Canadian Natural

PRESS RELEASE

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2011 THIRD QUARTER RESULTS AND 2012 BUDGET

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Commenting on third quarter results, Canadian Natural's Chairman, Allan Markin stated, "Our experienced team produced excellent operating and financial results across all operating areas in Q3/11. Production successfully recommenced at Horizon and our North America E&P operations achieved record production at both our primary heavy oil and thermal in situ operations.

The Company delivered on its commitment to safely restore full production at Horizon in Q3/11. Operations recommenced on August 16, 2011 and production ramped up in September to average approximately 108,200 bbl/d of SCO. With turnaround and opportune maintenance complete and a portion of the 2012 turnaround deferred to 2013, we look forward in 2012 to solid production and cash flow generation from Horizon."

John Langille, Vice-Chairman of Canadian Natural continued, "We have significant capital flexibility in the 2012 capital program allowing us to quickly adapt our capital spending profile to changing market conditions. Cash flow generation in 2012 will enable us to execute the capital program, capitalize on value adding opportunistic acquisitions, pre-invest in long term projects, and manage our dividends and debt levels."

Steve Laut, President of Canadian Natural stated, "In 2012 we are targeting 24% crude oil and NGL production growth, 17% overall BOE production growth and 10% production growth Q4/11 to Q4/12, reflective of a strong primary heavy oil drilling program, continued pad development at Primrose, Canadian light oil and NGL growth and solid production from Horizon. The Company will continue to focus on developing its top quality Oil Sands assets as we continue to transform the Company into a longer life, sustainable asset base capable of generating significant economic returns for years well beyond 2012."

QUARTERLY HIGHLIGHTS

($ millions, except as noted)	Three Months Ended Sep 30 2011	Jun 30 2011	Sep 30 2010	Nine Months Ended Sep 30 2011	Sep 30 2010
Net earnings	**$ 836**	$ 929	$ 596	**$ 1,811**	$ 1,982
Per common share - basic	**$ 0.76**	$ 0.85	$ 0.54	**$ 1.65**	$ 1.82
- diluted	**$ 0.76**	$ 0.84	$ 0.54	**$ 1.64**	$ 1.81
Adjusted net earnings from operations (1)	**$ 719**	$ 621	$ 573	**$ 1,568**	$ 1,859
Per common share - basic	**$ 0.65**	$ 0.57	$ 0.53	**$ 1.43**	$ 1.71
- diluted	**$ 0.65**	$ 0.56	$ 0.52	**$ 1.42**	$ 1.70
Cash flow from operations (2)	**$ 1,767**	$ 1,548	$ 1,545	**$ 4,389**	$ 4,681
Per common share - basic	**$ 1.62**	$ 1.41	$ 1.41	**$ 4.01**	$ 4.30
- diluted	**$ 1.60**	$ 1.40	$ 1.41	**$ 3.98**	$ 4.27
Capital expenditures, net of dispositions	**$ 1,406**	$ 1,405	$ 917	**$ 4,505**	$ 3,569
Daily production, before royalties					
Natural gas (MMcf/d)	**1,252**	1,240	1,258	**1,249**	1,240
Crude oil and NGLs (bbl/d)	**403,900**	349,915	411,585	**370,439**	420,319
Equivalent production (BOE/d)	**612,575**	556,539	621,284	**578,618**	627,052

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

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

- Production in Q3/11 in all areas met or exceeded previously issued guidance as a result of efficient and effective operations. Thermal in situ ("bitumen") and primary heavy crude oil had record quarterly production contributing to strong North America E&P crude oil production. Continued success at Septimus together with production from properties acquired in 2011 resulted in North America natural gas production slightly above previously issued guidance.

- Total crude oil and NGLs production for Q3/11 was 403,900 bbl/d. Q3/11 crude oil production volumes decreased 2% from Q3/10 levels of 411,585 bbl/d and increased by 15% from Q2/11 level of 349,915 bbl/d. The increase from the previous quarter was primarily due to the recommencement of production at Horizon, the impact of a record primary heavy oil drilling program and excellent thermal in situ performance. The decrease from Q3/10 was primarily related to the suspension of production at Horizon for the first half of Q3/11.

- Crude oil and NGLs production from North America E&P operations in Q3/11 was 304,671 bbl/d. Q3/11 crude oil and NGLs production volumes increased 14% from Q3/10 levels of 267,177 bbl/d, and increased 3% from Q2/11 levels of 295,715 bbl/d. The increase in production from Q3/10 and Q2/11 was primarily due to the impact of a record heavy oil drilling program, new pad additions at Primrose and the cyclic nature of the Company's thermal in situ operations.

- Natural gas production from North America operations in Q3/11 was above the Company's previously issued guidance of 1,205 MMcf/d to 1,225 MMcf/d. North America natural gas production decreased 1% to 1,226 MMcf/d for Q3/11 compared to 1,234 MMcf/d in Q3/10 and increased 1% compared to 1,218 MMcf/d in Q2/11. Natural gas production reflects continued strong production volumes from Septimus in NE British Columbia, the impact of natural gas producing properties acquired during 2011 and the impact of the strategic reduction of natural gas drilling activity.

- Quarterly cash flow from operations was $1.77 billion compared to $1.55 billion for Q3/10 and $1.55 billion for Q2/11. The increase in cash flow from Q3/10 was primarily related to higher North America crude oil and NGL sales volumes and higher crude oil and NGL netbacks, partially offset by the impact of lower production at Horizon. The increase in cash flow from Q2/11 was primarily a result of the recommencement of production at Horizon.

- Adjusted net earnings from operations for Q3/11 was $719 million, compared to adjusted net earnings of $573 million in Q3/10 and $621 million in Q2/11. Changes in adjusted net earnings reflect the changes in cash flow from operations.
- Primary heavy crude oil operations achieved record quarterly production for the third consecutive quarter. Production exceeded 101,500 bbl/d in Q3/11 as part of the targeted record drilling program in 2011. As at Q3/11 the Company has drilled 565 net primary heavy crude oil wells which will contribute to a targeted 10% annual production growth in primary heavy crude oil. Primary heavy crude oil continues to provide the highest return on capital projects in the Company's portfolio.
- Thermal in situ crude oil achieved record quarterly production of approximately 110,000 bbl/d in Q3/11 due to continued pad additions at Primrose, excellent overall performance in the quarter and the nature of the steaming and production cycles. Production in 2011 is targeted to average between 97,000 bbl/d and 98,000 bbl/d with the normal peaks and valleys inherent to cyclic steam stimulation.
- Construction at the Kirby South Phase 1 ("Kirby") Steam Assisted Gravity Drainage ("SAGD") project remains on cost and on schedule. Drilling has been completed on the first of seven pads and has commenced on the second pad. Completion of the second pad is targeted for Q4/11. Kirby has targeted capital costs of $1.25 billion and first steam-in is targeted for late 2013. Production is targeted to ramp to 40,000 bbl/d with facility capacity of 45,000 bbl/d providing the ability to optimize performance. The total project is 29% complete at the end of Q3/11.
- Regulatory approvals required to execute the 2012 expansion plans at Pelican Lake were received in the quarter.
- Synthetic crude oil ("SCO") production at the Horizon Oil Sands successfully and safely resumed on August 16, 2011. August average production was approximately 44,800 bbl/d, September averaged approximately 108,200 bbl/d and October averaged approximately 105,600 reflective of the coker furnace pigging completed in October 2011.
- Subsequent to Q3/11, commissioning of the third Ore Preparation Plant ("OPP") and associated hydro-transport began on time and on budget with completion targeted by the end of November 2011 followed by start-up. The third OPP will increase production reliability and result in higher plant uptime in 2012 at Horizon.
- The Company repurchased 3.071 million common shares year-to-date at an average cost of $33.68/share under the Company's Normal Course Issuer Bid.
- Subsequent to Q3/11 Standard and Poor's Financial Services LLC upgraded the Company's unsecured credit rating to BBB+ (Stable outlook) from BBB (Positive outlook).
- Declared a quarterly cash dividend on common shares of $0.09 per common share payable January 1, 2012.

HIGHLIGHTS OF THE 2012 BUDGET

- Targeted overall production growth of 17% based on production guidance of 675,000 – 726,000 BOE/d as part of a product mix encompassing approximately 70% crude oil and NGL and 30% natural gas. Total production growth from Q4/11 to Q4/12 is targeted at 10%.
- Crude oil and NGL production is targeted to increase 24% from 2011 levels reflecting the return of production at Horizon, primary heavy oil growth of 16%, thermal in situ growth of 10%, and North America light oil and NGL growth of 17%.
- North America natural gas production is targeted to grow 3% reflecting economic drilling activities at Septimus and certain other liquids rich plays in NE British Columbia and NW Alberta as well as acquisitions completed in 2011.
- Cash flow is targeted at $8.2 billion to $8.6 billion based on average annual WTI strip pricing of US$88.12/bbl and AECO strip pricing of C$3.45/GJ.
- Capital spending in 2012 is budgeted at $7.2 billion, including $3.8 billion of long-term project developments and $3.0 billion of flexible capital spending.
- Free cash flow (cash flow after capital expenditures excluding acquisitions) is targeted between $1.1 billion and $1.5 billion.

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. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal in situ, SCO and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Drilling activity (number of wells)

	Nine Months Ended Sep 30			
	2011		2010	
	Gross	**Net**	Gross	Net
Crude oil [1]	**816**	**773**	663	616
Natural gas	**68**	**56**	90	74
Dry	**32**	**31**	30	25
Subtotal	**916**	**860**	783	715
Stratigraphic test / service wells	**547**	**545**	321	320
Total	**1,463**	**1,405**	1,104	1,035
Success rate (excluding stratigraphic test / service wells)		**96%**		97%

(1) Including thermal in situ wells.

North America Exploration and Production

North America natural gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Natural gas production (MMcf/d)	**1,226**	1,218	1,234	**1,223**	1,216
Net wells targeting natural gas	**21**	10	19	**57**	79
Net successful wells drilled	**21**	10	19	**56**	74
Success rate	**100%**	100%	100%	**98%**	94%

- Natural gas production from North America operations in Q3/11 was above the Company's previously issued guidance of 1,205 MMcf/d to 1,225 MMcf/d. North America natural gas production decreased 1% to 1,226 MMcf/d for Q3/11 compared to 1,234 MMcf/d in Q3/10 and increased 1% compared to 1,218 MMcf/d in Q2/11. Natural gas production reflects continued strong production volumes from Septimus in NE British Columbia, the impact of natural gas producing properties acquired during 2011 and the impact of the strategic reduction of natural gas drilling activity.

- In Q3/11 the Company continued to focus on the development of its liquids rich unconventional natural gas plays in NE British Columbia and NW Alberta. These selected properties compete for capital against the company's robust oil projects.

- Planned drilling activity for Q4/11 includes 23 net natural gas wells, substantially targeting liquids rich plays.

North America crude oil and NGLs

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs production (bbl/d)	**304,671**	295,715	267,177	**296,892**	265,125
Net wells targeting crude oil	**327**	182	289	**802**	630
Net successful wells drilled	**317**	177	281	**773**	616
Success rate	**97%**	97%	97%	**96%**	98%

- Crude oil and NGLs production from North America E&P operations in Q3/11 was 304,671 bbl/d. Q3/11 crude oil and NGLs production volumes increased 14% from Q3/10 levels of 267,177 bbl/d, and increased 3% from Q2/11 levels of 295,715 bbl/d. The increase in production from Q3/10 and Q2/11 was primarily due to the impact of a record heavy oil drilling program, new pad additions at Primrose and the cyclic nature of the Company's thermal in situ operations.

- Primary heavy crude oil operations achieved record quarterly production for the third consecutive quarter. Production exceeded 101,500 bbl/d in Q3/11 as part of the targeted record drilling program in 2011. The Company has drilled 565 net primary heavy crude oil wells in 2011 which will contribute to a targeted 10% annual production growth in primary heavy crude oil. Primary heavy crude oil continues to provide the highest return on capital projects in the Company's portfolio.

- Regulatory approvals required to execute the 2012 expansion plans at Pelican Lake were received in the quarter. Development of Pelican Lake is continuing and polymer response is positive. Continued work to optimize capital efficiencies and monitor ongoing polymer response will result in the next phase of commercial development being delayed. This will facilitate the ability to capture opportunities to optimize well configuration and injection strategies.

- The Company's focus on its high quality thermal in situ crude oil assets resulted in record quarterly production in Q3/11 of approximately 110,000 bbl/d. Development of new low cost pads at Primrose continue on track and on budget. Construction at the Kirby SAGD project remains on cost and on schedule. Drilling has been completed on the first of seven pads and has commenced on the second pad. Completion of the second pad is targeted for Q4/11. Kirby has targeted capital costs of $1.25 billion and first steam-in is targeted for late 2013. Production is targeted to ramp to 40,000 bbl/d with facility capacity of 45,000 bbl/d providing the ability to optimize performance. The total project is 29% complete at the end of Q3/11.

- During Q3/11, 327 net crude oil wells were drilled.

- Planned drilling activity for Q4/11 includes 47 net thermal in situ wells and 321 net crude oil wells, excluding stratigraphic test and service wells.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil production (bbl/d)					
North Sea	**26,350**	32,866	27,045	**31,077**	33,828
Offshore Africa	**22,525**	21,334	33,554	**23,105**	31,126
Natural gas production (MMcf/d)					
North Sea	**5**	7	8	**7**	10
Offshore Africa	**21**	15	16	**19**	14
Net wells targeting crude oil	**0.0**	0.0	0.9	**0.9**	5.6
Net successful wells drilled	**0.0**	0.0	0.9	**0.9**	5.6
Success rate	**0%**	0%	100%	**100%**	100%

- North Sea crude oil production was 26,350 bbl/d during Q3/11. Crude oil production decreased 3% in Q3/11 from Q3/10 and 20% from Q2/11 due to scheduled turnarounds at the Ninian South and Tiffany platforms and natural field declines. The maintenance shutdowns were completed on time and on budget and the fields have returned to normal production.
- In March 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. This resulted in an increase to the overall corporate tax rate applicable to net operating income from oil and gas activities to 62% for non-PRT paying fields and 81% for PRT paying fields, after allowing for deductions for capital and abandonment expenditures. As a result, the Company’s development activities in the North Sea have been reduced. The Company will continue to high grade all North Sea prospects for potential future development opportunities.
- Production in Offshore Africa was 22,525 bbl/d in Q3/11 slightly exceeding the Company’s previously issued guidance of 19,000 bbl/d to 22,000 bbl/d primarily as a result of the early reinstatement of production at Olowi.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Synthetic crude oil production (bbl/d)	**50,354**	-	83,809	**19,365**	90,240

- SCO production at the Horizon Oil Sands successfully and safely resumed on August 16, 2011. August average production was approximately 44,800 bbl/d, September averaged approximately 108,200 bbl/d and October averaged approximately 105,600 bbl/d reflective of the coker furnace pigging completed in October.
- Turnaround and opportune maintenance have been completed. Portions of the turnaround originally scheduled for 2012 have been accelerated and remaining portions of that turnaround are now expected to be deferred to 2013.
- Subsequent to Q3/11 commissioning of the third OPP and associated hydro-transport began on time and on budget with completion targeted by the end of November 2011 followed by start-up. The third OPP will increase production reliability and result in higher plant uptime in 2012 at Horizon.
- Horizon expansion activities continue to progress on track and are at or below cost estimates.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs pricing					
WTI[1] benchmark price (US$/bbl)	**$ 89.81**	$ 102.55	$ 76.21	**$ 95.52**	$ 77.65
Western Canadian Select blend differential from WTI (%)	**20%**	17%	20%	**20%**	17%
SCO price (US$/bbl)	**$ 100.64**	$ 115.65	$ 75.30	**$ 103.86**	$ 77.02
Average realized pricing before risk management[2] (C$/bbl)	**$ 73.80**	$ 82.58	$ 63.21	**$ 74.77**	$ 65.10
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.53**	$ 3.54	$ 3.53	**$ 3.55**	$ 4.08
Average realized pricing before risk management (C$/Mcf)	**$ 3.76**	$ 3.83	$ 3.75	**$ 3.81**	$ 4.26

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

(2) Excludes SCO.

- In Q3/11, WTI pricing decreased by 12% from Q2/11 primarily due to continued high inventory levels of crude oil at Cushing, the relative strength of the US dollar and the impact of increased supply of North American light crude oil.
- The Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI averaged 20% in Q3/11 compared with 20% in Q3/10 and 17% in Q2/11. The WCS heavy differential widened in Q3/11 from the prior quarter partially due to the impact of pipeline transportation restrictions and unplanned outages at refining facilities.
- During Q3/11, the Company contributed approximately 139,000 bbl/d of its heavy crude oil streams to the WCS blend. Canadian Natural is the largest contributor accounting for 55% of the WCS blend.

REDWATER UPGRADING AND REFINING

- In the first quarter of 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership had entered into a 30 year fee-for-service agreement to process bitumen supplied by the Government of Alberta under the Bitumen Royalty In Kind initiative. Project development is dependent upon completion of detailed engineering and final project sanction by the partnership and approval of the final resulting tolls. Board sanction is currently targeted for 2012.

FINANCIAL REVIEW

- The financial position of Canadian Natural remains strong as the Company continues to focus on capital allocation and the execution of implemented strategies. Canadian Natural's credit facilities, its diverse asset base and related capital expenditure programs, and commodity hedging policy all support a flexible financial position and provide the right financial resources for the short, mid and long term. Supporting this are:
  - A large and diverse asset base spread over various commodity types; average production amounted to 578,618 BOE/d in the first nine months of 2011 and 95% of production was located in G8 countries.
  - With cash flow from operations of approximately $4.4 billion in the nine months of 2011 and available unused bank lines of approximately $2.2 billion at September 30, 2011, the Company maintains significant financial stability and liquidity.
  - During the third quarter of 2011, $400 million of US dollar denominated debt securities bearing interest of 6.7% were repaid.
  - Subsequent to Q3/11 Standard and Poor's Financial Services LLC upgraded the Company's unsecured credit rating to BBB+ (Stable outlook) from BBB (Positive outlook).
  - The Company repurchased 3.071 million common shares year-to-date at an average cost of $33.68/share under the Company's Normal Course Issuer Bid.

- Declared a quarterly cash dividend on common shares of $0.09 per common share payable January 1, 2012.
- A strong balance sheet with debt to book capitalization of 30% and debt to EBITDA of 1.2 times; Canadian Natural's long term debt at September 30, 2011 amounted to $9.3 billion compared with $8.5 billion at September 30, 2010.

