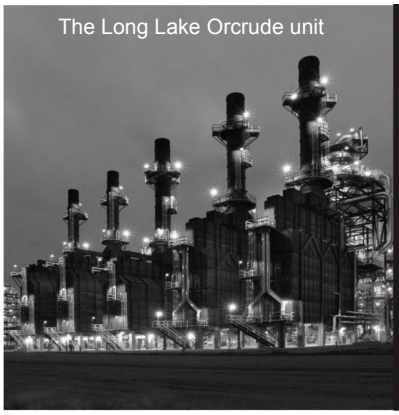

nexen

Q1 INTERIM REPORT

For three months ended March 31, 2010

Nexen Announces Ongoing Execution Success and First Quarter Results

(Cdn$ millions)	Three Months Ended March 31 2010	Three Months Ended March 31 2009	Three Months Ended December 31 2009
Production before Royalties (mboe/d)	252	252	265
Production after Royalties (mboe/d)	221	225	235
Net Sales	1,501	1,048	1,550
Cash Flow from Operations[1]	538	557	836
Per Common Share ($/share)	1.03	1.07	1.60
Net Income (Loss)	185	135	259
Per Common Share ($/share)	0.35	0.26	0.50
Capital Expenditures, including Acquisitions[2]	568	1,516	645
Net Debt[3]	5,057	5,737	5,551
Common Shares Outstanding (millions of shares)	524.0	520.8	522.9

1 Cash flow from operations is defined as cash flow from operating activities before changes in non-cash working capital and other.
2 Includes oil and gas development, exploration, and expenditures for other property, plant and equipment and the $735 million acquisition of an additional 15% working interest in our Long Lake project.
3 Defined as long-term debt and short-term borrowings less cash and cash equivalents.

We continue to successfully execute on our three strategies. On the conventional side, we had a major oil discovery at Appomattox in the Eastern Gulf of Mexico, adding to our recent exploration successes at Golden Eagle in the North Sea, and Owowo, offshore West Africa. At Long Lake, we are steadily climbing the growth curve, as our bitumen production volumes increase. And in the Horn River, we finished drilling our eight-well shale gas program and realized further cost improvements. Quarterly cash flow from operations was $538 million and net income was $185 million. With strong crude prices and 85% of our production weighted to oil, we benefit from increasing prices. Cash flow was reduced by operating results at Long Lake and in marketing.

First quarter production averaged 252,000 boe/d (221,000 boe/d after royalties) as volumes were temporarily impacted by downtime at Buzzard, Ettrick and Syncrude. At Buzzard, volumes were lower as repairs were made to the separator unit. At Ettrick, production was impacted by commissioning activities and a two week shut-in for rig moves relating to drilling and completion activities in the area. Syncrude had a turnaround of its LC Finer.

At Long Lake, bitumen volumes have been consistently growing since the completion of the turnaround last fall. We are currently producing around 25,000 bbls/d gross and are seeing production increases from new wells and from the optimization of mature producers. This represents an 80% increase over average pre-turnaround rates.

In the Eastern Gulf of Mexico, we made a significant oil discovery at Appomattox. Initial estimates support development of a regional hub and we are actively appraising results. Elsewhere in the deep-water, we completed drilling an appraisal well at Knotty Head and are currently evaluating results and development choices.

In the Horn River, we have drilled an eight-well shale gas program and plan to complete these wells in the latter half of the year with 18 fracs per well. First production is expected before year-end, ramping up to 50 mmcf/d.

On the disposition front, we have successfully sold our European gas and power marketing business and have substantially completed negotiations for the sale of our North American natural gas business.

The Board of Directors has declared the regular quarterly dividend of $0.05 per common share payable July 1, 2010, to shareholders of record on June 10, 2010.

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A)

The following should be read in conjunction with the Unaudited Consolidated Financial Statements included in this report. The Unaudited Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of the significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 20 to the Unaudited Consolidated Financial Statements. The date of this discussion is April 26, 2010.

Unless otherwise noted, tabular amounts are in millions of Canadian dollars. The discussion and analysis of our oil and gas activities with respect to oil and gas volumes, reserves and related performance measures is presented on a working-interest, before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, information on a net, after-royalties basis is also presented.

