $15 million at December 31, 2006.

7. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Current income tax – North America	**$ 51**	$ 8	**$ 143**	$ 99
Current income tax – North Sea	**30**	31	**30**	155
Current income tax – Offshore West Africa	**14**	19	**49**	32
Current income tax	**95**	58	**222**	286
Future income tax	**135**	514	**652**	353
Income tax expense	**$ 230**	$ 572	**$ 874**	$ 639

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 future period. 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 in any particular year.

During 2006, income tax rate changes resulted in a reduction of future income tax liabilities of approximately $438 million in North America, an increase of future income tax liabilities of approximately $110 million in the UK North Sea and a reduction of future income tax liabilities of approximately $67 million in Côte d'Ivoire.

8. SHARE CAPITAL

	Year Ended Dec 31, 2006	
Issued **Common shares**	**Number of shares** (thousands)	**Amount**
Balance – beginning of year	**536,348**	**$ 2,442**
Issued upon exercise of stock options	**2,040**	**21**
Previously recognized liability on stock options exercised for common shares	**-**	**101**
Purchase of common shares under Normal Course Issuer Bid	**(485)**	**(2)**
Balance – end of year	**537,903**	**$ 2,562**

Normal Course Issuer Bid

During 2006, the Company purchased 485,000 common shares for cancellation 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 average carrying value.

In January 2007, the Company renewed 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, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at March 3, 2007, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

Dividend policy

In March 2007, the Board of Directors set the regular quarterly dividend at $0.085 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.

In February 2006, the Board of Directors set the regular quarterly dividend at $0.075 per common share (2005 - $0.059 per common share).

Stock options

	Year Ended Dec 31, 2006	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of year	**30,510**	**$ 17.79**
Granted	**13,084**	**$ 59.61**
Exercised for common shares	**(2,040)**	**$ 10.67**
Surrendered for cash settlement	**(5,180)**	**$ 12.60**
Forfeited	**(1,949)**	**$ 37.51**
Outstanding – end of year	**34,425**	**$ 33.77**
Exercisable – end of year	**9,177**	**$ 14.73**

9. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Weighted average common shares outstanding (thousands)				
Basic	**537,616**	536,482	**537,339**	536,650
Assumed settlement of preferred securities with common shares(1)	**-**	-	**-**	1,775
Diluted	**537,616**	536,482	**537,339**	538,425
Net earnings	**$ 313**	$ 1,104	**$ 2,524**	$ 1,050
Interest on preferred securities, net of tax(1)	**-**	-	**-**	4
Revaluation on preferred securities, net of tax(1)	**-**	-	**-**	(2)
Diluted net earnings	**$ 313**	$ 1,104	**$ 2,524**	$ 1,052
Net earnings per common share				
Basic	**$ 0.58**	$ 2.06	**$ 4.70**	$ 1.96
Diluted	**$ 0.58**	$ 2.06	**$ 4.70**	$ 1.95

(1) The preferred securities were redeemed in September 2005.

10. 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 intended for trading or other speculative purposes.

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

	Year Ended Dec 31, 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 year	**$ (877)**	**$ (8)**	$ 66	$ (26)
Net cost of outstanding put options	**455**	**-**	190	-
Net change in fair value of outstanding derivative financial instruments	**1,005**	**-**	(943)	-
Amortization of deferred revenue	**-**	**8**	-	18
	583	**-**	(687)	(8)
Add: Put premium financing obligations(1)	**(455)**	**-**	(190)	-
Balance – end of year	**128**	**-**	(877)	(8)
Less: current portion	**88**	**-**	(834)	(8)
	$ 40	**$ -**	$ (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 net risk management asset (liability).

Net losses (gains) from risk management activities for the periods ended December 31 were as follows:

	Three Months Ended		Year Ended	
	Dec 31 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Net realized risk management loss	**$ 126**	$ 476	**$ 1,325**	$ 1,027
Net unrealized risk management mark-to-market (gain) loss	**(241)**	(825)	**(1,013)**	925
	$ (115)	$ (349)	**$ 312**	$ 1,952

As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million (December 31, 2005 – net unrecognized liability of $990 million).

The Company had the following net financial derivatives outstanding as at December 31, 2006:

	Remaining term			Volume	Average price			Index
Crude oil								
Price collars	Jan 2007	–	Dec 2007	15,000 bbl/d	US$50.00	–	US$66.25	Mayan Heavy
	Jan 2007	–	Dec 2007	50,000 bbl/d	US$60.00	–	US$71.49	WTI
	Jan 2007	–	Dec 2007	100,000 bbl/d	US$60.00	–	US$78.11	WTI
	Jan 2007	–	Dec 2007	50,000 bbl/d	US$65.00	–	US$84.52	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
Put options(1)	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	Jan 2007	–	Dec 2007	50,000 bbl/d			US$1.34	WTI/Dated Brent

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

	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Cost(1) ($ millions)	US$82	US$83	US$83	US$83	US$14	US$15	US$15	US$15

(1) Subsequent to December 31, 2006, the Company unwound 23,000 bbl/d of US$60.00 WTI put options for the period February 2007 to December 2007, for cash consideration of US$40 million.