OUTLOOK

The Company forecasts 2011 production levels before royalties to average between 1,256 and 1,263 MMcf/d of natural gas and between 385,000 and 393,000 bbl/d of crude oil and NGLs. Q4/11 production guidance before royalties is forecast to average between 1,279 and 1,304 MMcf/d of natural gas and between 430,000 and 461,000 bbl/d of crude oil and NGLs. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

DETAILS OF THE 2012 BUDGET

- Equivalent production target of 675,000 to 726,000 BOE/d before royalties, representing a midpoint increase of 17% from the midpoint of 2011 average production guidance. Q4/11 to Q4/12 production is targeted to increase 10% in 2012.

- Crude oil and NGLs production target of 464,000 to 504,000 bbl/d before royalties, representing a midpoint increase of 24% from the midpoint of 2011 guidance. Q4/11 to Q4/12 production is targeted to increase 16%.
  - Primary heavy crude oil is targeted to increase 16% from 2011 to between 114,000 bbl/d and 122,000 bbl/d as a result of the continued strong drilling program and development of our large unproved land base.
  - Thermal in situ is targeted to grow 10% in 2012 to between 104,000 bbl/d and 110,000 bbl/d as a result of continued low cost pad developments at Primrose;
  - Significant increase in North America Light oil and NGL production as a result of enhanced oil recovery ("EOR") projects, a large drilling program consisting of 134 net wells (including 80 net horizontal wells) and the plant expansion at Septimus. Production is targeted to increase 17% in 2012.
  - Increased production reliability at Horizon Oil Sands targeting mid-point guidance of 110,000 bbl/d through 2012. Guidance for 2012 is set at 105,000 bbl/d to 115,000 bbl/d.

- Natural gas production target of 1,265 to 1,334 MMcf/d before royalties, representing a midpoint increase of 3% from the midpoint of 2011 forecasted annual guidance. The increase reflects production from natural gas producing properties acquired in 2011 and continued development of liquids rich natural gas properties.

- Capital spending in 2012 is budgeted at $7.2 billion, an 18% increase over 2011. The Company's balanced asset base and high working interest and operatorship allows for significant flexibility and efficiency in the capital allocation decision making process. Capital flexibility in the 2012 budget is targeted at $3.0 billion.

- The 2012 capital budget reflects:
  - Continuation of significant primary heavy crude oil drilling in 2012 targeting 808 net wells (including over 100 net horizontal wells) which provide significant return on capital.
  - In 2012 the focus at Pelican Lake will be on injection optimization and monitoring polymer response. Pelican Lake capital spending in 2012 includes upgrades to existing batteries, which is necessary to handle additional production. As well, construction of a new battery at Pelican Lake will commence in 2012 with initial start-up capacity designed for 25,000 bbl/d with targeted completion in mid 2013. The new battery will handle the additional polymer driven targeted production from Pelican Lake.
  - Development will continue at Primrose in 2012. The Company is targeting to bring on five additional pads at Primrose East and three additional pads at Primrose South contributing 20,000 bbl/d and 15,000 bbl/d respectively of additional capacity at a cost of approximately $13,000 per flowing barrel of capacity.
  - Budgeted capital for Kirby South Phase 1 is targeted at $710 million to support the completion of engineering, receipt of all major equipment, ramp up of construction, and the completion of three additional pads.

- Budgeted capital expenditures at Horizon for 2012 reflect the Board of Directors approval of approximately $2 billion in targeted strategic expansion. The Company is committed to a disciplined execution strategy and therefore expansion plans will only proceed as cost certainty is achieved.
- North America Light Oil and NGL includes capital allocated to new EOR projects and nine new pool developments.
- International Light Oil activities in 2012 will include a production well at the Tiffany platform in the North Sea as well as workovers at the Ninian platform and a subsea pump installation at the Lyell Field. In Offshore Africa preparations for the Espoir infill drilling program will commence.
- Natural gas spending in 2012 will continue to focus on lease preservation and the Company's liquid rich shale gas plays. In 2012 the plant at Septimus will be expanded to 120 MMcf/d, yielding 10,800 bbl/d of liquids following processing through the plant and deep cut facilities. Targeted net horizontal wells at Septimus are approximately 17 with an additional 30 horizontal wells targeting liquids rich natural gas with horizontal multi frac technology.

▪ Cash Flow is targeted at $8.2 billion to $8.6 billion based on average annual WTI strip pricing of US$88.12/bbl and AECO strip pricing of C$3.45/GJ.

▪ Free cash flow (cash flow after capital excluding acquisitions), is targeted between $1.1 billion and $1.5 billion. Free cash flow will initially be used for opportunistic acquisitions, increased dividends, and debt reduction.

▪ Continued strong balance sheet management which provides financial flexibility for operating plans.

Production and Capital Guidance

Canadian Natural continues its strategy of maintaining a large portfolio of varied projects. This enables the Company to provide consistent growth in production and high shareholder returns over an extended period of time. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of project returns, product pricing expectations, and balance project risks and time horizons. Canadian Natural maintains a high ownership level and operatorship in its properties and can therefore control the nature, timing and extent of expenditures in each of its project areas.

The production guidance for 2012 is as follows:

Daily production volumes, before royalties	**2012 Budget**
Natural gas (MMcf/d)	
North America	**1,245 – 1,305**
North Sea	**4 - 7**
Offshore Africa	**16 - 22**
	1,265 – 1,334
Crude oil and NGLs (Mbbl/d)	
North America – Exploration and Production	**320 - 340**
North America – Oil Sands Mining and Upgrading	**105 - 115**
North Sea	**24 - 29**
Offshore Africa	**15 - 20**
	464 - 504

The budgeted capital expenditures in 2011 and 2012 are as follows:

($ millions)	2011 Forecast	**2012 Budget**
Exploration and Production crude oil and natural gas		
North America natural gas	$ 740	**$ 815**
North America crude oil and NGLs	1,855	**2,010**
North America thermal in situ		
Primrose and Future	810	**710**
Kirby South Phase 1	440	**710**
North Sea	235	**350**
Offshore Africa	60	**130**
Property acquisitions, dispositions and midstream	1,090	**135**
Total Exploration and Production crude oil and natural gas	$ 5,230	**$ 4,860**
Horizon Oil Sands Mining and Upgrading		
Reliability – Tranche 2	$ 275	**$ 165**
Directive 74 and Technology	45	**215**
Phase 2A	125	**345**
Phase 2B	35	**720**
Phase 3	45	**475**
Phase 4	15	**30**
Total Capital Projects	540	**1,950**
Sustaining capital	175	**225**
Turnarounds and reclamation	115	**45**
Capitalized interest and other	50	**135**
Total Horizon Project	$ 880	**$ 2,355**
Total Capital Expenditures	$ 6,110	**$ 7,215**

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

Drilling activity (number of net wells)	2011 Forecast	**2012 Budget**
Targeting natural gas	80	**71**
Targeting crude oil - conventional	1,018	**956**
Targeting thermal in situ	153	**159**
Stratigraphic test / service wells – conventional	41	**97**
Stratigraphic test / service wells – thermal in situ	395	**487**
Stratigraphic test / service wells – mining	317	**230**
Total	2,004	**2,000**

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes and costs, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands future expansion, ability to recover insurance proceeds, Primrose, Pelican Lake, Olowi Field (Offshore Gabon), the Kirby Thermal Oil Sands Project, the Keystone Pipeline US Gulf Coast expansion, and the construction and future operations of the North West Redwater bitumen refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, 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. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; 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; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; 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 thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and natural gas liquids ("NGLs") not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. 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 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 nine months ended September 30, 2011 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2010.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. Common share data and per common share amounts have been restated to reflect the two-for-one share split in May 2010. The Company's consolidated financial statements for the period ended September 30, 2011 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS issued as at November 1, 2011. Any subsequent changes to IFRS that are given effect in the Company's annual consolidated financial statements for the year ending December 31, 2011 could result in restatement of the prior periods. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and cash production costs. These financial measures are not defined by IFRS 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 IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

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 conversion method primarily applicable at the burner tip and does not represent the value equivalency at the wellhead.

Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. 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 nine and three months ended September 30, 2011 in relation to the comparable periods in 2010 and the second quarter of 2011. The accompanying tables form an integral part of this MD&A. This MD&A is dated November 1, 2011. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2010, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Product sales	**$ 3,690**	$ 3,727	$ 3,341	**$ 10,719**	$ 10,535
Net earnings	**$ 836**	$ 929	$ 596	**$ 1,811**	$ 1,982
Per common share – basic	**$ 0.76**	$ 0.85	$ 0.54	**$ 1.65**	$ 1.82
– diluted	**$ 0.76**	$ 0.84	$ 0.54	**$ 1.64**	$ 1.81
Adjusted net earnings from operations (1)	**$ 719**	$ 621	$ 573	**$ 1,568**	$ 1,859
Per common share – basic	**$ 0.65**	$ 0.57	$ 0.53	**$ 1.43**	$ 1.71
– diluted	**$ 0.65**	$ 0.56	$ 0.52	**$ 1.42**	$ 1.70
Cash flow from operations (2)	**$ 1,767**	$ 1,548	$ 1,545	**$ 4,389**	$ 4,681
Per common share – basic	**$ 1.62**	$ 1.41	$ 1.41	**$ 4.01**	$ 4.30
– diluted	**$ 1.60**	$ 1.40	$ 1.41	**$ 3.98**	$ 4.27
Capital expenditures, net of dispositions	**$ 1,406**	$ 1,405	$ 917	**$ 4,505**	$ 3,569

(1) Adjusted net earnings from operations is a non-GAAP measure 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 reconciliation "Adjusted Net Earnings from Operations" presented below 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.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. 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. The reconciliation "Cash Flow from Operations" presented below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

($ millions)	*Three Months Ended*			*Nine Months Ended*	
	Sep 30 2011	*Jun 30 2011*	*Sep 30 2010*	***Sep 30 2011***	*Sep 30 2010*
Net earnings as reported	***$ 836***	*$ 929*	*$ 596*	***$ 1,811***	*$ 1,982*
Share-based compensation recovery, net of tax (a) (e)	***(249)***	*(188)*	*(5)*	***(309)***	*(63)*
Unrealized risk management (gain) loss, net of tax (b)	***(97)***	*(87)*	*71*	***(145)***	*(152)*
Unrealized foreign exchange loss (gain), net of tax (c)	***454***	*(33)*	*(89)*	***332***	*(40)*
Realized foreign exchange gain on repayment of US dollar debt securities (d)	***(225)***	*–*	*–*	***(225)***	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (e)	***–***	*–*	*–*	***104***	*132*
Adjusted net earnings from operations	***$ 719***	*$ 621*	*$ 573*	***$ 1,568***	*$ 1,859*

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(b) Derivative financial instruments are recorded at fair value on the balance sheets, with changes in fair value of non-designated hedges recognized in 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, offset by the impact of cross currency swaps, and are recognized in net earnings.

(d) During the third quarter of 2011, the Company repaid US$400 million of US dollar debt securities bearing interest at 6.7%.

(e) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During the first quarter of 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. The Company's deferred income tax liability was increased by $104 million with respect to this tax rate change. During 2010, changes in Canada to the taxation of stock options surrendered by employees for cash payments resulted in a $132 million charge to deferred income tax expense.

Cash Flow from Operations

($ millions)	Three Months Ended **Sep 30 2011**	Jun 30 2011	Sep 30 2010	Nine Months Ended **Sep 30 2011**	Sep 30 2010
Net earnings	***$ 836***	*$ 929*	*$ 596*	***$ 1,811***	*$ 1,982*
Non-cash items:					
Depletion, depreciation and amortization	***887***	*870*	*898*	***2,606***	*2,574*
Share-based compensation recovery	***(249)***	*(188)*	*(5)*	***(309)***	*(63)*
Asset retirement obligation accretion	***33***	*31*	*31*	***97***	*92*
Unrealized risk management (gain) loss	***(122)***	*(118)*	*92*	***(186)***	*(204)*
Unrealized foreign exchange loss (gain)	***454***	*(33)*	*(101)*	***332***	*(45)*
Realized foreign exchange gain on repayment of US dollar debt securities	***(225)***	*-*	*-*	***(225)***	*-*
Deferred income tax expense	***153***	*57*	*34*	***263***	*345*
Horizon asset impairment provision	***-***	*-*	*-*	***396***	*-*
Insurance recovery – property damage	***-***	*-*	*-*	***(396)***	*-*
Cash flow from operations	***$ 1,767***	*$ 1,548*	*$ 1,545*	***$ 4,389***	*$ 4,681*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the nine months ended September 30, 2011 were $1,811 million compared to $1,982 million for the nine months ended September 30, 2010. Net earnings for the nine months ended September 30, 2011 included net after-tax income of $243 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of realized foreign exchange gain on repayment of long-term debt and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities, compared to net after-tax income of $123 million for the nine months ended September 30, 2010. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2011 were $1,568 million, compared to $1,859 million for the nine months ended September 30, 2010.

Net earnings for the third quarter of 2011 were $836 million compared to $596 million for the third quarter of 2010 and $929 million for the prior quarter. Net earnings for the third quarter of 2011 included net after-tax income of $117 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates and the impact of realized foreign exchange gain on repayment of long-term debt, compared to net after-tax income of $23 million for the third quarter of 2010 and $308 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the third quarter of 2011 were $719 million compared to $573 million for the third quarter of 2010 and $621 million for the prior quarter.

The decrease in adjusted net earnings for the nine months ended September 30, 2011 from the comparable period in 2010 was primarily due to lower synthetic crude oil ("SCO") sales revenue, together with continuing production expenses associated with the suspension of production at Horizon ("Horizon suspension") partially offset by business interruption insurance ("insurance"). On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. Horizon successfully and safely recommenced operations on August 16, 2011.

Other factors contributing to the decrease in adjusted net earnings were:

- lower natural gas netbacks;
- realized risk management losses; and
- the impact of a stronger Canadian dollar;

partially offset by:

- higher North America crude oil and NGL sales volumes; and
- higher crude oil and NGL netbacks.

The increase in adjusted net earnings from the third quarter of 2010 was due to:

- higher North America crude oil and NGL sales volumes; and
- higher crude oil and NGL netbacks;

partially offset by:

- the impact of the Horizon suspension net of insurance;
- lower natural gas netbacks;
- higher administration expense;
- lower realized risk management gains; and
- the impact of a stronger Canadian dollar.

The increase in adjusted net earnings from the prior quarter was due to:

- the recommencement of production at Horizon and insurance;
- realized risk management gains; and
- the impact of a weaker Canadian dollar;

partially offset by lower crude oil and NGL netbacks.

The impacts of share-based compensation, unrealized risk management activities and changes in foreign exchange rates are expected to continue to contribute to quarterly volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the nine months ended September 30, 2011 was $4,389 million compared to $4,681 million for the nine months ended September 30, 2010. Cash flow from operations for the third quarter of 2011 was $1,767 million compared to $1,545 million for the third quarter of 2010 and $1,548 million for the prior quarter. The decrease in cash flow from operations for the nine months ended September 30, 2011 from the comparable period in 2010 was primarily due to the Horizon suspension net of insurance. Other factors contributing to the decrease were:

- lower natural gas netbacks;
- realized risk management losses; and
- the impact of a stronger Canadian dollar;

partially offset by:

- higher North America crude oil and NGL sales volumes; and
- higher crude oil and NGL netbacks.

The increase in cash flow from operations from the third quarter of 2010 was primarily due to:

- higher North America crude oil and NGL sales volumes; and
- higher crude oil and NGL netbacks;

partially offset by:

- the impact of the Horizon suspension net of insurance;
- lower natural gas netbacks;
- higher administration expense;
- lower realized risk management gains; and
- the impact of a stronger Canadian dollar.

The increase in cash flow from operations from the prior quarter was due to:

- the recommencement of production at Horizon and insurance;
- realized risk management gains; and
- the impact of a weaker Canadian dollar;

partially offset by lower crude oil and NGL netbacks.

Total production before royalties for the nine months ended September 30, 2011 decreased 8% to 578,618 BOE/d from 627,052 BOE/d for the nine months ended September 30, 2010. Total production before royalties for the third quarter of 2011 decreased 1% to 612,575 BOE/d from 621,284 BOE/d for the third quarter of 2010 and increased 10% from 556,539 BOE/d for the prior quarter. Production for the third quarter of 2011 was within the Company's previously issued guidance.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)		**Sep 30 2011**		Jun 30 2011		Mar 31 2011		Dec 31 2010
Product sales	**$**	**3,690**	$	3,727	$	3,302	$	3,787
Net earnings (loss)	**$**	**836**	$	929	$	46	$	(309)
Net earnings (loss) per common share								
– basic	**$**	**0.76**	$	0.85	$	0.04	$	(0.28)
– diluted	**$**	**0.76**	$	0.84	$	0.04	$	(0.28)

($ millions, except per common share amounts)		Sep 30 2010		Jun 30 2010		Mar 31 2010(1)		Dec 31 2009(1)(2)
Product sales	$	3,341	$	3,614	$	3,580	$	3,319
Net earnings	$	596	$	651	$	735	$	455
Net earnings per common share								
– basic	$	0.54	$	0.60	$	0.68	$	0.42
– diluted	$	0.54	$	0.60	$	0.67	$	0.42

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

(2) 2009 quarterly results are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – The impact of fluctuating demand, inventory storage levels and geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential ("WCS Differential") from WTI in North America and the impact of the differential between WTI and Dated Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the impact of the suspension and recommencement of production at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates and the impact of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America, and the suspension and recommencement of production at both Horizon and the Olowi Field in Offshore Gabon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the impact of the suspension and recommencement of operations at Horizon and the impact of the ramp up of production and asset impairments at the Olowi Field in Offshore Gabon.
- **Share-based compensation** – Fluctuations due to the mark-to-market movements of the Company's share-based compensation liability.

- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Changes in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
WTI benchmark price (US$/bbl) (1)	**$ 89.81**	$ 102.55	$ 76.21	**$ 95.52**	$ 77.65
Dated Brent benchmark price (US$/bbl)	**$ 113.46**	$ 117.33	$ 76.85	**$ 111.96**	$ 77.15
WCS blend differential from WTI (US$/bbl)	**$ 17.66**	$ 17.62	$ 15.60	**$ 19.32**	$ 12.95
WCS blend differential from WTI (%)	**20%**	17%	20%	**20%**	17%
SCO price (US$/bbl) (2)	**$ 100.64**	$ 115.65	$ 75.30	**$ 103.86**	$ 77.02
Condensate benchmark price (US$/bbl)	**$ 101.73**	$ 112.48	$ 74.52	**$ 104.27**	$ 80.68
NYMEX benchmark price (US$/MMBtu)	**$ 4.19**	$ 4.36	$ 4.42	**$ 4.23**	$ 4.62
AECO benchmark price (C$/GJ)	**$ 3.53**	$ 3.54	$ 3.53	**$ 3.55**	$ 4.08
US / Canadian dollar average exchange rate	**$ 1.0197**	$ 1.0331	$ 0.9624	**$ 1.0224**	$ 0.9656

(1) West Texas Intermediate ("WTI")

(2) Synthetic Crude Oil ("SCO")

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$95.52 per bbl for the nine months ended September 30, 2011, an increase of 23% from US$77.65 per bbl for the nine months ended September 30, 2010. WTI averaged US$89.81 per bbl for the third quarter of 2011, an increase of 18% from US$76.21 per bbl for the third quarter of 2010, and a decrease of 12% from US$102.55 per bbl for the prior quarter. The decrease in the WTI benchmark price for the third quarter of 2011 compared to the prior quarter was due to the continued high inventory levels of crude oil at Cushing, the relative strength of the US dollar, and the impact of increased supply of light crude oil from the Bakken and Eagleford shale plays. The higher Dated Brent ("Brent") pricing relative to WTI in 2011 from the comparable periods in 2010 was due to the limited pipeline capacity between Petroleum Administration for Defence Districts II ("PADD II") and the United States Gulf Coast. This logistical constraint prevents lower WTI priced barrels delivered into the PADD II from obtaining United States Gulf Coast Brent-based pricing.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is more representative of international markets and overall world supply and demand. Brent averaged US$111.96 per bbl for the nine months ended September 30, 2011, an increase of 45% compared to US$77.15 per bbl for the nine months ended September 30, 2010. Brent averaged US$113.46 per bbl for the third quarter of 2011, an increase of 48% compared to US$76.85 per bbl for the third quarter of 2010 and a decrease of 3% from US$117.33 per bbl for the prior quarter.

The Western Canadian Select ("WCS") Heavy Differential averaged 20% for the nine months ended September 30, 2011 compared to 17% for the nine months ended September 30, 2010. The WCS Heavy Differential widened from the comparable period in 2010 partially due to the impact of pipeline disruptions in the last half of 2010 that forced the temporary shutdown and apportionment of major oil pipelines to Midwest refineries in the United States. The WCS Heavy Differential averaged 20% for the third quarter of 2011 and the third quarter of 2010, compared to 17% for the prior quarter. The WCS Heavy Differential widened in the third quarter of 2011, compared to the prior quarter, partially due to the impact of unplanned outages at upgrading facilities.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During 2011, condensate prices traded at a premium to WTI.

The Company anticipates continued volatility in crude oil pricing benchmarks due to supply and demand factors, geopolitical events, and the timing and extent of the continuing economic recovery. The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, logistics and refinery margins.

NYMEX natural gas prices averaged US$4.23 per MMBtu for the nine months ended September 30, 2011, a decrease of 8% from US$4.62 per MMBtu for the nine months ended September 30, 2010. NYMEX natural gas prices averaged US$4.19 per MMBtu for the third quarter of 2011, a decrease of 5% from US$4.42 per MMBtu for the third quarter of 2010, and 4% from US$4.36 per MMBtu for the prior quarter.

AECO natural gas prices for the nine months ended September 30, 2011 averaged $3.55 per GJ, a decrease of 13% from $4.08 per GJ for the nine months ended September 30, 2010. AECO natural gas prices for the third quarter of 2011 averaged $3.53 per GJ and were comparable to the third quarter of 2010 and the prior quarter.

Overall natural gas prices continue to be weak in response to the strong North America supply position, primarily from the highly productive shale areas.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**304,671**	295,715	267,177	**296,892**	265,125
North America – Oil Sands Mining and Upgrading	**50,354**	–	83,809	**19,365**	90,240
North Sea	**26,350**	32,866	27,045	**31,077**	33,828
Offshore Africa	**22,525**	21,334	33,554	**23,105**	31,126
	403,900	349,915	411,585	**370,439**	420,319
Natural gas (MMcf/d)					
North America	**1,226**	1,218	1,234	**1,223**	1,216
North Sea	**5**	7	8	**7**	10
Offshore Africa	**21**	15	16	**19**	14
	1,252	1,240	1,258	**1,249**	1,240
Total barrels of oil equivalent (BOE/d)	**612,575**	556,539	621,284	**578,618**	627,052
Product mix					
Light and medium crude oil and NGLs	**17%**	20%	18%	**19%**	18%
Pelican Lake heavy crude oil	**6%**	6%	6%	**6%**	6%
Primary heavy crude oil	**17%**	18%	15%	**18%**	15%
Bitumen (thermal oil)	**18%**	19%	14%	**18%**	14%
Synthetic crude oil	**8%**	–	13%	**3%**	14%
Natural gas	**34%**	37%	34%	**36%**	33%
Percentage of product sales (1) (excluding midstream revenue)					
Crude oil and NGLs	**85%**	85%	86%	**85%**	84%
Natural gas	**15%**	15%	14%	**15%**	16%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**251,909**	243,943	220,836	**243,202**	218,625
North America – Oil Sands Mining and Upgrading	**48,509**	–	81,077	**18,648**	87,168
North Sea	**26,284**	32,793	27,002	**31,000**	33,760
Offshore Africa	**18,452**	21,196	30,724	**20,936**	29,299
	345,154	297,932	359,639	**313,786**	368,852
Natural gas (MMcf/d)					
North America	**1,189**	1,146	1,213	**1,177**	1,155
North Sea	**5**	7	8	**7**	10
Offshore Africa	**17**	13	15	**16**	13
	1,211	1,166	1,236	**1,200**	1,178
Total barrels of oil equivalent (BOE/d)	**546,861**	492,250	565,595	**513,839**	565,313

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 and medium crude oil and NGLs, Pelican Lake heavy crude oil, primary heavy crude oil, bitumen (thermal oil), and SCO.

Crude oil and NGLs production for the nine months ended September 30, 2011 decreased 12% to 370,439 bbl/d from 420,319 bbl/d for the nine months ended September 30, 2010. Crude oil and NGLs production for the third quarter of 2011 decreased 2% to 403,900 bbl/d from 411,585 bbl/d for the third quarter of 2010, and increased 15% from 349,915 bbl/d for the prior quarter. The decrease from the comparable periods in 2010 was primarily related to the suspension of production at Horizon, partially offset by the impact of a record heavy oil drilling program and the cyclic nature of the Company's thermal operations. The increase from the prior quarter was primarily due to the recommencement of production at Horizon. Crude oil and NGLs production in the third quarter of 2011 was within the Company's previously issued guidance of 373,000 to 414,000 bbl/d.

Natural gas production for the nine months ended September 30, 2011 averaged 1,249 MMcf/d compared to 1,240 MMcf/d for the nine months ended September 30, 2010. Natural gas production for the third quarter of 2011 averaged 1,252 MMcf/d, comparable to production of 1,258 MMcf/d in the third quarter of 2010, and increased 1% compared to 1,240 MMcf/d for the prior quarter. The increase in natural gas production from the nine months ended September 30, 2010 reflects the new production volumes from the Septimus facility in North East British Columbia and from natural gas producing properties acquired during 2010 and 2011. These increases were partially offset by expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity. Natural gas production in the third quarter of 2011 was within the Company's previously issued guidance of 1,230 to 1,255 MMcf/d.

For 2011, revised annual production guidance is targeted to average between 385,000 and 393,000 bbl/d of crude oil and NGLs and between 1,256 and 1,263 MMcf/d of natural gas. Fourth quarter 2011 production guidance is targeted to average between 430,000 and 461,000 bbl/d of crude oil and NGLs and between 1,279 and 1,304 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2011 increased 12% to average 296,892 bbl/d from 265,125 bbl/d for the nine months ended September 30, 2010. For the third quarter of 2011, crude oil and NGLs production increased 14% to average 304,671 bbl/d, compared to 267,177 bbl/d for the third quarter of 2010, and increased 3% compared to 295,715 bbl/d for the prior quarter. Increases in crude oil and NGLs production from comparable periods were primarily due to the impact of a record heavy oil drilling program, the cyclic nature of the Company's thermal operations. The prior quarter was also impacted by the temporary production curtailments of certain fields, including Pelican Lake, due to forest fires in North Central Alberta and flooding in South East Saskatchewan. Production of crude oil and NGLs was within the Company's previously issued guidance of 295,000 bbl/d to 310,000 bbl/d for the third quarter of 2011.

Natural gas production for the nine months ended September 30, 2011 increased 1% to 1,223 MMcf/d compared to 1,216 MMcf/d for the nine months ended September 30, 2010. Natural gas production decreased 1% to 1,226 MMcf/d for the third quarter of 2011 compared to 1,234 MMcf/d in the third quarter of 2010 and increased 1% compared to 1,218 MMcf/d in the prior quarter. Natural gas production for the three and nine months ended September 30, 2011 reflected new production volumes from the Septimus facility in North East British Columbia and the impact of natural gas producing properties acquired during 2010 and 2011, offset by the impact of the expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity. Production of natural gas slightly exceeded the Company's previously issued guidance of 1,205 MMcf/d to 1,225 MMcf/d for the third quarter of 2011.

North America – Oil Sands Mining and Upgrading

On August 16, 2011, the Company successfully and safely recommenced operations in the Oil Sands Mining and Upgrading segment. First pipeline deliveries commenced on August 18, 2011. For the third quarter of 2011, production averaged 50,354 bbl/d compared to 83,809 bbl/d in the third quarter of 2010. As a result of the fire at Horizon's primary upgrading coking plant on January 6, 2011, and the resulting suspension of production, production averaged 19,365 bbl/d for the nine months ended September 30, 2011, compared to 90,240 bbl/d for the nine months ended September 30, 2010. There was no production in the prior quarter. Production averaged 108,000 bbl/day for the month of September 2011.

North Sea

North Sea crude oil production for the nine months ended September 30, 2011 decreased 8% to 31,077 bbl/d from 33,828 bbl/d for the nine months ended September 30, 2010. Third quarter 2011 North Sea crude oil production decreased 3% to 26,350 bbl/d from 27,045 bbl/d for the third quarter of 2010, and decreased 20% from 32,866 bbl/d for the prior quarter. The decrease in production volumes from the comparable periods in 2010 and the prior quarter was due to natural field declines and timing of scheduled maintenance shutdowns. The maintenance shutdowns were completed on time and on budget. Production in the third quarter of 2011 was within the Company's previously issued guidance of 24,000 bbl/d to 27,000 bbl/d.

Offshore Africa

Offshore Africa crude oil production decreased 26% to 23,105 bbl/d for the nine months ended September 30, 2011 from 31,126 bbl/d for the nine months ended September 30, 2010. Third quarter crude oil production averaged 22,525 bbl/d, decreasing 33% from 33,554 bbl/d for the third quarter of 2010 and increasing 6% from 21,334 bbl/d for the prior quarter. The decrease in production volumes from the comparable periods in 2010 was due to natural field declines and the temporary suspension of production at the Olowi Field, Gabon as a result of a failure in the midwater arch. Olowi production was fully reinstated in mid-August, ahead of plan, resulting in production in the third quarter slightly exceeding the Company's previously issued guidance of 19,000 bbl/d to 22,000 bbl/d.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offloading vessels, as follows:

(bbl)	**Sep 30 2011**	Jun 30 2011	Dec 31 2010
North America – Exploration and Production	**825,048**	–	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**1,091,012**	787,517	1,172,200
North Sea	**580,101**	429,391	264,995
Offshore Africa	**1,207,124**	1,158,908	404,197
	3,703,285	2,375,816	2,602,743

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 73.80**	$ 82.58	$ 63.21	**$ 74.77**	$ 65.10
Royalties	**11.52**	11.62	9.05	**11.19**	9.34
Production expense	**16.42**	15.38	15.37	**15.37**	14.38
Netback	**$ 45.86**	$ 55.58	$ 38.79	**$ 48.21**	$ 41.38
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.76**	$ 3.83	$ 3.75	**$ 3.81**	$ 4.26
Royalties	**0.17**	0.24	0.11	**0.18**	0.25
Production expense	**1.15**	1.11	1.05	**1.15**	1.10
Netback	**$ 2.44**	$ 2.48	$ 2.59	**$ 2.48**	$ 2.91
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 55.19**	$ 60.77	$ 47.44	**$ 55.76**	$ 49.68
Royalties	**7.59**	7.83	5.83	**7.43**	6.32
Production expense	**12.83**	12.12	11.89	**12.18**	11.37
Netback	**$ 34.77**	$ 40.82	$ 29.72	**$ 36.15**	$ 31.99

(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.

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 67.81**	$ 77.62	$ 59.13	**$ 69.21**	$ 61.79
North Sea	**$ 109.28**	$ 112.32	$ 81.47	**$ 108.18**	$ 80.40
Offshore Africa	**$ 114.44**	$ 110.42	$ 77.32	**$ 106.93**	$ 78.34
Company average	**$ 73.80**	$ 82.58	$ 63.21	**$ 74.77**	$ 65.10
Natural gas ($/Mcf) (1) (2)					
North America	**$ 3.67**	$ 3.76	$ 3.70	**$ 3.73**	$ 4.23
North Sea	**$ 3.26**	$ 5.19	$ 4.52	**$ 4.05**	$ 4.08
Offshore Africa	**$ 9.38**	$ 8.83	$ 7.36	**$ 8.46**	$ 6.17
Company average	**$ 3.76**	$ 3.83	$ 3.75	**$ 3.81**	$ 4.26
Company average ($/BOE) (1) (2)	**$ 55.19**	$ 60.77	$ 47.44	**$ 55.76**	$ 49.68

(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 realized crude oil prices increased 12% to average $69.21 per bbl for the nine months ended September 30, 2011 from $61.79 per bbl for the nine months ended September 30, 2010. North America realized crude oil prices averaged $67.81 per bbl for the third quarter of 2011, an increase of 15% compared to $59.13 per bbl for the third quarter of 2010 and a decrease of 13% compared to $77.62 per bbl for the prior quarter. The increase in prices for the three and nine months ended September 30, 2011 from the comparable periods in 2010 was primarily a result of higher WTI benchmark pricing, partially offset by the widening WCS Heavy Differential and the impact of a stronger Canadian dollar relative to the US dollar. The decrease in prices for the three months ended September 30, 2011 compared to the prior quarter was primarily a result of the lower benchmark WTI pricing and the widening WCS Heavy Differential partially offset by the impact of a weaker Canadian dollar relative to the US dollar. The Company continues to focus on its crude oil blending marketing strategy, and in the third quarter of 2011 contributed approximately 139,000 bbl/d of heavy crude oil blends to the WCS stream.

In the first quarter of 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership has entered into a 30 year fee-for-service agreement to process bitumen supplied by the Company and the Government of Alberta under the Bitumen Royalty In Kind initiative. Project development is dependent upon completion of detailed engineering and final project sanction by the Company and the partnership and approval of the final resulting tolls. Board sanction is currently targeted for 2012.

North America realized natural gas prices decreased 12% to average $3.73 per Mcf for the nine months ended September 30, 2011 from $4.23 per Mcf for the nine months ended September 30, 2010. North America realized natural gas prices decreased 1% to average $3.67 per Mcf for the third quarter of 2011, compared to $3.70 per Mcf in the third quarter of 2010, and decreased 2% compared to $3.76 per Mcf for the prior quarter. The decrease in natural gas prices from the comparable periods in 2010 was primarily related to the impact of strong supply from US shale projects, together with the impact of a stronger Canadian dollar.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Quarterly Average)	**Sep 30 2011**	Jun 30 2011	Sep 30 2010
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 78.54**	$ 86.49	$ 62.40
Pelican Lake heavy crude oil ($/bbl)	**$ 66.33**	$ 74.95	$ 58.44
Primary heavy crude oil ($/bbl)	**$ 65.08**	$ 75.85	$ 58.97
Bitumen (thermal oil) ($/bbl)	**$ 65.31**	$ 75.73	$ 57.60
Natural gas ($/Mcf)	**$ 3.67**	$ 3.76	$ 3.70

(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 Sea

North Sea realized crude oil prices increased 35% to average $108.18 per bbl for the nine months ended September 30, 2011 from $80.40 per bbl for the nine months ended September 30, 2010. Realized crude oil prices averaged $109.28 per bbl for the third quarter of 2011, an increase of 34% from $81.47 per bbl for the third quarter of 2010, and decreased 3% from $112.32 per bbl for the prior quarter. The fluctuations in realized crude oil prices in the North Sea from the comparable periods in 2010 was primarily the result of fluctuations in Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 36% to average $106.93 per bbl for the nine months ended September 30, 2011 from $78.34 per bbl for the nine months ended September 30, 2010. Realized crude oil prices averaged $114.44 per bbl for the third quarter of 2011, an increase of 48% from $77.32 per bbl for the third quarter of 2010, and an increase of 4% from $110.42 per bbl in the prior quarter. The fluctuations in realized crude oil prices in Offshore Africa from the comparable periods in 2010 was primarily the result of fluctuations in Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.78**	$ 13.53	$ 10.40	**$ 12.31**	$ 10.96
North Sea	**$ 0.27**	$ 0.25	$ 0.13	**$ 0.27**	$ 0.16
Offshore Africa	**$ 20.69**	$ 0.71	$ 6.52	**$ 11.02**	$ 4.95
Company average	**$ 11.52**	$ 11.62	$ 9.05	**$ 11.19**	$ 9.34
Natural gas ($/Mcf) (1)					
North America	**$ 0.15**	$ 0.23	$ 0.10	**$ 0.17**	$ 0.25
Offshore Africa	**$ 1.90**	$ 1.07	$ 0.85	**$ 1.33**	$ 0.46
Company average	**$ 0.17**	$ 0.24	$ 0.11	**$ 0.18**	$ 0.25
Company average ($/BOE) (1)	**$ 7.59**	$ 7.83	$ 5.83	**$ 7.43**	$ 6.32

(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 royalties for the nine months ended September 30, 2011 compared to 2010 reflected benchmark commodity prices.

Crude oil and NGLs royalties averaged approximately 17% of product sales for the third quarter of 2011 compared to 18% for the third quarter of 2010 and 17% for the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 17% to 19% of product sales for 2011.