Note: Canadian investors should read the Special Note to Canadian Investors on page 97 of our 2009 Form 10-K which highlights differences between our reserves estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

We make estimates and assumptions that affect the reported amounts of our assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Unaudited Consolidated Financial Statements and our revenues and expenses during the reported period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes, fair values of derivative contract assets and liabilities and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

EXECUTIVE SUMMARY OF FIRST QUARTER RESULTS

	Three Months Ended March 31	
(Cdn$ millions, except as indicated)	**2010**	**2009**
Production before Royalties (mboe/d)	252	252
Production after Royalties (mboe/d)	221	225
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	70.16	47.56
Cash Flow from Operating Activities	798	789
Net Income Attributable to Nexen Inc.	185	135
Earnings per Common Share, Basic ($/share)	0.35	0.26
Capital Investment	556	747
Acquisition of Additional Interest in Long Lake	–	757
Net Debt [1]	5,057	5,737

[1] Net debt is a non-GAAP measure and is defined as long-term debt and short-term borrowings less cash and cash equivalents.

Production for the quarter was consistent with last year. Production increases at Long Lake, the Gulf of Mexico and at Ettrick and Telford in the UK North Sea were offset by natural declines at Yemen and maintenance downtime at Buzzard for repairs to the separator unit. Our realized average oil and gas price averaged $70.16/boe for the quarter, 48% higher than last year as a result of stronger benchmark commodity prices. The stronger Canadian dollar relative to the US dollar reduced the benefit of the higher commodity prices. The combined impact of higher prices and steady production, offset by lower energy marketing cash flow, resulted in a 37% increase in net income.

At our Long Lake oil sands project, we are steadily growing bitumen production volumes each month as we increase steam volumes. We expect Long Lake to make positive cash flow contributions later this year as our bitumen volumes grow.

We incurred approximately 20% of our 2010 capital budget to date. Our expenditures have focused on our major developments at Long Lake and Usan, offshore West Africa, exploration in the Gulf of Mexico and the North Sea, and advancing our shale gas project in north-east British Columbia.

During the quarter, we made a significant oil discovery at Appomattox in Eastern Gulf of Mexico where we drilled an exploratory well and two appraisal sidetracks. Appomattox is the third discovery in the area following earlier discoveries at Shiloh and Vicksburg. Additional exploration and appraisal wells for Appomattox are planned for later this year.

Our financial position remains strong with available liquidity of approximately $3.6 billion. This liquidity includes cash on hand of $2 billion and undrawn lines of credit of approximately $1.6 billion. We have no significant debt maturities until 2012 and the average term-to-maturity of our long-term debt is approximately 17 years. We believe our significant liquidity, combined with strong operating cash netbacks, provides us with the financial flexibility to carry out our investment programs.

CAPITAL INVESTMENT

Our strategy is to build a sustainable energy company focused in three areas: conventional exploration and development, oil sands, and unconventional gas. We are committed to growing long-term value for our shareholders responsibly and are advancing our plans to achieve this as described below.

We are currently investing primarily in:

- ramping up Long Lake safely and reliably;
- progressing construction of our Usan project and continuing to explore our acreage, offshore Nigeria;
- advancing development plans for our Golden Eagle area in the UK North Sea;
- appraising exploration successes at Appomattox and Knotty Head in the Gulf of Mexico;
- targeting a number of exploration prospects, primarily in the North Sea and Gulf of Mexico; and
- advancing our Horn River shale gas play in north-east British Columbia.

Details of our capital programs are set out below:

Three Months Ended March 31, 2010

	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
United Kingdom	22	–	41	66	129
Canada	–	–	68	6	74
Synthetic (mainly Long Lake)	–	15	–	49	64
Syncrude	–	–	–	19	19
United States	–	–	49	15	64
Yemen	–	–	–	10	10
Nigeria	91	–	1	–	92
Other Countries	–	–	40	–	40
	113	15	199	165	492
Chemicals	–	–	–	49	49
Energy Marketing, Corporate and Other	–	–	–	15	15
Total Capital	113	15	199	229	556
As a % of Total Capital	20%	3%	36%	41%	100%

United Kingdom – North Sea

The Golden Eagle area has emerged as a significant development opportunity for us. We are in the process of completing the acquisition of additional land in the area and plan to drill an exploration well here mid-year. Golden Eagle area development supports standalone facilities and is economic with oil prices significantly lower than they are currently. We are assessing development options for the area and will select an appropriate configuration prior to sanctioning in 2011. We have a 34% interest in both Golden Eagle and Hobby, a 46% interest in Pink, and operate all three.