	Remaining term			Volume	Average price			Index
Natural gas								
AECO collars	Jan 2007	–	Mar 2007	100,000 GJ/d	C$7.00	–	C$11.63	AECO
	Jan 2007	–	Mar 2007	200,000 GJ/d	C$7.25	–	C$8.38	AECO
	Jan 2007	–	Mar 2007	162,500 GJ/d	C$7.25	–	C$9.48	AECO
	Jan 2007	–	Mar 2007	162,500 GJ/d	C$7.50	–	C$8.94	AECO
	Jan 2007	–	Mar 2007	300,000 GJ/d	C$7.50	–	C$18.77	AECO
	Jan 2007	–	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	400,000 GJ/d	C$7.00	–	C$14.08	AECO
	Nov 2007	–	Mar 2008	500,000 GJ/d	C$7.50	–	C$10.81	AECO

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

In addition to the financial derivatives noted above, the Company 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 and 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	Jan 2007	–	Oct 2012	US$350	5.45%	LIBOR[1] + 0.81%
	Jan 2007	–	Dec 2014	US$350	4.90%	LIBOR[1] + 0.38%
Swaps – floating to fixed	Jan 2007	–	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	Jan 2007	–	Aug 2016	US$250	1.116	6.00%	5.40%

11. COMMITMENTS

The Company has committed to certain payments as follows:

		2007		2008		2009		2010		2011		Thereafter
Product transportation and pipeline[1]	$	213	$	193	$	134	$	123	$	99	$	1,042
Offshore equipment operating lease[2]	$	77	$	52	$	52	$	52	$	50	$	131
Offshore drilling	$	73	$	83	$	12	$	12	$	4	$	4
Asset retirement obligations[3]	$	3	$	3	$	3	$	4	$	4	$	4,480
Office lease	$	26	$	32	$	33	$	34	$	22	$	-
Electricity and other	$	51	$	10	$	17	$	18	$	1	$	-

(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) Offshore equipment operating leases are primarily comprised of obligations related to floating production, storage and offtake vessels ("FPSO"). During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million.

(3) Amounts represent 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. Amounts disclosed for the period 2007 – 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

12. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America Three Months Ended Dec 31		North America Year Ended Dec 31		North Sea Three Months Ended Dec 31		North Sea Year Ended Dec 31		Offshore West Africa Three Months Ended Dec 31		Offshore West Africa Year Ended Dec 31	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Segmented revenue	**2,243**	2,663	**9,066**	8,955	**352**	371	**1,616**	1,659	**232**	280	**950**	485
Less: royalties	**(305)**	(413)	**(1,203)**	(1,350)	**(1)**	(1)	**(3)**	(3)	**(11)**	(7)	**(39)**	(13)
Segmented revenue, net of royalties	**1,938**	2,250	**7,863**	7,605	**351**	370	**1,613**	1,656	**221**	273	**911**	472
Segmented expenses												
Production	**400**	322	**1,436**	1,211	**77**	68	**390**	379	**38**	26	**106**	53
Transportation and blending	**337**	359	**1,465**	1,310	**4**	4	**15**	20	**1**	-	**1**	-
Depletion, depreciation and amortization	**580**	412	**1,897**	1,595	**85**	70	**297**	306	**57**	66	**189**	104
Asset retirement obligation accretion	**9**	9	**35**	34	**9**	6	**31**	34	**-**	1	**2**	1
Realized risk management activities	**76**	432	**1,022**	870	**50**	44	**303**	157	**-**	-	**-**	-
Total segmented expenses	**1,402**	1,534	**5,855**	5,020	**225**	192	**1,036**	896	**96**	93	**298**	158
Segmented earnings (loss) before the following	**536**	716	**2,008**	2,585	**126**	178	**577**	760	**125**	180	**613**	314
Non-segmented expenses												
Administration												
Stock-based compensation												
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												
Net earnings												