Natural gas royalties averaged approximately 4% of product sales for the third quarter of 2011, compared to 3% for the third quarter of 2010 and 6% for the prior quarter. The decrease in natural gas royalty rates from the prior quarter was primarily due to gas cost allowance adjustments recorded in the prior quarter. Natural gas royalties are anticipated to average 3% to 5% of product sales for 2011.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of product sales averaged approximately 18% for the third quarter of 2011 compared to 9% for the third quarter of 2010 and 1% for the prior quarter. The increase in royalties from the third quarter of 2010 and the prior quarter was due to payout of the Baobab Field during the second quarter of 2011. The increase in royalties from the prior quarter also reflected royalty adjustments related to the Baobab and Espoir Fields in the second quarter. Offshore Africa royalty rates are anticipated to average 10% to 12% for 2011.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 13.38**	$ 12.86	$ 12.41	**$ 12.84**	$ 12.40
North Sea	**$ 49.72**	$ 34.20	$ 44.45	**$ 37.26**	$ 29.61
Offshore Africa	**$ 19.91**	$ 21.36	$ 13.66	**$ 19.99**	$ 14.95
Company average	**$ 16.42**	$ 15.38	$ 15.37	**$ 15.37**	$ 14.38
Natural gas ($/Mcf) (1)					
North America	**$ 1.13**	$ 1.09	$ 1.04	**$ 1.13**	$ 1.08
North Sea	**$ 2.68**	$ 2.61	$ 2.42	**$ 2.64**	$ 2.97
Offshore Africa	**$ 2.16**	$ 2.35	$ 1.69	**$ 1.86**	$ 1.65
Company average	**$ 1.15**	$ 1.11	$ 1.05	**$ 1.15**	$ 1.10
Company average ($/BOE) (1)	**$ 12.83**	$ 12.12	$ 11.89	**$ 12.18**	$ 11.37

(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 nine months ended September 30, 2011 increased 4% to $12.84 per bbl from $12.40 per bbl for the nine months ended September 30, 2010. North America crude oil and NGLs production expense for the third quarter of 2011 increased 8% to $13.38 per bbl from $12.41 per bbl for the third quarter of 2010 and increased 4% from $12.86 per bbl for the prior quarter. The increase in production expense per barrel from the third quarter of 2010 and the prior quarter was a result of higher overall service costs relating to heavy crude oil production and the timing of thermal steam cycles. North America crude oil and NGLs production expense is anticipated to average $12.00 to $13.00 per bbl for 2011.

North America natural gas production expense for the nine months ended September 30, 2011 increased 5% to $1.13 per Mcf from $1.08 per Mcf for the nine months ended September 30, 2010. North America natural gas production expense for the third quarter of 2011 averaged $1.13 per Mcf and increased 9% compared to $1.04 per Mcf for the third quarter of 2010 and increased 4% compared to $1.09 per Mcf for the prior quarter. Natural gas production expense increased from the comparable periods in 2010 due to acquisitions of natural gas producing properties that have higher operating costs per Mcf than the Company's existing properties. These costs are expected to decline once the acquisitions are fully integrated into the Company's operations. North America natural gas production expense is anticipated to average $1.08 to $1.14 per Mcf for 2011.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2011 increased 26% to $37.26 per bbl from $29.61 per bbl for the nine months ended September 30, 2010. North Sea crude oil production expense for the third quarter of 2011 increased 12% to $49.72 per bbl from $44.45 per bbl for the third quarter of 2010 and increased 45% from $34.20 per bbl for the prior quarter. Production expense increased on a per barrel basis from the comparable periods in 2010 due to lower volumes on relatively fixed costs and increased fuel prices. Production expense increased from the prior quarter due to the impact of planned turnarounds. Production expense is anticipated to average $37.00 to $38.00 per bbl for 2011.

Offshore Africa

Offshore Africa crude oil production expense for the nine months ended September 30, 2011 increased 34% to $19.99 per bbl from $14.95 per bbl for the nine months ended September 30, 2010. Offshore Africa crude oil production expense for the third quarter of 2011 averaged $19.91 per bbl, an increase of 46% compared to $13.66 per bbl for the third quarter of 2010 and a decrease of 7% compared to $21.36 per bbl for the prior quarter. Production expense increased on a per barrel basis from the comparable periods in 2010 due to lower volumes on relatively fixed costs and due to planned turnarounds. Production expense for the third quarter of 2011 was lower than the prior quarter due to the timing of liftings for each field. Production expense is anticipated to average $21.00 to $22.00 per bbl for 2011.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Expense ($ millions)	**$ 809**	$ 835	$ 803	**$ 2,468**	$ 2,276
$/BOE [1]	**$ 15.96**	$ 16.60	$ 16.00	**$ 16.29**	$ 15.59

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

Depletion, depreciation and amortization expense increased for the nine months ended September 30, 2011 compared to 2010 due to higher production in North America and an increase in the estimated future costs to develop the Company’s proved undeveloped reserves. The decrease in depletion, depreciation and amortization expense for the three months ended September 30, 2011 from the prior quarter was primarily due to the impact of lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Expense ($ millions)	**$ 28**	$ 26	$ 24	**$ 82**	$ 71
$/BOE [1]	**$ 0.54**	$ 0.52	$ 0.47	**$ 0.54**	$ 0.48

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

On January 6, 2011, the Company suspended SCO production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. The Company successfully and safely recommenced operations on August 16, 2011. First pipeline deliveries commenced on August 18, 2011. Production averaged 108,000 bbl/day for the month of September 2011.

PRODUCT PRICES AND ROYALTIES – OIL SANDS MINING AND UPGRADING

($/bbl) [1]	Three Months Ended Sep 30 2011	Jun 30 2011[5]	Sep 30 2010	Nine Months Ended Sep 30 2011	Sep 30 2010
SCO sales price [2]	**$ 96.19**	$ –	$ 75.31	**$ 92.45**	$ 76.66
Bitumen value for royalty purposes [3]	**$ 56.54**	$ 69.88	$ 54.13	**$ 59.18**	$ 56.04
Bitumen royalties [4]	**$ 3.48**	$ –	$ 2.57	**$ 3.60**	$ 2.70

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.

(2) Net of transportation.

(3) Calculated as the simple average of the monthly bitumen valuation methodology price.

(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

(5) SCO sales price excludes incidental by-product sales and other adjustments of $3 million.

Realized SCO sales prices averaged $92.45 per bbl for the nine months ended September 30, 2011, an increase of 21% compared to $76.66 per bbl for the nine months ended September 30, 2010. Realized SCO sales prices averaged $96.19 per bbl for the third quarter of 2011, an increase of 28% compared to $75.31 per bbl for the third quarter of 2010.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

($ millions)	Three Months Ended Sep 30 2011	Jun 30 2011	Sep 30 2010	Nine Months Ended Sep 30 2011	Sep 30 2010
Cash costs	**$ 306**	$ 221	$ 268	**$ 783**	$ 904
Less: costs incurred during the period of suspension of production	**(151)**	(221)	–	**(581)**	–
Adjusted cash costs	**$ 155**	$ –	$ 268	**$ 202**	$ 904
Adjusted cash costs, excluding natural gas costs	**$ 144**	$ –	$ 243	**$ 186**	$ 804
Adjusted natural gas costs	**11**	–	25	**16**	100
Adjusted cash production costs	**$ 155**	$ –	$ 268	**$ 202**	$ 904

($/bbl) [1]	Three Months Ended Sep 30 2011	Jun 30 2011	Sep 30 2010	Nine Months Ended Sep 30 2011	Sep 30 2010
Adjusted cash costs, excluding natural gas costs	**$ 33.13**	$ –	$ 31.20	**$ 34.70**	$ 32.40
Adjusted natural gas costs	**2.72**	–	3.15	**3.02**	4.03
Adjusted cash production costs	**$ 35.85**	$ –	$ 34.35	**$ 37.72**	$ 36.43
Sales (bbl/d)	**47,218**	–	84,836	**19,663**	90,896

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.

Adjusted cash production costs averaged $37.72 per bbl for the nine months ended September 30, 2011, an increase of 4% compared to $36.43 per bbl for the nine months ended September 30, 2010. Adjusted cash production costs for the third quarter of 2011 averaged $35.85 per bbl, an increase of 4% compared to $34.35 per bbl for the third quarter of 2010.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions)	Three Months Ended Sep 30 2011	Three Months Ended Jun 30 2011	Three Months Ended Sep 30 2010	Nine Months Ended Sep 30 2011	Nine Months Ended Sep 30 2010
Depletion, depreciation and amortization	**$ 77**	$ 33	$ 93	**$ 133**	$ 292
Less: depreciation incurred during the period of suspension of production	**(21)**	(33)	–	**(64)**	–
Adjusted depletion, depreciation and amortization	**$ 56**	$ –	$ 93	**$ 69**	$ 292
$/bbl (1)	**$ 13.00**	$ –	$ 11.89	**$ 12.88**	$ 11.76

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.

Adjusted depletion, depreciation and amortization expense for the nine months ended September 30, 2011 decreased from the nine months ended September 30, 2010 primarily due to the impact of the suspension of production of synthetic crude oil in January 2011. Depletion, depreciation and amortization expense per barrel increased for the three and nine months ended September 30, 2011 from the comparable periods due to the impact of depreciation determined on a straight-line basis.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended Sep 30 2011	Three Months Ended Jun 30 2011	Three Months Ended Sep 30 2010	Nine Months Ended Sep 30 2011	Nine Months Ended Sep 30 2010
Expense ($ millions)	**$ 5**	$ 5	$ 7	**$ 15**	$ 21
$/bbl (1)	**$ 1.14**	$ –	$ 0.93	**$ 2.77**	$ 0.88

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

MIDSTREAM

($ millions)	Three Months Ended Sep 30 2011	Three Months Ended Jun 30 2011	Three Months Ended Sep 30 2010	Nine Months Ended Sep 30 2011	Nine Months Ended Sep 30 2010
Revenue	**$ 23**	$ 21	$ 19	**$ 66**	$ 59
Production expense	**7**	5	4	**19**	16
Midstream cash flow	**16**	16	15	**47**	43
Depreciation	**1**	2	2	**5**	6
Segment earnings before taxes	**$ 15**	$ 14	$ 13	**$ 42**	$ 37

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended Sep 30 2011	Three Months Ended Jun 30 2011	Three Months Ended Sep 30 2010	Nine Months Ended Sep 30 2011	Nine Months Ended Sep 30 2010
Expense ($ millions)	**$ 65**	$ 69	$ 43	**$ 188**	$ 157
$/BOE (1)	**$ 1.17**	$ 1.38	$ 0.73	**$ 1.20**	$ 0.92

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

Administration expense for the nine and three months ended September 30, 2011 increased from the comparable periods in 2010 primarily due to higher staffing related costs.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Sep 30 2011	Jun 30 2011	Sep 30 2010	Nine Months Ended Sep 30 2011	Sep 30 2010
Recovery	**$ (249)**	$ (188)	$ (5)	**$ (309)**	$ (63)

The Company’s stock option plan provides current employees with the right to receive common shares or a direct cash payment in exchange for options surrendered.

The Company recorded a $309 million share-based compensation recovery for the nine months ended September 30, 2011 primarily as a result of remeasurement of the fair value of outstanding options at the end of the period, offset by normal course graded vesting of options granted in prior periods and the impact of vested options exercised or surrendered during the period. For the nine months ended September 30, 2011, the Company recovered $19 million in share-based compensation previously capitalized to Oil Sands Mining and Upgrading (September 30, 2010 – capitalized $13 million).

For the nine months ended September 30, 2011, the Company paid $12 million for stock options surrendered for cash settlement (September 30, 2010 – $39 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts)	Three Months Ended Sep 30 2011	Jun 30 2011	Sep 30 2010	Nine Months Ended Sep 30 2011	Sep 30 2010
Expense, gross	**$ 113**	$ 112	$ 116	**$ 330**	$ 347
Less: capitalized interest	**16**	13	7	**40**	19
Expense, net	**$ 97**	$ 99	$ 109	**$ 290**	$ 328
$/BOE (1)	**$ 1.75**	$ 1.97	$ 1.89	**$ 1.85**	$ 1.92
Average effective interest rate	**4.6%**	4.7%	4.9%	**4.7%**	4.8%

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

Gross interest and other financing costs for the three and nine months ended September 30, 2011 decreased from the comparable periods in 2010 due to the impact of a stronger Canadian dollar on US dollar denominated debt, partially offset by higher variable interest rates. Gross interest and other financing costs were comparable to the prior quarter.

The Company's average effective interest rates for the three and nine months ended September 30, 2011 were comparable to 2010 and the prior quarter.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2011**	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Crude oil and NGLs financial instruments	**$ 26**	$ 37	$ 5	**$ 90**	$ 37
Natural gas financial instruments	**–**	–	(85)	**–**	(181)
Foreign currency contracts and interest rate swaps	**(49)**	(3)	10	**(9)**	22
Realized (gain) loss	**$ (23)**	$ 34	$ (70)	**$ 81**	$ (122)
Crude oil and NGLs financial instruments	**$ (71)**	$ (135)	$ 8	**$ (139)**	$ (216)
Natural gas financial instruments	**–**	–	56	**–**	20
Foreign currency contracts and interest rate swaps	**(51)**	17	28	**(47)**	(8)
Unrealized (gain) loss	**$ (122)**	$ (118)	$ 92	**$ (186)**	$ (204)
Net (gain) loss	**$ (145)**	$ (84)	$ 22	**$ (105)**	$ (326)

Complete details related to outstanding derivative financial instruments at September 30, 2011 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized gain of $186 million ($145 million after-tax) on its risk management activities for the nine months ended September 30, 2011, including an unrealized gain of $122 million ($97 million after-tax) for the third quarter of 2011 (June 30, 2011 – unrealized gain of $118 million, $87 million after-tax; September 30, 2010 – unrealized loss of $92 million, $71 million after-tax), primarily due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2011**	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Net realized (gain) loss	**$ (243)**	$ (4)	$ 11	**$ (225)**	$ (8)
Net unrealized loss (gain) (1)	**454**	(33)	(101)	**332**	(45)
Net loss (gain)	**$ 211**	$ (37)	$ (90)	**$ 107**	$ (53)

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net unrealized foreign exchange loss for the nine months ended September 30, 2011 was primarily due to the weakening of the Canadian dollar in the third quarter with respect to US dollar debt as well as the reversal of the unrealized foreign exchange gain on the settlement of the 6.7% US dollar denominated debt securities. The net unrealized gain for each of the periods presented included the impact of cross currency swaps (three months ended September 30, 2011 – unrealized gain of $150 million, June 30, 2011 – unrealized loss of $16 million, September 30, 2010 – unrealized loss of $62 million; nine months ended September 30, 2011 – unrealized gain of $84 million, September 30, 2010 – unrealized loss of $30 million). The net realized foreign exchange gain for the nine months ended September 30, 2011 was primarily due to the settlement of the 6.7% US dollar denominated debt securities and foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the third quarter at US$0.9626 (June 30, 2011- US $1.0370; December 31, 2010 – US$1.0054; September 30, 2010 – US$0.9711).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2011	Jun 30 2011	Sep 30 2010	Nine Months Ended Sep 30 2011	Sep 30 2010
North America (1)	**$ 26**	$ 79	$ 114	**$ 196**	$ 382
North Sea	**45**	70	23	**161**	119
Offshore Africa	**46**	24	26	**90**	41
PRT expense – North Sea	**42**	46	5	**96**	54
Other taxes	**6**	6	5	**18**	17
Current income tax	**165**	225	173	**561**	613
Deferred income tax expense	**157**	55	36	**255**	343
Deferred PRT expense – North Sea	**(4)**	2	(2)	**8**	2
Deferred income tax	**153**	57	34	**263**	345
	318	282	207	**824**	958
Income tax rate and other legislative changes (2)	**–**	–	–	**(104)**	(132)
	$ 318	$ 282	$ 207	**$ 720**	$ 826
Effective income tax rate on adjusted net earnings from operations(3)	**25.7%**	24.1%	26.7%	**26.2%**	27.3%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) Deferred income tax expense in the first quarter of 2011 included a charge of $104 million related to substantively enacted changes in the UK to increase the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. Deferred income tax expense in the first quarter of 2010 included a charge of $132 million related to changes in Canada to the taxation of stock options surrendered by employees for cash.

(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in periods subsequent to the current reporting period. North America current and deferred income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

Deferred income tax expense in the first quarter of 2010 included a charge of $132 million related to changes in Canada to the taxation of stock options surrendered by employees for cash.

During the first quarter of 2011, the UK government substantively enacted an increase to the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million as at March 31, 2011.

Subsequent to September 30, 2011, the Canadian Federal government substantively enacted legislation to implement several taxation changes that could impact the Company. These changes include a requirement that partnership income be included in the taxable income of its corporate partners based on the tax year of the partner, rather than the fiscal year of the partnership, beginning in 2012. The legislation includes a transition period to amortize the impact of the change over a five year period.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

For 2011, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $250 million to $300 million in Canada and $500 million to $540 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2011	Three Months Ended Jun 30 2011	Three Months Ended Sep 30 2010	Nine Months Ended Sep 30 2011	Nine Months Ended Sep 30 2010
Exploration and Evaluation					
Net expenditures	**$ 85**	$ 41	$ 38	**$ 200**	$ 163
Property, Plant and Equipment					
Net property acquisitions	**127**	265	45	**616**	993
Land acquisition and retention	**12**	10	11	**32**	29
Seismic evaluations	**12**	17	14	**38**	34
Well drilling, completion and equipping	**437**	284	364	**1,293**	1,056
Production and related facilities	**419**	382	253	**1,218**	811
Net expenditures	**1,007**	958	687	**3,197**	2,923
Total Exploration and Production expenditures	**1,092**	999	725	**3,397**	3,086
Oil Sands Mining and Upgrading:					
Horizon Phases 2/3 construction costs	**126**	115	92	**331**	219
Coker rebuild and collateral damage costs	**80**	183	–	**389**	–
Sustaining capital	**38**	50	35	**112**	80
Turnaround costs	**14**	24	–	**93**	–
Capitalized interest, share-based compensation and other	**(3)**	(2)	13	**15**	68
Total Oil Sands Mining and Upgrading [2]	**255**	370	140	**940**	367
Midstream	**1**	1	3	**5**	4
Abandonments [3]	**54**	29	45	**147**	99
Head office	**4**	6	4	**16**	13
Total net capital expenditures	**$ 1,406**	$ 1,405	$ 917	**$ 4,505**	$ 3,569
By segment					
North America	**$ 1,045**	$ 913	$ 610	**$ 3,190**	$ 2,769
North Sea	**46**	69	59	**156**	111
Offshore Africa	**1**	17	56	**51**	206
Oil Sands Mining and Upgrading	**255**	370	140	**940**	367
Midstream	**1**	1	3	**5**	4
Abandonments [3]	**54**	29	45	**147**	99
Head office	**4**	6	4	**16**	13
Total	**$ 1,406**	$ 1,405	$ 917	**$ 4,505**	$ 3,569

(1) The net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.
(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 nine months ended September 30, 2011 were $4,505 million compared to $3,569 million for the nine months ended September 30, 2010. Net capital expenditures for the third quarter of 2011 were $1,406 million compared to $917 million for the third quarter of 2010 and $1,405 million for the prior quarter.