West of the Shetland Islands, we are finalizing plans to drill the North Uist prospect. We have a 35% working interest here and expect to drill the well in the second half of 2010. This prospect has a target size much larger than typical North Sea targets. BP is the operator with a 45% working interest.

Canada – Horn River Shale Gas

We have finished drilling our eight-well program and continue to make significant progress on lowering costs and gaining access to the shale reservoir on our substantial Horn River shale gas position in north-east British Columbia. We plan to complete these wells in the second half of the year with 18 fracs per well. First production from these wells is expected before year end, ramping up to 50 mmcf/d.

Substantial cost savings and productivity improvements were realized with this drilling program and our average drilling days per well were under 25 days. We currently expect that with an 18 well program, we could reduce our all-in costs even further to under $0.6 million per frac. Our production results to date, together with those of our competitors, indicate that recovery factors should be higher than our estimate of 20%. Additional production history will determine recovery factors.

Synthetic

Since the completion of the turnaround last fall, bitumen volumes have been consistently growing. Long Lake's gross bitumen production has grown from 14,000 bbls/d in the fourth quarter of 2009 to 19,000 bbls/d in the first quarter of 2010. In March, gross bitumen production averaged 22,000 bbls/d. We are currently producing approximately 25,000 bbls/d and are seeing production increases from both new wells and from optimization of mature producers. This represents an 80% increase over average pre-turnaround rates.

Production growth reflects significant improvement in steam reliability since the turnaround and steam rates are at all-time highs of about 140,000 bbls/d and increasing. This represents a 100% increase over pre-turnaround rates. As a result, we are injecting more steam into more wells than ever before with 64 well pairs now on production and steam circulating in an additional 15 pairs. These circulating wells will be converted to production over the next few months.

Our all-in steam-to-oil ratio (SOR) is between 5 and 6 but this includes steam to wells that are still in the steam circulation stage and wells early in their growth cycle. As our circulating wells start producing bitumen, we expect to see an increase in bitumen production rates with a corresponding decrease in SOR. The SOR of our producing wells is approximately 5, and includes well pairs recently converted to production that are in the early stages of ramp up. We continue to expect a long term SOR of 3.0 over the life of the project.

The upgrader facility is also performing consistently. Since the turnaround, the upgrader has experienced 90% uptime, compared to 50% before and is producing high quality premium synthetic crude (PSC™). For the quarter, our realized price for Long Lake PSC™ averaged over $81/bbl. The gasification process is working, creating a low-cost fuel source which reduces our need to purchase natural gas for operations and will generate a significant margin advantage over our peers, even at current low gas prices.

United States – Gulf of Mexico

During the quarter, we made a significant discovery in the Eastern Gulf of Mexico at Appomattox, located in Mississippi Canyon blocks 391 and 392. Drilling activities resulted in an oil discovery with excellent reservoir quality, following an exploration well and two appraisal sidetracks. The discovery well, located in 7,217 feet of water, was drilled to a depth of 25,077 feet true vertical depth. An appraisal sidetrack was drilled to approximately 25,950 feet true vertical depth. The second sidetrack was undertaken to further delineate the discovery. Well results have exceeded our pre-drill expectations.

Appomattox is the third discovery in the area following earlier discoveries at Shiloh and Vicksburg. Additional appraisal wells for Appomattox are planned for later in the year and we are investigating development options for Appomattox and Vicksburg, located six miles east. We have a 25% interest in Vicksburg and a 20% interest in Appomattox and Shiloh. Shell Offshore Inc. operates all three discoveries.

Elsewhere in the deep water, we completed drilling an appraisal well at Knotty Head and are currently evaluating results and possible development choices. Drilling operations with our new deep-water rig exceeded expectations. We completed the well in approximately 15% less time than expected and 20% below planned cost. We are continuing our efforts to unitize our lands with adjacent acreage. We are operator of Knotty Head with a 25% working interest. A second deep-water drilling rig is expected to arrive later this year which will allow us to start drilling our other identified prospects.