(millions of Canadian dollars, unaudited)	Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Segmented revenue	**18**	21	**72**	77	**(19)**	(16)	**(61)**	(46)	**2,826**	3,319	**11,643**	11,130
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-	**(317)**	(421)	**(1,245)**	(1,366)
Segmented revenue, net of royalties	**18**	21	**72**	77	**(19)**	(16)	**(61)**	(46)	**2,509**	2,898	**10,398**	9,764
Segmented expenses												
Production	**6**	8	**23**	24	**(2)**	(1)	**(6)**	(4)	**519**	423	**1,949**	1,663
Transportation and blending	**-**	-	**-**	-	**(9)**	(10)	**(38)**	(37)	**333**	353	**1,443**	1,293
Depletion, depreciation and amortization	**2**	2	**8**	8	**-**	-	**-**	-	**724**	550	**2,391**	2,013
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**18**	16	**68**	69
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**126**	476	**1,325**	1,027
Total segmented expenses	**8**	10	**31**	32	**(11)**	(11)	**(44)**	(41)	**1,720**	1,818	**7,176**	6,065
Segmented earnings (loss) before the following	**10**	11	**41**	45	**(8)**	(5)	**(17)**	(5)	**789**	1,080	**3,222**	3,699
Non-segmented expenses												
Administration									**57**	36	**180**	151
Stock-based compensation									**176**	125	**139**	723
Interest, net									**62**	28	**140**	149
Unrealized risk management activities									**(241)**	(825)	**(1,013)**	925
Foreign exchange loss (gain)									**151**	(11)	**122**	(132)
Total non-segmented expenses									**205**	(647)	**(432)**	1,816
Earnings before taxes									**584**	1,727	**3,654**	1,883
Taxes other than income tax									**41**	51	**256**	194
Current income tax expense									**95**	58	**222**	286
Future income tax expense									**135**	514	**652**	353
Net earnings									**313**	1,104	**2,524**	1,050

Net additions to property, plant and equipment

	Year Ended					
	Dec 31, 2006			Dec 31, 2005		
	Cash Expenditures	**Non-Cash/ Fair Value Changes[1]**	**Capitalized Costs**	Cash Expenditures	Non-Cash/ Fair Value Changes[1]	Capitalized Costs
North America	**$ 7,936**	**$ 1,521**	**$ 9,457**	$ 2,530	$ (22)	$ 2,508
North Sea	**646**	**(14)**	**632**	387	(136)	251
Offshore West Africa	**134**	**1**	**135**	439	27	466
Other	**11**	**-**	**11**	5	-	5
Horizon Project[2]	**3,185**	**-**	**3,185**	1,499	-	1,499
Midstream	**12**	**-**	**12**	4	-	4
Head office	**26**	**-**	**26**	22	-	22
	$ 11,950	**$ 1,508**	**$ 13,458**	$ 4,886	$ (131)	$ 4,755

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

(2) Cash expenditures for the Horizon Project also include capitalized interest and stock-based compensation.

	Property, plant and equipment		Total assets	
	Dec 31 2006	Dec 31 2005	**Dec 31 2006**	Dec 31 2005
Segmented assets				
North America	**$ 21,879**	$ 14,310	**$ 23,670**	$ 15,939
North Sea	**2,029**	1,681	**2,248**	1,950
Offshore West Africa	**1,204**	1,253	**1,323**	1,371
Other	**24**	13	**46**	30
Horizon Project	**5,350**	2,169	**5,444**	2,239
Midstream	**207**	203	**355**	258
Head office	**74**	65	**74**	65
	$ 30,767	$ 19,694	**$ 33,160**	$ 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 on Phase 1 will cease once construction is substantially complete and this phase of the Horizon Project is available for its intended use. For the year ended December 31, 2006, pre-tax interest of $196 million was capitalized to the Horizon Project (December 31, 2005 - $72 million).

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 December 31, 2006:

Interest coverage (times)	
Net earnings(1)	10.5x
Cash flow from operations(2)	15.8x

(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.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Wednesday, March 7, 2007. The North American conference call number is 1-800-769-8320 and the outside North American conference call number is 001-416-695-6130. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time Wednesday, March 14, 2007. To access the postview in North America, dial 1-888-509-0081. Those outside of North America, dial 001-416-695-5275. The passcode to use is 638222.

WEBCAST

This call is being webcast by Vcall and can be accessed on Canadian Natural's website at www.cnrl.com/investor_info/calendar.html.

The webcast is also being distributed over PrecisionIR's Investor Distribution Network to both institutional and individual investors. Investors can listen to the call through www.vcall.com or by visiting any of the investor sites in PrecisionIR's Individual Investor Network.

2007 FIRST QUARTER RESULTS

2007 first quarter results are scheduled for release on Thursday, May 3, 2007. A conference call will be held on that day at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time.

ANNUAL AND SPECIAL MEETING OF THE SHAREHOLDERS

Canadian Natural Resources Limited's Annual and Special Meeting of the Shareholders will be held on Thursday, May 3, 2007 at 3:00 p.m. Mountain Time at the Metropolitan Centre, Calgary, Alberta. All shareholders are invited to attend.

For further information, please contact:

CANADIAN NATURAL RESOURCES LIMITED

2500, 855 - 2nd Street S.W.

Calgary, Alberta

T2P 4J8

Telephone: (403) 514-7777
Facsimile: (403) 514-7888
Email: ir@cnrl.com
Website: www.cnrl.com

Trading Symbol - CNQ
Toronto Stock Exchange
New York Stock Exchange

ALLAN P. MARKIN
Chairman

JOHN G. LANGILLE
Vice-Chairman

STEVE W. LAUT
President &
Chief Operating Officer

DOUGLAS A. PROLL
Chief Financial Officer &
Senior Vice-President, Finance

COREY B. BIEBER
Vice-President,
Finance & Investor Relations