The increase in capital expenditures for the nine months ended September 30, 2011 from the comparable period in 2010 was primarily due to an increase in well drilling and completion expenditures related to the Company's heavy oil drilling program, an increase in the Company's abandonment program and costs associated with the coker rebuild and collateral damage resulting from the coker fire. The increase in capital expenditures for the third quarter of 2011 from the comparable period in 2010 was due to higher property acquisitions, an increase in well drilling and completion expenditures related to the Company's heavy oil drilling program and costs associated with the coker rebuild and collateral damage.

Drilling Activity (number of wells)

	Three Months Ended			Nine Months Ended	
	Sep 30 2011	Jun 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Net successful natural gas wells	**21**	10	19	**56**	74
Net successful crude oil wells (1)	**317**	177	281	**773**	616
Dry wells	**10**	5	9	**31**	25
Stratigraphic test / service wells	**25**	19	14	**545**	320
Total	**373**	211	323	**1,405**	1,035
Success rate (excluding stratigraphic test / service wells)	**97%**	97%	97%	**96%**	97%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 74% of the total capital expenditures for the nine months ended September 30, 2011 compared to approximately 81% for the nine months ended September 30, 2010.

During the third quarter of 2011, the Company targeted 21 net natural gas wells, including 5 wells in Northeast British Columbia, 13 wells in Northwest Alberta and 3 wells in the Northern Plains. The Company also targeted 327 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 228 primary heavy crude oil wells, 22 Pelican Lake heavy crude oil wells, 1 light crude oil well and 38 bitumen (thermal oil) wells were drilled. Another 38 wells targeting light crude oil were drilled outside the Northern Plains region.

As part of the phased expansion of its in situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production for the third quarter of 2011 averaged approximately 110,000 bbl/d, compared to approximately 85,000 bbl/d for the third quarter of 2010 and approximately 106,000 bbl/d for the prior quarter.

The next planned phase of the Company's in situ Oil Sands Assets expansion is the Kirby South Phase 1 Project. Currently the Company is proceeding with the detailed engineering and design work. During the third quarter of 2010, the Company received final regulatory approval for Phase 1 of the Project. During the fourth quarter of 2010, the Company's Board of Directors sanctioned Kirby South Phase 1. Construction has commenced, with first steam targeted in 2013.

Development of the tertiary recovery conversion projects at Pelican Lake continued in the third quarter of 2011. No horizontal wells were drilled during the quarter. Response from the polymer flood project continues to be positive, but delayed from the original plan. Pelican Lake production averaged approximately 38,000 bbl/d for the third quarter of 2011, compared to 38,000 bbl/d in the third quarter of 2010 and 35,000 bbl/d for the prior quarter. Production in the prior quarter was lower due to the temporary impact of the forest fires in North Central Alberta.

For the fourth quarter of 2011, the Company's overall planned drilling activity in North America is expected to be comprised of 23 net natural gas wells and 368 net crude oil wells excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. During the third quarter of 2011, final mechanical, testing and commissioning activities were completed, and production resumed.

Phase 2/3 spending during the third quarter of 2011 continued to be focused on construction of the third Ore Preparation Plant and associated hydro-transport, additional product tankage, the butane treatment unit and the sulphur recovery unit. Commissioning of the Ore Preparation Plant and associated hydro-transport is currently targeted for mid-fourth quarter of 2011.

During the first quarter of 2011, the Company recognized a Horizon asset impairment provision of $396 million, net of accumulated depletion and depreciation, related to the property damage resulting from the fire in the primary upgrading coking plant. As the Company believes that its insurance coverage is adequate to mitigate all significant property damage related losses, estimated insurance proceeds receivable of $396 million were also recognized offsetting such property damage. The final Horizon asset impairment provision and related insurance recoveries are subject to revision upon determination of final costs to restore plant operating capacity. Accordingly, actual results may differ from the amounts currently recognized.

The Company also maintains business interruption insurance to reduce operating losses related to its ongoing Horizon operations. During the third quarter of 2011, the Company recognized additional business interruption insurance recoveries of $181 million (nine months ended September 30, 2011 – $317 million) based on interim payments and submissions to date. Additional business interruption insurance recoveries will be recognized at such time as the final terms of the insurance settlement are determined.

North Sea

During the third quarter of 2011, the Company continued workover and drilling operations on the Ninian South Platform.

In March 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. This resulted in an increase to the overall corporate tax rate applicable to net operating income from oil and gas activities to 62% for non-PRT paying fields and 81% for PRT paying fields, after allowing for deductions for capital and abandonment expenditures.

As a result of the increase in the corporate income tax rate, the Company's development activities in 2011 in the North Sea were reduced. The Company is continuing to high grade all North Sea prospects for potential development opportunities in 2012 and future years.

Offshore Africa

During the second quarter of 2011, production at the Olowi Field was temporarily suspended as a result of the failure of a midwater arch system that provides support for production and gas lift flowlines and the main power line. All necessary safety and environmental precautions were undertaken to temporarily cease operations. Olowi production was fully reinstated in mid-August.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2011**	Jun 30 2011	Dec 31 2010	Sep 30 2010
Working capital (deficit) (1)	**$ (213)**	$ (1,032)	$ (1,200)	$ (694)
Long-term debt (2) (3)	**$ 9,327**	$ 8,624	$ 8,485	$ 8,481
Share capital	**$ 3,431**	$ 3,425	$ 3,147	$ 3,015
Retained earnings	**18,642**	17,989	17,212	17,602
Accumulated other comprehensive loss	**71**	38	9	95
Shareholders' equity	**$ 22,144**	$ 21,452	$ 20,368	$ 20,712
Debt to book capitalization (3) (4)	**30%**	29%	29%	29%
Debt to market capitalization (3) (5)	**22%**	16%	15%	18%
After-tax return on average common shareholders' equity (6)	**7%**	6%	8%	–
After-tax return on average capital employed (3) (7)	**6%**	5%	7%	–

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Includes the current portion of long-term debt.

(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.

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

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

(6) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the period. The ratio for the trailing period ended September 30, 2010 has not been presented as the period would include 2009 amounts based on Canadian GAAP as previously reported and therefore may not be comparable.

(7) Calculated as net earnings plus after-tax interest and other financing costs for the twelve month trailing period; as a percentage of average capital employed for the period. The ratio for the trailing period ended September 30, 2010 has not been presented as the period would include 2009 amounts based on Canadian GAAP as previously reported and therefore may not be comparable.

At September 30, 2011, the Company's capital resources consisted primarily of cash flow from operations, available bank 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, 2010 annual MD&A. The Company's ability to renew existing bank 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. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its on-going hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

During the third quarter of 2011, the Company repaid US$400 million of US dollar denominated debt securities bearing interest at 6.7%. During the second quarter of 2011, the $2,230 million revolving syndicated credit facility was increased to $3,000 million and extended to June 2015. Each of the $3,000 million and $1,500 million facilities is extendible annually for one year periods at the mutual agreement of the Company and the lenders. At September 30, 2011, the Company had $2,162 million of available credit under its bank credit facilities. During the fourth quarter of 2010, the Company repaid $400 million of the medium-term notes bearing interest at 5.50%.

Subsequent to September 30, 2011, the Company filed base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2013. If issued, these securities will bear interest as determined at the date of issuance.

Subsequent to September 30, 2011, Standard and Poor's Financial Services LLC upgraded the Company's unsecured credit rating to BBB+ (Stable outlook) from BBB (Positive outlook).

Long-term debt was $9,327 million at September 30, 2011, resulting in a debt to book capitalization ratio of 30% (June 30, 2011- 29%; December 31, 2010 – 29%; September 30, 2010 – 29%). This ratio is below the 35% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occur. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its crude oil production for 2011 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at June 30, 2011 are discussed in note 7 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of put options is in addition to the above parameters. As at September 30, 2011, in accordance with the policy, approximately 11% of budgeted crude oil volumes were hedged using collars for 2011. Further details related to the Company's commodity related derivative financial instruments outstanding at September 30, 2011 are discussed in note 15 to the Company's unaudited interim consolidated financial statements.

Share capital

As at September 30, 2011, there were 1,094,747,000 common shares outstanding and 60,738,000 stock options outstanding. As at November 1, 2011, the Company had 1,094,837,000 common shares outstanding and 60,477,000 stock options outstanding.

On March 1, 2011, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.36 per common share for 2011. The increase represents a 20% increase from 2010, recognizing the stability of the Company's cash flow and providing a return to shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

On March 31, 2011, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the 12 month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. As at September 30, 2011, 2,700,000 common shares had been purchased for cancellation at an average price of $34.05 per common share, for a total cost of $92 million. Subsequent to September 30, 2011, 371,100 common shares were purchased for cancellation at an average price of $31.00 per common share, for a total cost of $12 million.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and NYSE during the 12 month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. A total of 2,000,000 common shares were purchased for cancellation under this Normal Course Issuer Bid at an average price of $33.77 per common share, for a total cost of $68 million.

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. As at September 30, 2011, no entities were consolidated under the Standing Interpretations Committee ("SIC") 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at September 30, 2011:

($ millions)	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 58	$ 220	$ 204	$ 193	$ 181	$ 1,009
Offshore equipment operating leases	$ 55	$ 103	$ 101	$ 102	$ 84	$ 176
Long-term debt (1)	$ –	$ 364	$ 815	$ 364	$ 2,828	$ 4,986
Interest and other financing costs (2)	$ 102	$ 464	$ 425	$ 405	$ 333	$ 4,413
Office leases	$ 7	$ 29	$ 33	$ 34	$ 32	$ 336
Other	$ 55	$ 69	$ 21	$ 20	$ 24	$ 10

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

(2) Interest and other financing cost amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at September 30, 2011.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company has identified, developed and tested systems and accounting and reporting processes and changes required to capture data required for IFRS accounting and reporting, including 2010 requirements to capture both Canadian GAAP and IFRS data.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises would be required to adopt IFRS as issued by the IASB in place of Canadian GAAP effective January 1, 2011.

The Company has completed its transition to IFRS. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the IASB. The interim consolidated financial statements for the nine months ended September 30, 2011 have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting" and IFRS 1, "First-time Adoption of International Financial Reporting Standards".

The accounting policies adopted by the Company under IFRS are set out in note 1 to the interim consolidated financial statements for the nine months ended September 30, 2011. Note 18 to the interim consolidated financial statements discloses the impact of the transition to IFRS on the Company's reported financial position, earnings and cash flows, including the nature and effect of certain transition elections and significant changes in accounting policies from those used in the Company's Canadian GAAP consolidated financial statements for 2010.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2013, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 “Consolidated Financial Statements” replaces IAS 27 “Consolidated and Separate Financial Statements” (IAS 27 still contains guidance for Separate Financial Statements) and SIC 12 “Consolidation – Special Purpose Entities”. IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.
- IFRS 11 “Joint Arrangements” replaces IAS 31 “Interests in Joint Ventures” and SIC 13 “Jointly Controlled Entities – Non-Monetary Contributions by Venturers”. The new standard defines two types of joint arrangements, joint operations and joint ventures, and prescribes the accounting treatment for each type of joint arrangement – proportionate consolidation and equity accounting, respectively. There is no longer a choice of the accounting method.
- IFRS 12 “Disclosure of Interests in Other Entities”. The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company’s accounting for investments in other entities, but will impact the Company’s disclosures.
- IFRS 13 “Fair Value Measurement” provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value.

In June 2011, the IASB issued amendments to IAS 1 “Presentation of Financial Statements” that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012.

The Company is currently assessing the impact of these new and amended standards on its consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from those estimates, and those differences may be material.

Critical accounting estimates are reviewed by the Company’s Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

Depletion, Depreciation and Amortization and Impairment

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment losses. Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

Exploration and evaluation (“E&E”) asset costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and estimated costs associated with retiring the assets. Exploration and evaluation assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved reserves are determined to exist. The judgements associated with the estimation of proved reserves are described below in “Crude Oil and Natural Gas Reserves”.

An alternative acceptable accounting method for E&E assets under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves, increases in estimated future exploration expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves, increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the specific assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

Crude Oil and Natural Gas Reserves

The estimation of reserves involves the exercise of judgement. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that, over time, its reserve estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of crude oil and natural gas property, plant and equipment carrying amounts.

Asset Retirement Obligations

The Company is required to recognize a liability for asset retirement obligations ("ARO") associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions can be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 5.1%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas increases or decreases due to changes in interest rates and estimated future cash flows are capitalized to property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will be due.

Risk Management Activities

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

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Purchase Price Allocations

Purchase prices related to business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgments relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

Share-based compensation

The Company has made various assumptions in estimating the fair values of the common stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, options outstanding are remeasured for changes in the fair value of the liability.

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	Note	**Sep 30 2011**	Dec 31 2010	Jan 1 2010
ASSETS				
Current assets				
Cash and cash equivalents		**$ 18**	$ 22	$ 13
Accounts receivable		**1,998**	1,481	1,148
Inventory		**625**	477	438
Prepaids and other		**165**	129	146
		2,806	2,109	1,745
Exploration and evaluation assets	4	**2,372**	2,402	2,293
Property, plant and equipment	5	**39,928**	38,429	37,018
Other long-term assets	6	**369**	14	6
		$ 45,475	$ 42,954	$ 41,062
LIABILITIES				
Current liabilities				
Accounts payable		**$ 445**	$ 274	$ 240
Accrued liabilities		**2,093**	1,735	1,430
Current income tax liabilities		**296**	430	94
Current portion of long-term debt	7	**–**	397	400
Current portion of other long-term liabilities	8	**185**	870	854
		3,019	3,706	3,018
Long-term debt	7	**9,327**	8,088	9,259
Other long-term liabilities	8	**2,882**	3,004	2,485
Deferred income tax liabilities		**8,103**	7,788	7,462
		23,331	22,586	22,224
SHAREHOLDERS' EQUITY				
Share capital	11	**3,431**	3,147	2,834
Retained earnings		**18,642**	17,212	15,927
Accumulated other comprehensive income	12	**71**	9	77
		22,144	20,368	18,838
		$ 45,475	$ 42,954	$ 41,062

Commitments and contingencies (Note 16)

Approved by the Board of Directors on November 1, 2011

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2011	Three Months Ended Sep 30 2010	Nine Months Ended Sep 30 2011	Nine Months Ended Sep 30 2010
Product sales		**$ 3,690**	$ 3,341	**$ 10,719**	$ 10,535
Less: royalties		**(400)**	(313)	**(1,145)**	(990)
Revenue		**3,290**	3,028	**9,574**	9,545
Expenses					
Production		**959**	867	**2,637**	2,573
Transportation and blending		**459**	350	**1,745**	1,323
Depletion, depreciation and amortization	5	**887**	898	**2,606**	2,574
Administration		**65**	43	**188**	157
Share-based compensation	8	**(249)**	(5)	**(309)**	(63)
Asset retirement obligation accretion	8	**33**	31	**97**	92
Interest and other financing costs		**97**	109	**290**	328
Risk management activities	15	**(145)**	22	**(105)**	(326)
Foreign exchange loss (gain)		**211**	(90)	**107**	(53)
Horizon asset impairment provision	9	**–**	–	**396**	–
Insurance recovery – property damage	9	**–**	–	**(396)**	–
Insurance recovery – business interruption	9	**(181)**	–	**(317)**	–
		2,136	2,225	**6,939**	6,605
Earnings before taxes		**1,154**	803	**2,635**	2,940
Current income tax expense	10	**165**	173	**561**	613
Deferred income tax expense	10	**153**	34	**263**	345
Net earnings		**$ 836**	$ 596	**$ 1,811**	$ 1,982
Net earnings per common share					
Basic	14	**$ 0.76**	$ 0.54	**$ 1.65**	$ 1.82
Diluted	14	**$ 0.76**	$ 0.54	**$ 1.64**	$ 1.81

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2011	Three Months Ended Sep 30 2010	Nine Months Ended Sep 30 2011	Nine Months Ended Sep 30 2010
Net earnings	**$ 836**	$ 596	**$ 1,811**	$ 1,982
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $6 million (2010 – $18 million) – three months ended; $5 million (2010 – $5 million) – nine months ended	**46**	(71)	**44**	23
Reclassification to net earnings, net of taxes of $4 million (2010 – $nil million) – three months ended; $13 million (2010 – $1 million) – nine months ended	**12**	(1)	**41**	(4)
	58	(72)	**85**	19
Foreign currency translation adjustment				
Translation of net investment	**(25)**	(2)	**(23)**	(1)
Other comprehensive income (loss), net of taxes	**33**	(74)	**62**	18
Comprehensive income	**$ 869**	$ 522	**$ 1,873**	$ 2,000

Consolidated Statements of Changes in Equity

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended **Sep 30 2011**	Sep 30 2010
Share capital	11		
Balance – beginning of period		**$ 3,147**	$ 2,834
Issued upon exercise of stock options		**192**	83
Previously recognized liability on stock options exercised for common shares		**100**	104
Purchase of common shares under Normal Course Issuer Bid		**(8)**	(6)
Balance – end of period		**3,431**	3,015
Retained earnings			
Balance – beginning of period		**17,212**	15,927
Net earnings		**1,811**	1,982
Purchase of common shares under Normal Course Issuer Bid	11	**(84)**	(62)
Dividends on common shares	11	**(297)**	(245)
Balance – end of period		**18,642**	17,602
Accumulated other comprehensive income	12		
Balance – beginning of period		**9**	77
Other comprehensive income, net of taxes		**62**	18
Balance – end of period		**71**	95
Shareholders' equity		**$ 22,144**	$ 20,712

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Sep 30 2011	Three Months Ended Sep 30 2010	Nine Months Ended Sep 30 2011	Nine Months Ended Sep 30 2010
Operating activities					
Net earnings		**$ 836**	$ 596	**$ 1,811**	$ 1,982
Non-cash items					
Depletion, depreciation and amortization		**887**	898	**2,606**	2,574
Share-based compensation		**(249)**	(5)	**(309)**	(63)
Asset retirement obligation accretion		**33**	31	**97**	92
Unrealized risk management (gain) loss		**(122)**	92	**(186)**	(204)
Unrealized foreign exchange loss (gain)		**454**	(101)	**332**	(45)
Realized foreign exchange gain on repayment of US dollar debt securities		**(225)**	–	**(225)**	–
Deferred income tax expense		**153**	34	**263**	345
Horizon asset impairment provision	9	**–**	–	**396**	–
Insurance recovery – property damage	9	**–**	–	**(396)**	–
Other		**9**	4	**(9)**	(12)
Abandonment expenditures		**(54)**	(45)	**(147)**	(99)
Net change in non-cash working capital		**(469)**	85	**(303)**	175
		1,253	1,589	**3,930**	4,745
Financing activities					
Issue (repayment) of bank credit facilities, net		**652**	(651)	**985**	(1,094)
Repayment of US dollar debt securities		**(390)**	–	**(390)**	–
Issue of common shares on exercise of stock options		**11**	9	**192**	83
Purchase of common shares under Normal Course Issuer Bid		**(92)**	(68)	**(92)**	(68)
Dividends on common shares		**(99)**	(82)	**(279)**	(220)
Net change in non-cash working capital		**(5)**	(4)	**(10)**	(8)
		77	(796)	**406**	(1,307)
Investing activities					
Expenditures on exploration and evaluation assets and property, plant and equipment		**(1,352)**	(872)	**(4,358)**	(3,470)
Investment in other long-term assets		**–**	–	**(346)**	–
Net change in non-cash working capital		**34**	87	**364**	46
		(1,318)	(785)	**(4,340)**	(3,424)
Increase (decrease) in cash and cash equivalents		**12**	8	**(4)**	14
Cash and cash equivalents – beginning of period		**6**	19	**22**	13
Cash and cash equivalents – end of period		**$ 18**	$ 27	**$ 18**	$ 27
Interest paid		**$ 151**	$ 150	**$ 376**	$ 382
Income taxes paid		**$ 141**	$ 108	**$ 516**	$ 114

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations and an electricity co-generation system.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2500, 855-2 Street S.W., Calgary, Alberta.