Offshore West Africa

Development of the Usan field, offshore West Africa, is progressing well with first production expected in 2012. The development includes a floating production and storage (FPSO) vessel with the ability to process 180,000

bbls/d (36,000 bbls/d net to us) and store up to two million barrels of oil. We have a 20% interest in exploration and development on this block and Total E&P Nigeria Limited is the operator.

We continue to explore offshore West Africa and previously announced a successful exploration well at Owowo in the southern portion of Oil Prospecting License (OPL) 223. Other exploration prospects are under evaluation for drilling.

FINANCIAL RESULTS

Change in Net Income

	2010 vs 2009
Net Income at March 31, 2009	135
Favorable (unfavorable) variances[1]:	
Realized Commodity Prices	
Crude Oil	410
Natural Gas	1
Total Price Variance	411
Production Volumes, After Royalties	
Crude Oil	(15)
Natural Gas	34
Changes in Crude Oil Inventory For Sale	38
Total Volume Variance	57
Oil and Gas Operating Expense	(112)
Oil and Gas Depreciation, Depletion, Amortization and Impairment	19
Exploration Expense	(40)
Energy Marketing Revenue, Net	(151)
Chemicals Contribution	4
General and Administrative Expense [2]	(18)
Interest Expense	(12)
Current Income Taxes	(141)
Future Income Taxes	13
Other	20
Net Income at March 31, 2010	185

[1] All amounts are presented before provision for income taxes.
[2] Includes stock-based compensation expense.

Significant variances in net income are explained further in the following sections.

OIL & GAS

Production

	Three Months Ended March 31			
	2010		**2009**	
	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties
Crude Oil and Liquids (mbbls/d)				
United Kingdom	105.6	105.6	103.8	103.8
Canada	14.2	11.0	15.5	12.3
Long Lake Bitumen	12.1	11.3	8.1	8.1
Syncrude	19.5	17.8	19.8	19.6
United States	9.8	8.9	10.4	9.5
Yemen	42.8	23.1	54.5	35.7
Other Countries	2.3	2.1	5.5	5.1
	206.3	179.8	217.6	194.1
Natural Gas (mmcf/d)				
United Kingdom	40	40	18	18
Canada	133	121	137	122
United States	101	88	50	45
	274	249	205	185
Total Production (mboe/d)	252	221	252	225

[1] We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

Higher sales volumes increased net income for the quarter by $57 million

Production before royalties remained consistent with the same period in 2009. Production increases included i) restoring Gulf of Mexico gas production which was shut in due to Hurricane Ike and new production at Longhorn; ii) new volumes from Ettrick and Telford in the UK North Sea; and iii) ramping up Long Lake bitumen production. These increases were offset by i) natural declines in Yemen; ii) reduced working interest in Colombia; iii) lower production in Canada; and iv) temporary downtime at Buzzard. Compared to the fourth quarter of 2009, production before royalties decreased 5% as a result of downtime at Buzzard and Ettrick in the UK North Sea and an advanced turnaround at Syncrude. This was partially offset by increased production at Long Lake and the ramp up of Longhorn in the Gulf of Mexico.

The following table summarizes our production volume changes since last quarter:

(mboe/d)	Before Royalties	After Royalties
Production, fourth quarter 2009	265	235
Production changes:		
Long Lake Bitumen	3	2
United States	3	2
Canada	(1)	–
Yemen	(2)	(3)
Syncrude	(4)	(3)
United Kingdom	(12)	(12)
Production, first quarter 2010	252	221

Production volumes discussed in this section represent before-royalties volumes, net to our working interest.

UNITED KINGDOM

Production volumes in the UK North Sea averaged 112,300 boe/d in the quarter, 5% higher than the first quarter of 2009 but 10% lower than the previous quarter. The decrease from the previous quarter was primarily a result of downtime at Buzzard for repairs to the separator unit and drilling rig movement and commissioning activities at Ettrick which required a shut in of the FPSO vessel.

Buzzard production averaged 84,600 boe/d during the quarter, 2% below the previous quarter and 9% lower than the first quarter last year. Routine monitoring of equipment on the Buzzard platform during the quarter identified repairs that were required to the separator unit. The repair work lasted a week, during which time Buzzard produced at reduced rates of approximately 50,000 boe/d (gross). Production was subsequently restored to full capacity. Further activities are scheduled to permanently repair the separator unit. This work is timed to coincide with our planned two week shutdown to install the topsides of the fourth platform in the second quarter.

Production at Scott/Telford decreased 15% from the prior quarter to average 20,400 boe/d as a result of well intervention work at Scott and scheduled maintenance at Telford. Production has almost doubled compared to the first quarter of 2009 as a result of a successful step-out development well at Telford. This well was completed in the third quarter of 2009 and is tied back to our Scott platform. Production from our non-operated fields at Duart and Farragon averaged 2,300 boe/d for the quarter.

Production from our Ettrick field averaged 5,000 boe/d for the quarter as we continue to ramp up the facilities and safely commission all systems. Production was 55% lower than the previous quarter as a result of commissioning activities and a two week shut-in for rig movements relating to drilling and completion activities in the area. Production was shut in for two weeks as a result. Ettrick production has been restored, is currently producing at rates around 20,000 boe/d gross (16,000 boe/d net to us) and continues to ramp up.

CANADA

Production in Canada decreased 5% from the first quarter of 2009 and remained comparable with the fourth quarter. Heavy oil production has remained strong as we successfully implemented strategies to maximize recoveries from our existing wells while minimizing capital investment. CBM production was consistent quarter over quarter and averaged 48 mmcf/d.

We continue to invest in our shale gas project in the Dilly Creek area of the Horn River basin in north-east British Columbia. We currently have six wells on production and they are meeting expectations with respect to production and decline profiles. During the quarter, we finished drilling an eight-well program to further test the play. We plan to complete these wells in the second half of the year. First production is from these wells expected before year end, ramping up to 50 mmcf/d.

LONG LAKE

Since the completion of the turnaround last fall, bitumen volumes have been consistently growing. Long Lake's gross bitumen production has grown from 14,000 bbls/d in the fourth quarter of 2009 to 19,000 bbls/d in the first quarter of 2010. In March, gross bitumen production averaged 22,000 bbls/d. We are currently producing approximately 25,000 bbls/d and are seeing production increases from both new wells and from optimization of mature producers. This represents an 80% increase over average pre-turnaround rates. The table below shows gross bitumen production volumes since the turnaround. We have a 65% interest in Long Lake.

Month	Gross Bitumen Volumes (bbls/d)
October 2009	8,600
November 2009	15,200
December 2009	16,200
January 2010	16,300
February 2010	17,700
March 2010	21,900
April 2010 – Month to date	24,500

Production growth reflects significant improvement in steam reliability since the turnaround and steam rates are at all-time highs of about 140,000 bbls/d and increasing. This represents a 100% increase over pre-turnaround rates. As a result, we are injecting more steam into more wells than ever before with 64 well pairs now on production and steam circulating in an additional 15 pairs. These circulating wells will be converted to production over the next few months.

SYNCRUDE

Syncrude production averaged 19,500 boe/d for the quarter, down 18% from the previous quarter and marginally lower than the first quarter of 2009. Production volumes were reduced as a turnaround of the LC finer originally planned for the second quarter was advanced to January. The turnaround was completed in mid March and is now back to full rates. A coker turnaround is scheduled in the third quarter.

UNITED STATES

Production in the Gulf of Mexico averaged 26,600 boe/d, 42% higher than the same period last year. The increase in production primarily came from our non-operated Longhorn development, which averaged 8,900 boe/d for the quarter. Production during the first quarter of 2009 was reduced as several fields remained shut in as a result of Hurricane Ike. These fields resumed full production in the second quarter of 2009. These increases have been offset by natural declines primarily at Gunnison.

Production in the US increased 11% from the prior quarter. The impact of increases from ramping up production at Longhorn were partially offset by lower production at Mississippi Canyon 72 and Wrigley.

YEMEN

Yemen production decreased 5% from the previous quarter and 21% from the first quarter of 2009. The decline is consistent with our expectations as the field matures and from reduced development drilling. During the quarter at Masila, we drilled four development wells and plan to drill up to seven more development wells later this year. At Block 51, we recently obtained approval to drill, complete and tie-in five additional development wells in the remainder of 2010. Production declines in Yemen are expected to continue as we focus on maximizing recovery of the remaining reserves.

We are working with the Yemen government and our partners to potentially extend our production-sharing agreement beyond the current expiry date of December 2011. There is no assurance that this extension will be received.