In 2010, the Canadian Institute of Chartered Accountants ("CICA") Handbook was revised to incorporate International Financial Reporting Standards ("IFRS") and require publicly accountable enterprises to apply IFRS effective for years beginning on or after January 1, 2011. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the International Accounting Standards Board. These interim consolidated financial statements have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting" and IFRS 1, "First-time Adoption of International Financial Reporting Standards". Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed.

The accounting policies adopted by the Company under IFRS are set out below and are based on IFRS issued and outstanding as at November 1, 2011. Subject to certain transition elections disclosed in Note 18, the Company has consistently applied the same accounting policies in its opening IFRS balance sheet at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect. Any subsequent changes to IFRS that are given effect in the Company's annual consolidated financial statements for the year ending December 31, 2011 may result in restatement of these interim consolidated financial statements, including the adjustments recognized on transition to IFRS.

Comparative information for 2010 has been restated from Canadian Generally Accepted Accounting Principles ("Canadian GAAP") to comply with IFRS. In these consolidated financial statements, Canadian GAAP refers to Canadian GAAP before the adoption of IFRS. Note 18 discloses the impact of the transition to IFRS on the Company's reported financial position, earnings and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company's Canadian GAAP consolidated financial statements for the year ended December 31, 2010. These interim consolidated financial statements should be read in conjunction with the Company's 2010 annual consolidated financial statements, which were prepared in accordance with Canadian GAAP, and in consideration of the IFRS disclosures included in Note 18 to these interim consolidated financial statements.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and partnerships. Certain of the Company's activities are conducted through joint arrangements where the Company has a direct ownership interest in jointly controlled assets. The revenue, expenses, assets and liabilities related to the jointly controlled assets are included in the consolidated financial statements in proportion to the Company's interest.

(B) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents in the consolidated balance sheets.

(C) INVENTORIES

Inventories are primarily comprised of product inventory and materials and supplies. Product inventory includes crude oil held for sale, pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, direct overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value is determined by reference to forward prices as at the date of the consolidated balance sheets.

(D) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves. The Company accounts for E&E costs in accordance with the requirements of IFRS 6 "Exploration for and Evaluation of Mineral Resources".

E&E costs are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and the estimated costs associated with retiring the assets. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area, which are recognized immediately in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved reserves are determined to exist.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated reserves, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(E) PROPERTY, PLANT AND EQUIPMENT

Exploration and Production

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

The cost of an asset comprises its acquisition, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included in property, plant and equipment.

The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined as described in Note 18.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Horizon is comprised of both mining and upgrading operations and accordingly, capitalized costs are reported in a separate operating segment from the Company's North America Exploration and Production segment. Capitalized mining activity costs include property acquisition, construction and development costs, the estimate of any asset retirement costs, and applicable borrowing costs. Construction and development costs are capitalized separately to each phase of Horizon. The construction and development of a particular phase of Horizon is considered complete once the phase is available for its intended use.

Mine-related costs and costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on Horizon proved reserves or productive capacity. Moveable mine-related equipment is depreciated on a straight-line basis over its estimated useful life.

Midstream and head office

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets. Midstream assets are depreciated on a straight-line basis over their estimated lives. Head office assets are amortized on a declining balance basis.

Useful lives

The expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in useful lives accounted for prospectively.

Derecognition

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is recognized in net earnings.

Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and amortized over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the asset in prior periods. Such reversal is recognized in net earnings. After a reversal, the depletion charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

(F) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are amortized over the life of the mining reserves that directly benefit from the overburden removal activity.

(G) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

(H) LEASES

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in net earnings over the lease term.

(I) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the present obligation at the date of the balance sheet. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas increases/decreases due to changes in interest rates and the estimated future cash flows are capitalized to property, plant, and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(J) FOREIGN CURRENCY TRANSLATION

(i) Functional and presentation currency

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheet, and revenue and expenses are translated at the average rate for the period. Cumulative foreign currency translation adjustments are recognized in other comprehensive income.

When the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at balance sheet date exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency of the Company are recognized in net earnings.

(K) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue represents the Company's share net of royalty payments to governments and other mineral interest owners. Related costs of goods sold are comprised of production, transportation and blending, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(L) PRODUCTION SHARING CONTRACTS

Production generated from Offshore Africa is currently shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective Government State Oil Companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the PSCs.

(M) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carry forwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carry forwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carry forwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date. Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(N) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model. Expected volatility is estimated based on historic results. Re-measurements are recognized in each reporting period. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital.

(O) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: fair value through profit or loss; held-to-maturity investments; loans and receivables; and financial liabilities measured at amortized cost. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash, cash equivalents, and accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities measured at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized immediately in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

Impairment of financial assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized.

Impairment losses on financial assets carried at amortized cost including loans and receivables are calculated as the difference between the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(P) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value as determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. The Company's own credit risk is not included in the carrying amount of a risk management liability.

The Company documents all derivative financial instruments that are formally 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 periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are included in risk management activities in net earnings.

The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its 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. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in net earnings.

Cross currency swap contracts are periodically used 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. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges related to the notional principal amounts are included in foreign exchange gains and losses in net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged items are 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. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized immediately in net earnings.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized on the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent changes in fair value. The fair value adjustment on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the long-term debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when realized. Changes in the fair value of foreign currency forward contracts not included as hedges are included in risk management activities and recognized immediately in net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

(Q) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company’s net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

(R) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company’s stock option plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

(S) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction, net of tax, from proceeds. When common shares are repurchased, share capital is reduced by the average carrying value of the shares repurchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Repurchased shares are cancelled upon purchase.

(T) DIVIDENDS

Dividends on common shares are recognized in the Company’s financial statements in the period in which the dividends are approved by the Board of Directors.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, “Financial Instruments”, effective January 1, 2013, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, “Financial Instruments - Recognition and Measurement”. The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 “Consolidated Financial Statements” replaces IAS 27 “Consolidated and Separate Financial Statements” (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee (“SIC”) 12 “Consolidation – Special Purpose Entities”. IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.
- IFRS 11 “Joint Arrangements” replaces IAS 31 “Interests in Joint Ventures” and SIC 13 “Jointly Controlled Entities – Non-Monetary Contributions by Venturers”. The new standard defines two types of joint arrangements, joint operations and joint ventures, and prescribes the accounting treatment for each type of joint arrangement – proportionate consolidation and equity accounting, respectively. There is no longer a choice of the accounting method.
- IFRS 12 “Disclosure of Interests in Other Entities”. The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company’s accounting for investments in other entities, but will impact the Company’s disclosures.
- IFRS 13 “Fair Value Measurement” provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value.

In June 2011, the IASB issued amendments to IAS 1 “Presentation of Financial Statements” that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012.

The Company is currently assessing the impact of these new and amended standards on its consolidated financial statements.

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The Company has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(a) Estimates of crude oil and natural gas reserves

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices.

(b) Asset retirement obligations

The calculation of asset retirement obligations includes estimates of the future costs and the timing of the cash flows to settle the liability, the discount rate used in reflecting the passage of time, and future inflation rates.

(c) Income taxes

The Company is subject to income taxes in numerous jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will be due.

(d) Fair value of derivatives and other financial instruments

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

(e) Purchase price allocations

Purchase prices related to business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

(f) Share-based compensation

The Company has made various assumptions in estimating the fair values of the common stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, options outstanding are remeasured for changes in the fair value of the liability.

(g) Identification of cash generating units

Cash generating units are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into cash generating units requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Company's operations.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At January 1, 2010	$ 2,102	$ –	$ 191	$ –	$ 2,293
Additions	563	6	3	–	572
Transfer to property, plant and equipment	(299)	–	(154)	–	(453)
Foreign exchange adjustments	–	(1)	(9)	–	(10)
At December 31, 2010	2,366	5	31	–	2,402
Additions	**199**	**–**	**1**	**–**	**200**
Transfer to property, plant and equipment	**(225)**	**(4)**	**–**	**–**	**(229)**
Foreign exchange adjustments	**–**	**(1)**	**–**	**–**	**(1)**
At September 30, 2011	**$ 2,340**	**$ –**	**$ 32**	**$ –**	**$ 2,372**

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At January 1, 2010	$ 36,159	$ 3,866	$ 2,666	$ 13,758	$ 284	$ 214	$ 56,947
Additions	4,403	190	254	411	7	18	5,283
Transfer from E&E assets	299	–	154	–	–	–	453
Disposals/ derecognition	–	(5)	–	–	–	(11)	(16)
Foreign exchange adjustments and other	–	(238)	(146)	–	–	(5)	(389)
At December 31, 2010	40,861	3,813	2,928	14,169	291	216	62,278
Additions	**3,021**	**156**	**50**	**945**	**5**	**16**	**4,193**
Transfer from E&E assets	**225**	**4**	**–**	**–**	**–**	**–**	**229**
Disposals/ derecognition (1)	**–**	**–**	**(29)**	**(411)**	**–**	**–**	**(440)**
Foreign exchange adjustments and other	**–**	**181**	**134**	**–**	**–**	**–**	**315**
At September 30, 2011	**$ 44,107**	**$ 4,154**	**$ 3,083**	**$ 14,703**	**$ 296**	**$ 232**	**$ 66,575**
Accumulated depletion and depreciation							
At January 1, 2010	$ 16,427	$ 2,054	$ 1,008	$ 207	$ 81	$ 152	$ 19,929
Expense	2,473	295	298	396	8	13	3,483
Product inventory costing	(5)	(5)	21	4	–	–	15
Impairment (2)	–	–	637	–	–	–	637
Disposals/ derecognition	–	(5)	–	–	–	(11)	(16)
Foreign exchange adjustments and other	–	(134)	(60)	–	–	(5)	(199)
At December 31, 2010	18,895	2,205	1,904	607	89	149	23,849
Expense	**2,104**	**182**	**170**	**133**	**5**	**12**	**2,606**
Product inventory costing	**4**	**8**	**(10)**	**16**	**–**	**–**	**18**
Impairment (1)	**–**	**–**	**–**	**396**	**–**	**–**	**396**
Disposals/ derecognition (1)	**–**	**–**	**(29)**	**(411)**	**–**	**–**	**(440)**
Foreign exchange adjustments and other	**–**	**113**	**105**	**–**	**–**	**–**	**218**
At September 30, 2011	**$ 21,003**	**$ 2,508**	**$ 2,140**	**$ 741**	**$ 94**	**$ 161**	**$ 26,647**
Net book value							
- at September 30, 2011	**$ 23,104**	**$ 1,646**	**$ 943**	**$ 13,962**	**$ 202**	**$ 71**	**$ 39,928**
- at December 31, 2010	$ 21,966	$ 1,608	$ 1,024	$ 13,562	$ 202	$ 67	$ 38,429
- at January 1, 2010	$ 19,732	$ 1,812	$ 1,658	$ 13,551	$ 203	$ 62	$ 37,018

(1) During the first quarter of 2011, the Company derecognized certain property, plant and equipment related to the coker fire incident at Horizon in the amount of $411 million, net of accumulated depletion and depreciation of $15 million, resulting in an impairment charge of $396 million. For additional information, refer to Note 9.

(2) During 2010, the Company recognized a $637 million impairment relating to Gabon, Offshore Africa, which was included in depletion, depreciation and amortization expense. The impairment was based on the difference between the December 31, 2010 net book value of the assets and their recoverable amounts. The recoverable amounts were determined using fair value less costs to sell based on discounted future cash flows of proved and probable reserves using forecast prices and costs.

Development projects not subject to depletion

At September 30, 2011	$	1,280
At December 31, 2010	$	934
At January 1, 2010	$	1,270

The Company acquired a number of producing crude oil and natural gas assets in the Exploration and Production segments for total consideration of $616 million during the nine months ended September 30, 2011 (year ended December 31, 2010 – $1,482 million).

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once construction is substantially complete. For the nine months ended September 30, 2011, pre-tax interest of $40 million was capitalized to property, plant and equipment (September 30, 2010 – $19 million) using a capitalization rate of 4.7% (September 30, 2010 – 4.8%).

6. OTHER LONG-TERM ASSETS

	Sep 30 2011	Dec 31 2010	Jan 1 2010
Investment in North West Redwater Partnership	**$ 346**	$ –	$ –
Other	**23**	14	6
	$ 369	$ 14	$ 6

Other long-term assets include a $346 million equity investment in the 50% owned North West Redwater Partnership ("Redwater"). Redwater has entered into an agreement to construct and operate a bitumen refinery, which targets to process bitumen for the Company and the Government of Alberta under a 30 year fee-for-service contract. Project development is dependent upon completion of detailed engineering and final project sanction by the Company and Redwater and approval of the final resulting tolls.

7. LONG-TERM DEBT

	Sep 30 2011	Dec 31 2010	Jan 1 2010
Canadian dollar denominated debt			
Bank credit facilities	**$ 2,428**	$ 1,436	$ 1,897
Medium-term notes	**800**	800	1,200
	3,228	2,236	3,097
US dollar denominated debt			
US dollar debt securities (September 30, 2011-US$5,900 million; December 31, 2010 and January 1, 2010-US$6,300 million)	**6,129**	6,266	6,594
Less – original issue discount on US dollar debt securities (1)	**(19)**	(20)	(22)
	6,110	6,246	6,572
Fair value impact of interest rate swaps on US dollar debt securities (2)	**36**	47	39
	6,146	6,293	6,611
Long-term debt before transaction costs	**9,374**	8,529	9,708
Less: transaction costs (1) (3)	**(47)**	(44)	(49)
	9,327	8,485	9,659
Less: current portion (1)	**–**	397	400
	$ 9,327	$ 8,088	$ 9,259

(1) *The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying amount of the outstanding debt.*

(2) *The carrying amounts of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 were adjusted by $36 million (December 2010 – $47 million, January 2010 – $39 million) to reflect the fair value impact of hedge accounting.*

(3) *Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.*

Bank Credit Facilities

As at September 30, 2011, the Company had in place unsecured bank credit facilities of $4,724 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $3,000 million maturing June 2015;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter of 2011, the $2,230 million revolving syndicated credit facility was increased to $3,000 million and extended to June 2015. Each of the $3,000 million and $1,500 million facilities is 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. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at September 30, 2011, was 2.3% (September 30, 2010 – 1.6%), and on long-term debt outstanding for the nine months ended September 30, 2011 was 4.7% (September 30, 2010 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $462 million, including $145 million related to Horizon and $178 million related to North Sea operations, were outstanding at September 30, 2011. Subsequent to September 30, 2011 the financial guarantee related to Horizon was reduced to $130 million.

Medium-Term Notes

Subsequent to September 30, 2011, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2013. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

During the third quarter of 2011, the Company repaid US$400 million of US dollar debt securities bearing interest at 6.7%.

Subsequent to September 30, 2011, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2013. If issued, these securities will bear interest as determined at the date of issuance.

8. OTHER LONG-TERM LIABILITIES

	Sep 30 2011	Dec 31 2010	Jan 1 2010
Asset retirement obligations	**$ 2,645**	$ 2,624	$ 2,214
Share-based compensation	**223**	663	622
Risk management (Note 15)	**110**	485	325
Other	**89**	102	178
	3,067	3,874	3,339
Less: current portion	**185**	870	854
	$ 2,882	$ 3,004	$ 2,485

Asset retirement obligations

The Company's asset retirement obligations will be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.1% (December 31, 2010 – 5.1%; January 1, 2010 – 5.8%). A reconciliation of the discounted asset retirement obligations is as follows:

	Sep 30 2011	Dec 31 2010
Balance – beginning of period	$ 2,624	$ 2,214
Liabilities incurred	9	12
Liabilities acquired	24	22
Liabilities settled	(147)	(179)
Asset retirement obligation accretion	97	123
Revision of estimates	–	474
Foreign exchange	38	(42)
Balance – end of period	$ 2,645	$ 2,624

Share-based compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested options are surrendered for cash settlement.

	Sep 30 2011	Dec 31 2010
Balance – beginning of period	$ 663	$ 622
Share-based compensation (recovery) expense	(309)	203
Cash payment for options surrendered	(12)	(45)
Transferred to common shares	(100)	(149)
Capitalized (recovered) to Oil Sands Mining and Upgrading	(19)	32
Balance – end of period	223	663
Less: current portion	155	623
	$ 68	$ 40

9. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. During the third quarter of 2011, final mechanical, testing and commissioning activities were completed, and production resumed.