OTHER COUNTRIES

Our share of production from the Guando field in Colombia averaged 2,300 boe/d for the quarter. While this was consistent with the previous quarter, it was 58% lower than the first quarter of 2009 as lower volumes reflect the reduced working interest of the Guando field, effective the second quarter of 2009, once we achieved pre-set production levels.

Commodity Prices

	Three Months Ended March 31	
	2010	**2009**
Crude Oil		
West Texas Intermediate (WTI) (US$/bbl)	78.71	43.08
Dated Brent (Brent) (US$/bbl)	76.23	44.40
Benchmark Differentials [1] (US$/bbl)		
Heavy Oil	9.25	9.17
Mars	2.97	(0.66)
Masila	1.62	0.05
Realized Prices from Producing Assets (Cdn$/bbl)		
United Kingdom	77.25	51.60
Canada	65.26	35.35
Long Lake Synthetic	81.04	–
Syncrude	83.55	55.48
United States	79.12	46.27
Yemen	80.39	52.30
Other Countries	78.88	41.68
Corporate Average (Cdn$/bbl)	78.00	50.41
Natural Gas		
New York Mercantile Exchange (US$/mmbtu)	5.04	4.48
AECO (Cdn$/mcf)	5.08	5.34
Realized Prices from Producing Assets (Cdn$/mcf)		
United Kingdom	4.81	5.50
Canada	5.02	4.75
United States	6.00	5.93
Corporate Average (Cdn$/mcf)	5.37	5.11
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	70.16	47.56
Average Foreign Exchange Rate – Canadian to US Dollar	0.9615	0.8028

[1] These differentials are a discount/(premium) to WTI.

Higher commodity prices increased quarterly net income by $411 million

Crude oil prices continued to strengthen during the quarter with WTI averaging US$78.71/bbl, an increase of 83% over the same period last year and 3% higher than the prior quarter. Dated Brent increased 72% and 2% when compared to the same periods, averaging US$76.23/bbl for the quarter. The impact of higher commodity prices was reduced somewhat as the Canadian dollar strengthened compared to the US dollar over the same period last year. Our realized oil price averaged $78.00/bbl, 55% higher than the first quarter of 2009 and 2% higher than the previous quarter.

Natural gas prices were higher as NYMEX averaged US$5.04/mmbtu, 13% higher than the first quarter of 2009 and 3% higher than the previous quarter. AECO averaged Cdn$5.08/mcf during the first quarter, 27% above the prior quarter. Compared to the same period last year, AECO decreased 5% as the Canadian dollar has strengthened. Our realized gas price averaged $5.37/mcf, 25% higher than the prior quarter and 5% higher than the first quarter of 2009.

The Canadian dollar strengthened considerably against the US dollar, compared to the same period last year. This reduced our net sales by approximately $260 million, as our realized crude oil and gas prices were $15.42/bbl and $1.06/mcf lower, respectively. However, our US-dollar denominated long-term debt, operating expenses and capital expenditures are lower when translated to Canadian dollar as a result of the weaker US dollar.

CRUDE OIL REFERENCE PRICES

Crude oil prices were 83% higher than the first quarter 2009. WTI traded above US$80/bbl for most of March, supported by positive economic news, strong Asian demand and cold weather.

Demand/supply fundamentals for crude oil improved from better-than-expected world economic growth. OPEC continues to have spare production capacity but oil demand is forecasted to reach record levels by year end. Demand growth is exceeding non-OPEC supply growth resulting in reduction to spare capacity. Continued strong demand growth from emerging markets has redirected supplies away from the Atlantic basin and reduced floating inventory levels. More recently, demand for WTI increased as Canadian synthetic crude oil production has been constrained due to outages.

World-wide economic indicators appear relatively strong but there are concerns over sovereign credit risks, global fiscal imbalances and the timing and impact of the withdrawal of government fiscal and monetary stimuli. Most OECD countries have experienced GDP growth but it has been unbalanced with relatively strong growth in the US compared to minimal growth in Europe. China has seen strong growth but the government has taken actions to moderate this because of concerns about inflation and an overheating economy. Global economic growth remains a downside risk. A risk to commodity prices continues to be the lack of demand in developed markets.

Crude oil prices were supported late last year by the weakening US dollar. To date in 2010, the US dollar strengthened against the Euro and British Pound but this did not appear to impact crude oil prices. The US dollar is expected to weaken during 2010 which should continue to support higher crude oil prices.

The recent strength in crude oil prices has been partially attributed to geopolitical events such as concerns over Iran's nuclear enrichment program, the ongoing wars in Iraq and Afghanistan and threats of attacks to oil infrastructure in Nigeria. A much tighter supply/demand environment, and reduced spare capacity should increase price sensitivity to geopolitical events.

CRUDE OIL DIFFERENTIALS

The heavy oil differential continued to be narrower than historic levels due to declining heavy oil production and excess heavy refinery capacity. There was a slight widening of differentials in March primarily due to lower heavy fuel oil prices.

The Brent/WTI differential widened due to stronger WTI demand as a result of Canadian synthetic production outages and strong gasoline demand. Rising transatlantic freight rates also contributed to the wider differential.

The Masila price strengthened relative to Brent, reflecting strong demand from China and other Asian countries that are the primary buyers of Masila crude.

Excess global refining capacity, OPEC cuts in medium crude and declining heavy oil production also supported the Mars differential.

NATURAL GAS REFERENCE PRICES

NYMEX natural gas prices declined throughout the quarter as an early spring reduced heating demand and increased storage levels. Shale gas supply continues to grow despite lower prices. This new supply and the warmer spring weather are driving market concerns over higher storage levels despite the expected addition of new storage capacity in 2010. Some near-term support for demand includes industrial demand growth from a stronger economy, strong power demand due to an expected warmer summer than 2009, low US hydro power generation and higher coal-fired power costs. However, continuing weak gas prices are forecast as strong supply additions are expected from shale gas, tight gas and new LNG volumes imported from Russia and the Middle East.

Operating Expenses

(Cdn$/boe)	Three Months Ended March 31			
	2010		**2009**	
	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties
Conventional Oil and Gas	13.18	15.20	8.27	9.47
Syncrude	38.43	42.01	36.95	37.31
Average Oil and Gas	15.14	17.38	10.62	12.03

[1] Operating expenses per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

Higher operating expenses reduced quarterly net income by $112 million

Operating costs increased $112 million from the same period last year. The majority of the increase relates to costs associated with our Long Lake project. As of January 1, 2010, we ceased capitalizing our Long Lake operations as the facility was reliably operating as designed following the successful turnaround late last year. These costs are now included in operating expenses. The addition of these costs increased our per-unit average cost as bitumen production is still ramping up while costs at Long Lake are mostly fixed and do not vary significantly with production rates. We expect our average per-unit operating costs to decrease as bitumen production rates increase.

During the quarter, the strengthening Canadian dollar decreased our US dollar denominated operating costs, reducing our corporate average operating cost by $1.07/boe. Additionally, changes in production mix with natural declines in Canada and Yemen offset by increases in the North Sea and the Gulf of Mexico, decreased our corporate average by $0.11/boe.

In the UK North Sea, Buzzard operating costs were higher due to additional maintenance expense and higher transportation tariffs. These higher costs, combined with lower volumes due to temporary downtime, increased our corporate average operating cost by $0.61/boe. Elsewhere in the UK North Sea, operating costs increased our corporate average by $0.22/boe. At Ettrick, operating costs per barrel are higher than our corporate average because of the costs associated with the leased FPSO and from not being at full production rates yet. These higher average operating costs have been partially offset by lower average per-unit costs at Scott/Telford as a result of higher volumes.

In Yemen, we continue to incur costs to maintain existing well productivity to maximize reserve recoveries and slow the natural decline of the field. These costs, combined with production declines, increased our corporate average operating cost by $0.38/boe. In the US Gulf of Mexico, the effect of increased operating costs due to higher repair and maintenance expenditures was partially offset by higher volumes, increasing our corporate average operating cost by $0.04/boe.

Natural declines in Canada reduced production volumes, increasing our corporate average by $0.12/boe. At Syncrude, higher maintenance costs and lower production volumes associated with the turnaround of the LC finer increased our corporate average by $0.11/boe.