During the first quarter of 2011, the Company recognized a Horizon asset impairment provision of $396 million, net of accumulated depletion and depreciation, related to the property damage resulting from the fire in the primary upgrading coking plant. As the Company believes that its insurance coverage is adequate to mitigate all significant property damage related losses, estimated insurance proceeds receivable of $396 million were also recognized, offsetting such property damage. The final Horizon asset impairment provision and related insurance recoveries are subject to revision upon determination of final costs to restore plant operating capacity. Accordingly, actual results may differ from the amounts currently recognized.

The Company also maintains business interruption insurance to reduce operating losses related to its ongoing Horizon operations. During the third quarter of 2011, the Company recognized additional business interruption insurance recoveries of $181 million (nine months ended September 30, 2011 – $317 million) based on interim payments and submissions to date. Additional business interruption insurance recoveries will be recognized at such time as the final terms of the insurance settlement are determined.

10. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Current corporate income tax – North America	**$ 26**	$ 114	**$ 196**	$ 382
Current corporate income tax – North Sea	**45**	23	**161**	119
Current corporate income tax – Offshore Africa	**46**	26	**90**	41
Current PRT(1) expense – North Sea	**42**	5	**96**	54
Other taxes	**6**	5	**18**	17
Current income tax expense	**165**	173	**561**	613
Deferred corporate income tax expense	**157**	36	**255**	343
Deferred PRT expense – North Sea	**(4)**	(2)	**8**	2
Deferred income tax expense	**153**	34	**263**	345
Income tax expense	**$ 318**	$ 207	**$ 824**	$ 958

(1) Petroleum Revenue Tax

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in periods subsequent to the current reporting period. North America current and deferred income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

Deferred income tax expense in the first quarter of 2010 included a charge of $132 million related to changes in Canada to the taxation of stock options surrendered by employees for cash.

During the first quarter of 2011, the UK government substantively enacted an increase to the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million as at March 31, 2011.

Subsequent to September 30, 2011, the Canadian Federal government substantively enacted legislation to implement several taxation changes that could impact the Company. These changes include a requirement that partnership income be included in the taxable income of its corporate partners based on the tax year of the partner, rather than the fiscal year of the partnership, beginning in 2012. The legislation includes a transition provision to amortize the impact of the change over a five year period.

11. SHARE CAPITAL

Authorized

200,000 Class 1 preferred shares with a stated value of $10.00 each.

Unlimited number of common shares without par value.

Issued common shares	Nine months ended Sep 30, 2011 **Number of shares** (thousands)		**Amount**
Balance – beginning of period	**1,090,848**	$	**3,147**
Issued upon exercise of stock options	**6,599**		**192**
Previously recognized liability on stock options exercised for common shares	**–**		**100**
Purchase of common shares under Normal Course Issuer Bid	**(2,700)**		**(8)**
Balance – end of period	**1,094,747**	$	**3,431**

Dividend Policy

On March 1, 2011, the Board of Directors set the regular quarterly dividend at $0.09 per common share (2010 – $0.075 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.

Normal Course Issuer Bid

In 2011, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. As at September 30, 2011, the Company had purchased 2,700,000 common shares at an average price of $34.05 per common share, for a total cost of $92 million. Retained earnings was reduced by $84 million, representing the excess of the purchase price of the common shares over their average carrying value.

Subsequent to September 30, 2011, 371,100 common shares were purchased for cancellation at an average price of $31.00 per common share, for a total cost of $12 million.

Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2011:

	Nine months ended Sep 30, 2011 **Stock options** (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**66,844**	**$**	**33.31**
Granted	**3,818**	**$**	**40.15**
Surrendered for cash settlement	**(842)**	**$**	**29.72**
Exercised for common shares	**(6,599)**	**$**	**29.14**
Forfeited	**(2,483)**	**$**	**35.62**
Outstanding – end of period	**60,738**	**$**	**34.15**
Exercisable – end of period	**19,112**	**$**	**31.37**

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

	Sep 30 2011	Sep 30 2010
Derivative financial instruments designated as cash flow hedges	**$ 118**	$ 96
Foreign currency translation adjustment	**(47)**	(1)
	$ 71	$ 95

During the next twelve months, $13 million is expected to be reclassified to net earnings from accumulated other comprehensive income, reducing net earnings.

13. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 35% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At September 30, 2011, the ratio was below the target range at 30%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	Sep 30 2011	Dec 31 2010	Jan 1 2010
Long-term debt (1)	**$ 9,327**	$ 8,485	$ 9,659
Total shareholders' equity	**$ 22,144**	$ 20,368	$ 18,838
Debt to book capitalization	**30%**	29%	34%

(1) Includes the current portion of long-term debt.

14. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Weighted average common shares outstanding – basic (thousands of shares)	**1,096,750**	1,088,989	**1,095,753**	1,087,794
Effect of dilutive stock options (thousands of shares)	**4,673**	5,794	**8,103**	7,324
Weighted average common shares outstanding – diluted (thousands of shares)	**1,101,423**	1,094,783	**1,103,856**	1,095,118
Net earnings	**$ 836**	$ 596	**$ 1,811**	$ 1,982
Net earnings per common share – basic	**$ 0.76**	$ 0.54	**$ 1.65**	$ 1.82
– diluted	**$ 0.76**	$ 0.54	**$ 1.64**	$ 1.81

15. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

	Sep 30, 2011				
Asset (liability)	**Loans and receivables at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,998**	**$ –**	**$ –**	**$ –**	**$ 1,998**
Accounts payable	**–**	**–**	**–**	**(445)**	**(445)**
Accrued liabilities	**–**	**–**	**–**	**(2,093)**	**(2,093)**
Other long-term liabilities	**–**	**18**	**(128)**	**(81)**	**(191)**
Long-term debt	**–**	**–**	**–**	**(9,327)**	**(9,327)**
	$ 1,998	**$ 18**	**$ (128)**	**$ (11,946)**	**$ (10,058)**

	Dec 31, 2010				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,481	$ –	$ –	$ –	$ 1,481
Accounts payable	–	–	–	(274)	(274)
Accrued liabilities	–	–	–	(1,735)	(1,735)
Other long-term liabilities	–	(167)	(318)	(91)	(576)
Long-term debt (1)	–	–	–	(8,485)	(8,485)
	$ 1,481	$ (167)	$ (318)	$ (10,585)	$ (9,589)

	Jan 1, 2010				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,148	$ –	$ –	$ –	$ 1,148
Accounts payable	–	–	–	(240)	(240)
Accrued liabilities	–	–	–	(1,430)	(1,430)
Other long-term liabilities	–	(182)	(143)	(167)	(492)
Long-term debt (1)	–	–	–	(9,659)	(9,659)
	$ 1,148	$ (182)	$ (143)	$ (11,496)	$ (10,673)

(1) Includes the current portion of long-term debt.

The carrying amount of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below. The fair values of the Company's financial assets and liabilities are outlined below:

	Sep 30, 2011		
	Carrying amount	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	**$ (110)**	**$ –**	**$ (110)**
Fixed-rate long-term debt (2) (3)	**(6,899)**	**(7,989)**	**–**
	$ (7,009)	**$ (7,989)**	**$ (110)**

	Dec 31, 2010		
	Carrying amount	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (485)	$ –	$ (485)
Fixed-rate long-term debt (2) (3) (4)	(7,049)	(7,835)	–
	$ (7,534)	$ (7,835)	$ (485)

	Jan 1, 2010		
	Carrying amount	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (325)	$ –	$ (325)
Fixed-rate long-term debt (2) (3) (4)	(7,762)	(8,212)	–
	$ (8,087)	$ (8,212)	$ (325)

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) The carrying amounts of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $36 million (December 31, 2010 – $47 million, January 1, 2010 – $39 million) to reflect the fair value impact of hedge accounting.

(3) The fair value of fixed rate long-term debt has been determined based on quoted market prices.

(4) Includes the current portion of long-term debt.

The following provides a summary of the carrying amounts of derivative contracts held and reconciliation to the Company's consolidated balance sheets.

Asset (liability)	Sep 30, 2011	Dec 31, 2010	Jan 1, 2010
Derivatives held for trading			
Crude oil price collars	**$ 5**	$ (64)	$ (256)
Crude oil put options	**(12)**	(83)	–
Natural gas price collars	**–**	–	72
Interest rate swaps	**–**	–	11
Foreign currency forward contracts	**25**	(20)	(9)
Cash flow hedges			
Natural gas swaps	**(16)**	(49)	–
Cross currency swaps	**(112)**	(269)	(158)
Fair value hedges			
Interest rate swaps	**–**	–	15
	$ (110)	$ (485)	$ (325)
Included within:			
Current portion of other long-term liabilities	**$ 3**	$ (222)	$ (182)
Other long-term liabilities	**(113)**	(263)	(143)
	$ (110)	$ (485)	$ (325)

Ineffectiveness arising from cash flow hedges recognized in the consolidated statements of earnings for the nine months ended September 30, 2011 resulted in a gain of $1 million (December 31, 2010 – loss of $1 million).

Risk Management

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

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

	Nine Months Ended Sep 30, 2011	Year Ended Dec 31, 2010
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ (485)**	$ (325)
Net cost of outstanding put options	**28**	106
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**186**	38
Interest expense	**–**	16
Foreign exchange	**86**	(101)
Other comprehensive income	**103**	(58)
Settlement of interest rate swaps and other	**–**	(55)
	(82)	(379)
Add: put premium financing obligations (1)	**(28)**	(106)
Balance – end of period	**(110)**	(485)
Less: current portion	**3**	(222)
	$ (113)	$ (263)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations were reflected in the net risk management asset (liability).

Net (gains) losses from risk management activities were as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2011	Sep 30 2010	**Sep 30 2011**	Sep 30 2010
Net realized risk management (gain) loss	**$ (23)**	$ (70)	**$ 81**	$ (122)
Net unrealized risk management (gain) loss	**(122)**	92	**(186)**	(204)
	$ (145)	$ 22	**$ (105)**	$ (326)

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At September 30, 2011, the Company had the following derivative financial instruments outstanding to manage its commodity price risks:

i) Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Oct 2011	–	Dec 2011	50,000 bbl/d	US$70.00	–	US $102.23	WTI
Crude oil puts	Oct 2011	–	Dec 2011	100,000 bbl/d			US$70.00	WTI

During the fourth quarter of 2011, US$27 million of put option costs will be settled.

ii) Purchase contracts

	Remaining term			Volume	Weighted average fixed rate	Index
Natural gas						
Swaps – floating to fixed	Oct 2011	–	Dec 2011	125,000 GJ/d	C$4.87	AECO

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

The natural gas derivative financial instruments designated as hedges at September 30, 2011 were classified as cash flow hedges.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts 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. At September 30, 2011, the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount	Fixed rate	Floating rate
Interest rate						
Swaps – floating to fixed	Oct 2011	–	Feb 2012	C$200	1.4475%	3 month CDOR (1)

(1) Canadian Dealer Offered Rate

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. 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. At September 30, 2011, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Oct 2011	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Oct 2011	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2011	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at September 30, 2011, were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at September 30, 2011, the Company had US$1,420 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

b) Credit Risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At September 30, 2011, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At September 30, 2011, the Company had net risk management assets of $14 million with specific counterparties related to derivative financial instruments (December 31, 2010 – $nil, January 1, 2010 – $7 million).

c) Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 445	$ –	$ –	$ –
Accrued liabilities	$ 2,093	$ –	$ –	$ –
Current income tax liabilities	$ 296	$ –	$ –	$ –
Risk management	$ –	$ 26	$ 77	$ 10
Other long-term liabilities	$ 33	$ 12	$ 36	$ –
Long-term debt (1)	$ –	$ 1,179	$ 3,451	$ 4,727

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

16. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 58	$ 220	$ 204	$ 193	$ 181	$ 1,009
Offshore equipment operating leases	$ 55	$ 103	$ 101	$ 102	$ 84	$ 176
Office leases	$ 7	$ 29	$ 33	$ 34	$ 32	$ 336
Other	$ 55	$ 69	$ 21	$ 20	$ 24	$ 10

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

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production															
	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Segmented product sales	**2,730**	2,221	**8,643**	7,197	**276**	224	**907**	755	**250**	290	**638**	623	**3,256**	2,735	**10,188**	8,575
Less: royalties	**(339)**	(268)	**(1,056)**	(882)	**–**	–	**(2)**	(1)	**(46)**	(25)	**(68)**	(40)	**(385)**	(293)	**(1,126)**	(923)
Segmented revenue	**2,391**	1,953	**7,587**	6,315	**276**	224	**905**	754	**204**	265	**570**	583	**2,871**	2,442	**9,062**	7,652
Segmented expenses																
Production	**493**	422	**1,417**	1,259	**114**	123	**309**	280	**45**	52	**120**	121	**652**	597	**1,846**	1,660
Transportation and blending	**454**	344	**1,726**	1,305	**3**	2	**10**	7	**1**	1	**1**	1	**458**	347	**1,737**	1,313
Depletion, depreciation and amortization	**714**	623	**2,114**	1,826	**51**	72	**184**	220	**44**	108	**170**	230	**809**	803	**2,468**	2,276
Asset retirement obligation accretion	**18**	13	**53**	39	**8**	9	**24**	27	**2**	2	**5**	5	**28**	24	**82**	71
Realized risk management activities	**(23)**	(70)	**81**	(122)	**–**	–	**–**	–	**–**	–	**–**	–	**(23)**	(70)	**81**	(122)
Horizon asset impairment provision	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery – property damage (Note 9)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery - business interruption (Note 9)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**1,656**	1,332	**5,391**	4,307	**176**	206	**527**	534	**92**	163	**296**	357	**1,924**	1,701	**6,214**	5,198
Segmented earnings (loss) before the following	**735**	621	**2,196**	2,008	**100**	18	**378**	220	**112**	102	**274**	226	**947**	741	**2,848**	2,454
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing costs																
Unrealized risk management activities																
Foreign exchange loss (gain)																
Total non-segmented expenses																
Earnings before taxes																
Current income tax expense																
Deferred income tax expense																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Segmented product sales	**427**	604	**516**	1,949	**23**	19	**66**	59	**(16)**	(17)	**(51)**	(48)	**3,690**	3,341	**10,719**	10,535
Less: royalties	**(15)**	(20)	**(19)**	(67)	**–**	–	**–**	–	**–**	–	**–**	–	**(400)**	(313)	**(1,145)**	(990)
Segmented revenue	**412**	584	**497**	1,882	**23**	19	**66**	59	**(16)**	(17)	**(51)**	(48)	**3,290**	3,028	**9,574**	9,545
Segmented expenses																
Production	**306**	268	**783**	904	**7**	4	**19**	16	**(6)**	(2)	**(11)**	(7)	**959**	867	**2,637**	2,573
Transportation and blending	**15**	15	**46**	46	**–**	–	**–**	–	**(14)**	(12)	**(38)**	(36)	**459**	350	**1,745**	1,323
Depletion, depreciation and amortization	**77**	93	**133**	292	**1**	2	**5**	6	**–**	–	**–**	–	**887**	898	**2,606**	2,574
Asset retirement obligation accretion	**5**	7	**15**	21	**–**	–	**–**	–	**–**	–	**–**	–	**33**	31	**97**	92
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(23)**	(70)	**81**	(122)
Horizon asset impairment provision	**–**	–	**396**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**396**	–
Insurance recovery – property damage (Note 9)	**–**	–	**(396)**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(396)**	–
Insurance recovery – business interruption (Note 9)	**(181)**	–	**(317)**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(181)**	–	**(317)**	–
Total segmented expenses	**222**	383	**660**	1,263	**8**	6	**24**	22	**(20)**	(14)	**(49)**	(43)	**2,134**	2,076	**6,849**	6,440
Segmented earnings (loss) before the following	**190**	201	**(163)**	619	**15**	13	**42**	37	**4**	(3)	**(2)**	(5)	**1,156**	952	**2,725**	3,105
Non-segmented expenses																
Administration													**65**	43	**188**	157
Share-based compensation													**(249)**	(5)	**(309)**	(63)
Interest and other financing costs													**97**	109	**290**	328
Unrealized risk management activities													**(122)**	92	**(186)**	(204)
Foreign exchange loss (gain)													**211**	(90)	**107**	(53)
Total non-segmented expenses													**2**	149	**90**	165
Earnings before taxes													**1,154**	803	**2,635**	2,940
Current income tax expense													**165**	173	**561**	613
Deferred income tax expense													**153**	34	**263**	345
Net earnings													**836**	596	**1,811**	1,982

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2011			Sep 30, 2010		
	Net expenditures	**Non cash and fair value changes[2]**	**Capitalized costs**	Net expenditures	Non cash and fair value changes[2]	Capitalized costs
Exploration and evaluation						
Exploration and Production						
North America	**$ 199**	**$ (225)**	**$ (26)**	$ 149	$ (195)	$ (46)
North Sea	**–**	**(4)**	**(4)**	14	(1)	13
Offshore Africa	**1**	**–**	**1**	–	–	–
	$ 200	**$ (229)**	**$ (29)**	$ 163	$ (196)	$ (33)
Property, plant and equipment						
Exploration and Production						
North America	**$ 2,991**	**$ 255**	**$ 3,246**	$ 2,620	$ 212	$ 2,832
North Sea	**156**	**4**	**160**	97	5	102
Offshore Africa	**50**	**(29)**	**21**	206	–	206
	3,197	**230**	**3,427**	2,923	217	3,140
Oil Sands Mining and Upgrading[3][4]	**940**	**(406)**	**534**	367	5	372
Midstream	**5**	**–**	**5**	4	–	4
Head office	**16**	**–**	**16**	13	(11)	2
	$ 4,158	**$ (176)**	**$ 3,982**	$ 3,307	$ 211	$ 3,518

(1) This table provides a reconciliation of capitalized costs and does not include the impact of accumulated depletion and depreciation.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

(3) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest, share-based compensation, and the impact of intersegment eliminations.

(4) During the first quarter of 2011 the Company derecognized certain property, plant and equipment related to the coker fire incident at Horizon in the amount of $411 million. This amount has been included in non-cash and fair value changes.

Segmented Assets

	Total assets	
	Sep 30 2011	Dec 31 2010
Exploration and Production		
North America	**$ 26,901**	$ 25,486
North Sea	**1,849**	1,759
Offshore Africa	**1,130**	1,263
Other	**47**	15
Oil Sands Mining and Upgrading	**15,142**	14,026
Midstream	**333**	338
Head office	**73**	67
	$ 45,475	$ 42,954

18. TRANSITION TO IFRS

The effect of the Company's transition to IFRS, described in Note 1, is summarized below:

(i) Transition elections

The Company has applied the following transition exceptions and exemptions to full retrospective application of IFRS as described below:

	Note
Deemed cost of property, plant and equipment	(a)
Leases	(b)
Share-based compensation	(c)
Borrowing costs	(d)
Asset retirement obligations	(e)
Cumulative translation adjustment	(f)
Business combinations	(g)

(ii) Transition adjustments

The Company has recorded the following transition adjustments upon adoption of IFRS:

	Note
Risk management	(h)
Petroleum Revenue Tax	(i)
UK deferred income tax liabilities	(j)
Reclassification of current portion of deferred income tax	(k)
Horizon major maintenance costs	(l)
Long-term debt	(m)

Reconciliations of the Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)		Dec 31, 2010			Sep 30, 2010			Jan 1, 2010		
	Note	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $
ASSETS										
Current assets										
Cash and cash equivalents		22	–	22	27	–	27	13	–	13
Accounts receivable		1,481	–	1,481	1,246	–	1,246	1,148	–	1,148
Inventory	(a)	481	(4)	477	419	(8)	411	438	–	438
Prepaids and other		129	–	129	163	–	163	146	–	146
Deferred income tax assets	(k)	59	(59)	–	5	(5)	–	146	(146)	–
		2,172	(63)	2,109	1,860	(13)	1,847	1,891	(146)	1,745
Exploration and evaluation assets	(a)	–	2,402	2,402	–	2,259	2,259	–	2,293	2,293
Property, plant and equipment	(a)(c)(e)(l)	40,472	(2,043)	38,429	40,035	(2,154)	37,881	39,115	(2,097)	37,018
Other long-term assets		25	(11)	14	30	(12)	18	18	(12)	6
		42,669	285	42,954	41,925	80	42,005	41,024	38	41,062
LIABILITIES										
Current liabilities										
Accounts payable		274	–	274	274	–	274	240	–	240
Accrued liabilities		1,733	2	1,735	1,513	–	1,513	1,428	2	1,430
Current income tax liabilities		430	–	430	378	–	378	94	–	94
Deferred income tax liabilities	(k)	–	–	–	–	–	–	–	–	–
Current portion of long-term debt	(m)	–	397	397	–	811	811	–	400	400
Current portion of other long-term liabilities	(c)	719	151	870	210	166	376	643	211	854
		3,156	550	3,706	2,375	977	3,352	2,405	613	3,018
Long-term debt	(h)(m)	8,499	(411)	8,088	8,490	(820)	7,670	9,658	(399)	9,259
Other long-term liabilities	(c)(e)(h)	2,130	874	3,004	1,817	681	2,498	1,848	637	2,485
Deferred income tax liabilities	(i)(j)(k)	7,899	(111)	7,788	7,823	(50)	7,773	7,687	(225)	7,462
		21,684	902	22,586	20,505	788	21,293	21,598	626	22,224
SHAREHOLDERS' EQUITY										
Share capital		3,147	–	3,147	3,015	–	3,015	2,834	–	2,834
Retained earnings		18,005	(793)	17,212	18,502	(900)	17,602	16,696	(769)	15,927
Accumulated other comprehensive (loss) income	(f)(h)	(167)	176	9	(97)	192	95	(104)	181	77
		20,985	(617)	20,368	21,420	(708)	20,712	19,426	(588)	18,838
		42,669	285	42,954	41,925	80	42,005	41,024	38	41,062

Reconciliations of the Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)		Year ended Dec 31, 2010			Three months ended Sep 30, 2010			Nine months ended Sep 30, 2010		
	Note	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $
Product sales		14,322	–	14,322	3,341	–	3,341	10,535	–	10,535
Less: royalties		(1,421)	–	(1,421)	(313)	–	(313)	(990)	–	(990)
Revenue		12,901	–	12,901	3,028	–	3,028	9,545	–	9,545
Expenses										
Production	(a)	3,447	2	3,449	867	–	867	2,573	–	2,573
Transportation and blending		1,783	–	1,783	350	–	350	1,323	–	1,323
Depletion, depreciation and amortization	(a)(e)(l)	4,036	84	4,120	851	47	898	2,458	116	2,574
Administration	(a)	210	1	211	43	–	43	157	–	157
Share-based compensation	(c)	294	(91)	203	18	(23)	(5)	(42)	(21)	(63)
Asset retirement obligation accretion	(e)	107	16	123	28	3	31	80	12	92
Interest and other financing costs	(h)	449	(1)	448	109	–	109	329	(1)	328
Risk management activities	(h)	(121)	(13)	(134)	22	–	22	(320)	(6)	(326)
Foreign exchange (gain) loss	(j)	(182)	19	(163)	(64)	(26)	(90)	(68)	15	(53)
		10,023	17	10,040	2,224	1	2,225	6,490	115	6,605
Earnings before taxes		2,878	(17)	2,861	804	(1)	803	3,055	(115)	2,940
Taxes other than income tax		119	(119)	–	21	(21)	–	94	(94)	–
Current income tax expense		698	91	789	163	10	173	542	71	613
Deferred income tax expense	(i)(j)	364	35	399	40	(6)	34	306	39	345
Net earnings		1,697	(24)	1,673	580	16	596	2,113	(131)	1,982
Net earnings per common share										
Basic		1.56	(0.02)	1.54	0.53	0.01	0.54	1.94	(0.12)	1.82
Diluted		1.56	(0.03)	1.53	0.53	0.01	0.54	1.94	(0.13)	1.81

Reconciliations of the Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)		Year ended Dec 31, 2010			Three months ended Sep 30, 2010			Nine months ended Sep 30, 2010		
	Note	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $
Net earnings		1,697	(24)	1,673	580	16	596	2,113	(131)	1,982
Net change in derivative financial instruments designated as cash flow hedges										
Unrealized (loss) income during the period	(h)	(35)	(18)	(53)	(79)	(10)	(89)	17	1	18
Income tax		11	2	13	17	1	18	5	–	5
Unrealized (loss) income during the period, net of tax		(24)	(16)	(40)	(62)	(9)	(71)	22	1	23
Reclassification to net earnings		(5)	–	(5)	(1)	–	(1)	(5)	–	(5)
Income tax		1	–	1	–	–	–	1	–	1
Reclassification to net earnings, net of taxes		(4)	–	(4)	(1)	–	(1)	(4)	–	(4)
		(28)	(16)	(44)	(63)	(9)	(72)	18	1	19
Foreign currency translation adjustment										
Translation of net investment		(35)	11	(24)	(21)	19	(2)	(11)	10	(1)
Other comprehensive (loss) income, net of taxes		(63)	(5)	(68)	(84)	10	(74)	7	11	18
Comprehensive income		1,634	(29)	1,605	496	26	522	2,120	(120)	2,000

Notes:

(a) Deemed cost of property, plant and equipment

In accordance with IFRS transitional provisions, the Company elected to use the deemed cost of property, plant and equipment for its exploration and production assets, which allowed the Company to measure its exploration and evaluation assets at the amounts capitalized under Canadian GAAP at the date of transition to IFRS. Additionally, under the transitional provision, the Company elected to allocate the carrying amount of property, plant and equipment in the development or production phases under Canadian GAAP to IFRS applicable assets pro rata using reserve values as at January 1, 2010, subject to impairment tests. The impairment tests compared the carrying amount of the assets to their recoverable amounts. The recoverable amount is the higher of fair value less costs to sell or value in use. The impairment tests conducted by the Company resulted in a reduction to the carrying amounts of Offshore Africa property, plant and equipment at the date of transition of $62 million. At January 1, 2010, retained earnings were reduced by $53 million, net of income taxes of $9 million.

For the year ended December 31, 2010, net earnings decreased by $119 million, net of taxes of $27 million, to reflect the impact of higher depletion charges, partially offset by $78 million, net of taxes of $11 million, to reflect the impact of a lower impairment charge on the Gabon CGU. For the nine months ended September 30, 2010, net earnings decreased by $78 million, net of taxes of $16 million, to reflect the impact of higher depletion charges.

(b) Leases

The Company elected under IFRS 1 not to reassess whether an arrangement contains a lease under IFRIC 4 for contracts that were assessed under Canadian GAAP. Arrangements entered into before the effective date of Canadian GAAP EIC 150 that have not subsequently been assessed under EIC 150, were assessed under IFRIC 4, and no additional leases were identified.

(c) Share-based compensation

The Company has granted share-based compensation that may be settled in either cash or shares at the holder's option to all employees. The Company accounted for these share-based payment arrangements by reference to their intrinsic value under Canadian GAAP. Under IFRS the related liability has been adjusted to reflect the fair value of the outstanding share-based compensation. The Company elected to use the IFRS 1 exemption to not retrospectively restate share-based payment transactions that were settled before the date of transition to IFRS. This adjustment increased the share-based compensation liability by $230 million (December 31, 2010 – $147 million; September 30, 2010 – $219 million). Included in this amount was $11 million (December 31, 2010 – $19 million; September 30, 2010 – $21 million) capitalized to Oil Sands Mining and Upgrading. At January 1, 2010, retained earnings were reduced by $170 million, net of income taxes of $49 million.

For the year ended December 31, 2010, net earnings increased by $91 million and for the nine months ended September 30, 2010, net earnings increased by $21 million to reflect differences in share-based compensation expense. In addition, during the nine months ended September 30, 2010, deferred income tax expense included an additional charge of $49 million related to the change to the taxation of stock options surrendered by employees for cash.

(d) Borrowing costs

Under Canadian GAAP the Company was not required to capitalize all borrowing costs in respect of constructed assets. At the date of transition, the Company elected to capitalize borrowing costs in respect of all qualifying assets effective January 1, 2010.

(e) Asset retirement obligations

In accordance with IFRS transitional provisions for assets described in (a) above, the Company remeasured the liability associated with asset retirement obligation activities for the North America, North Sea and Offshore Africa Exploration and Production segments at the date of transition, resulting in an increase in asset retirement obligations of $338 million. At January 1, 2010, retained earnings were reduced by $210 million, net of income taxes of $128 million.

In addition, the Company remeasured the liability related to asset retirement obligation activities in the Oil Sands Mining and Upgrading segment at the date of transition. These assets were not subject to the election in (a) above and accordingly, the difference in the liability between Canadian GAAP and IFRS of $266 million was recognized in property, plant and equipment in accordance with IFRS transitional provisions. Additional accumulated depletion of $2 million was recognized in retained earnings.

The difference between Canadian GAAP and IFRS asset retirement obligations related primarily to discount rates.

As at December 31, 2010, an additional liability of $234 million was recognized in property, plant and equipment. For the year ended December 31, 2010, net earnings decreased by $15 million, net of taxes of $6 million, and for the nine months ended September 30, 2010, net earnings decreased by $10 million, net of taxes of $5 million, to reflect the impact of higher depletion and accretion charges.

(f) Cumulative translation adjustment

In accordance with IFRS transitional provisions, the Company elected to reset the cumulative translation adjustment account, which includes gains and losses arising from the translation of foreign operations, to $nil at the date of transition to IFRS. Accordingly, accumulated other comprehensive income increased by $180 million and retained earnings were reduced by $180 million.

(g) Business combinations

In accordance with IFRS transitional provisions, the Company elected to apply IFRS relating to business combinations prospectively from January 1, 2010. As such, Canadian GAAP balances relating to business combinations entered into before that date have been carried forward without adjustment.

(h) Risk management

Under Canadian GAAP, the Company was required to adjust the carrying amount of the liability for risk management derivative financial instruments by the Company's own credit risk. Under IFRS, this adjustment is not required. The reversal of the credit risk adjustment for IFRS on January 1, 2010 resulted in an increase in the carrying amount of the risk management liability of $16 million (December 31, 2010 – increase of $34 million; September 30, 2010 – increase of $16 million) and an increase in accumulated comprehensive income of $1 million (December 31, 2010 – decrease of $15 million; September 30, 2010 – increase of $3 million). At January 1, 2010, retained earnings were reduced by $13 million, net of income taxes of $5 million. Further, differences in applying fair value hedge accounting between Canadian GAAP and IFRS resulted in an increase to the carrying value of hedged long-term debt by $1 million (December 31, 2010 – decrease of $14 million; September 30, 2010 – decrease of $9 million).

For the year ended December 31, 2010, net earnings increased by $10 million, net of income taxes of $4 million and other comprehensive income decreased by $16 million, net of income taxes of $2 million. For the nine months ended September 30, 2010, net earnings increased by $4 million, net of income taxes of $3 million, and other comprehensive income increased by $1 million, net of income taxes of $ nil.

(i) Petroleum Revenue Tax

Under Canadian GAAP, the Company calculated its deferred PRT liability using the life-of-field method. Under IFRS, the Company calculates its deferred PRT liability based on temporary differences arising between the tax base of assets and liabilities of PRT paying fields and their carrying amounts in the consolidated balance sheets. As a result of this adjustment, the deferred income tax liability was increased by $116 million ($58 million after-tax) at January 1, 2010 (December 31, 2010 – $80 million, $40 million after-tax; September 30, 2010 – $96 million, $48 million after-tax). At January 1, 2010, retained earnings were reduced by $58 million.

For the year ended December 31, 2010, net earnings increased by $18 million, net of taxes of $18 million and for the nine months ended September 30, 2010, net earnings increased by $10 million, net of taxes of $10 million, to reflect the impact of lower PRT charges.

(j) UK deferred income tax liabilities

Under Canadian GAAP, the Company calculated the future income tax liabilities of its UK subsidiaries in UK pounds sterling, and converted the resultant liability to its US dollar functional currency. Under IFRS, the Company calculates its UK-based deferred income tax liabilities directly in the functional US dollar currency. This adjustment resulted in an increase in the deferred income tax liability of $61 million at January 1, 2010 (December 31, 2010 – $80 million; September 30, 2010 – $76 million). At January 1, 2010, retained earnings were reduced by $61 million.

For the year ended December 31, 2010, net earnings decreased by $19 million, and for the nine months ended September 30, 2010, net earnings decreased by $15 million.

(k) Reclassification of current portion of deferred income tax

Under Canadian GAAP, deferred income taxes relating to current assets or current liabilities were classified as current. Under IFRS, deferred income tax balances are classified as long-term, irrespective of the classification of the assets or liabilities to which the deferred income tax relates or the expected timing of reversal. Accordingly, current deferred income tax assets reported under Canadian GAAP of $146 million at January 1, 2010 (December 31, 2010 – current deferred income tax assets of $59 million; September 30, 2010 – current deferred income tax assets of $5 million) have been reclassified as non-current under IFRS.

(l) Horizon major maintenance costs

Under Canadian GAAP, the Company would have deferred and amortized major maintenance turnaround costs on a straight-line basis over the period to the next scheduled major maintenance turnaround. Under IFRS, the Company has identified capitalized components of the original cost of an asset, which have a shorter useful life, and has amortized the costs of these components over the period to the next turnaround. At January 1, 2010, retained earnings decreased by $14 million, net of taxes of $5 million.

For the year ended December 31, 2010, net earnings decreased by $19 million, net of taxes of $6 million, and for the nine months ended September 30, 2010, net earnings decreased by $14 million, net of taxes of $5 million, to reflect the impact of higher depletion charges.

(m) Long-term debt

Under Canadian GAAP, debt maturities within one year of the date of the balance sheet were classified as non-current on the basis that the Company had the intent and ability to refinance these obligations with its existing long-term credit facilities. Under IFRS, as the long-term debt maturing within one year was not payable to the same counterparty lenders as the long-term debt facility, $400 million was reclassified to current at January 1, 2010 (December 31, 2010 – $397 million; September 30, 2010 – $811 million).

Deferred income tax liabilities have been adjusted to give effect to adjustments as follows:

	Note	Dec 31 2010	Sep 30 2010	Jan 1 2010
Deferred income tax assets as reported under Canadian GAAP		$ 59	$ 5	$ 146
Deferred income tax liabilities as reported under Canadian GAAP		(7,899)	(7,823)	(7,687)
Deferred income tax, net		(7,840)	(7,818)	(7,541)
IFRS adjustments				
Deemed cost of property, plant and equipment	(a)	25	25	9
Share-based compensation	(c)	–	–	49
Asset retirement obligations	(e)	134	133	128
Risk management	(h)	3	2	5
PRT	(i)	(40)	(48)	(58)
UK deferred income tax liabilities	(j)	(80)	(76)	(61)
Horizon maintenance costs	(l)	11	10	5
Foreign exchange and other		(1)	(1)	2
Deferred income tax liabilities as reported under IFRS		$ (7,788)	$ (7,773)	$ (7,462)

The following is a summary of transition adjustments, net of tax, to the Company's accumulated other comprehensive income from Canadian GAAP to IFRS:

	Note	Dec 31 2010	Sep 30 2010	Jan 1 2010
Accumulated other comprehensive income as reported under Canadian GAAP		$ (167)	$ (97)	$ (104)
IFRS adjustments				
Cumulative translation adjustment on transition	(f)	180	180	180
Risk management	(h)	(15)	2	1
Translation of net investment		11	10	–
Accumulated other comprehensive income as reported under IFRS		$ 9	$ 95	$ 77

The following is a summary of transition adjustments, net of tax, to the Company's retained earnings from Canadian GAAP to IFRS:

	Note	Dec 31 2010	Sep 30 2010	Jan 1 2010
Retained earnings as reported under Canadian GAAP		$ 18,005	$ 18,502	$ 16,696
IFRS adjustments				
Deemed cost of property, plant and equipment	(a)	(94)	(131)	(53)
Share-based compensation	(c)	(128)	(198)	(170)
Asset retirement obligations	(e)	(227)	(222)	(212)
Cumulative translation adjustment	(f)	(180)	(180)	(180)
Risk management	(h)	(3)	(9)	(13)
PRT	(i)	(40)	(48)	(58)
UK deferred income tax liabilities	(j)	(80)	(76)	(61)
Horizon maintenance costs	(l)	(33)	(28)	(14)
Other		(8)	(8)	(8)
Retained earnings as reported under IFRS		$ 17,212	$ 17,602	$ 15,927

Adjustments to the statements of cash flows

The transition from Canadian GAAP to IFRS had no significant impact on cash flows generated by the Company.

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 October 2011. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended September 30, 2011:

Interest coverage (times)	
Net earnings [(1)]	6.2x
Cash flow from operations [(2)]	15.3x

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

(2) Cash flow from operations plus current income taxes and interest expense excluding current PRT 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 Daylight Time, 11:00 a.m. Eastern Daylight Time on Thursday, November 3, 2011. The North American conference call number is 1-800-952-6845 and the outside North American conference call number is 001-416-695-7848. 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 Daylight Time, Friday, November 11, 2011. To access the postview in North America, dial 1-800-408-3053. Those outside of North America, dial 001-905-694-9451. The passcode to use is 7148126.

WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com.

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