Depreciation, Depletion, Amortization and Impairment (DD&A)

	Three Months Ended March 31			
	2010		**2009**	
(Cdn$/boe)	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties
Conventional Oil and Gas	16.79	19.35	18.58	21.27
Syncrude	7.03	7.68	6.46	6.53
Average Oil and Gas	16.03	18.40	17.59	19.91

[1] DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

Lower oil and gas DD&A increased net income for the quarter by $19 million

Our average per-unit DD&A cost decreased $1.56/boe from the same period last year. The stronger Canadian dollar reduced our corporate average by $2.08/boe as depletion of our international and US assets is denominated in US dollars. This was partially offset by changes in our production mix which increased our average DD&A rate by $1.59/boe. The change in production mix was partially driven by lower production at Buzzard, offset by new volumes at Ettrick and Long Lake. Buzzard DD&A rates are lower than our corporate average while DD&A at Ettrick and Long Lake is higher.

During the quarter, we began depleting our Long Lake assets. The Long Lake depletion rate is higher than our corporate average and increased our consolidated average depletion cost by $0.76/boe.

In the UK North Sea, our Buzzard depletion rate decreased from last year as successful development drilling increased our proved reserve estimates at the end of 2009. This lower depletion rate reduced our corporate average by $0.60/boe. Elsewhere in the UK, successful development drilling at Telford increased proved reserve estimates at the end of 2009, which significantly reduced the Scott/Telford depletion rate. This was partially offset by new volumes from the Ettrick field, decreasing our corporate average by $0.86/boe.

Depletion rates in Yemen increased our corporate average $0.33/boe. As the fields mature and production declines, our capital is focused on accessing the remaining reserves, thereby increasing our depletion rates. In the Gulf of Mexico, positive reserve revisions and lower estimates for future abandonment costs reduced our corporate average depletion rate of $1.04/boe.

Higher Canadian depletion costs increased our corporate average by $0.27/boe. Our 2010 depletion rates are higher at our CBM and natural gas properties as reserve estimates at the end of 2009 were reduced by lower gas prices. The higher depletion rates on our natural gas properties were partially offset by lower rates on our heavy oil properties, where we had positive price-related proved reserves revisions at the end of 2009.

Exploration Expense

	Three Months Ended March 31	
	2010	**2009**
Seismic	12	12
Unsuccessful Drilling	41	11
Other	40	30
Total Exploration Expense	93	53
New Growth Exploration	199	163
Geological and Geophysical Costs	12	12
Total Exploration Expenditures	211	175
Exploration Expense as a % of Exploration Expenditures	44%	30%

Higher exploration expense decreased net income for the quarter by $40 million

Exploration expenditures increased $36 million or 22% from the same period last year as we continue to invest in our core basins in the Gulf of Mexico, the North Sea and Canada.

In the Eastern Gulf of Mexico, we made a significant oil discovery at Appomattox, where we drilled an exploratory well and two appraisal sidetracks. Appomattox is the third discovery in the area following previous successful drilling at Shiloh and Vicksburg. Additional appraisal wells for Appomattox are planned for later in the year and we are investigating development options for Appomattox and Vicksburg, located six miles east. We have a 25% interest in Vicksburg and a 20% interest in Appomattox and Shiloh, with Shell Offshore Inc. operating all three.

In the UK, we are assessing development options for our Golden Eagle area to determine the appropriate configuration. We are in the process of completing the acquisition of additional land in the area and plan to drill an exploration well here mid-year. The Golden Eagle area includes our 34% operated interest in Golden Eagle and Hobby and our 46% operated interest in Pink. We plan to drill up to five additional exploration and appraisal wells in 2010.

In Canada, we are investing in our shale gas project in the Dilly Creek area of the Horn River basin in north-east British Columbia. We currently have six wells on production and they are meeting expectations with respect to production and decline profiles. During the quarter, we successfully drilled an eight well pad to further test the play. These wells are expected to be on stream later this year following completion operations. In north-east British Columbia, we have approximately 90,000 acres in the Dilly Creek area and a further 38,000 acres in the Cordova area, with a 100% working interest in each.

Exploration expense increased $40 million or 75% from the same period last year as higher unsuccessful drilling costs were partially offset by a decrease in exploration G&A. During the quarter, we drilled two unsuccessful wells in the North Sea. The Brand well in Norway and the Deacon well in the UK failed to encounter hydrocarbons and we expensed drilling costs of $25 million and $14 million, respectively.

ENERGY MARKETING

	Three Months Ended March 31	
	2010	**2009**
Physical Sales [1]	10,114	9,945
Physical Purchases [1]	(9,896)	(9,802)
Net Financial Transactions [2]	(64)	48
Change in Fair Market Value of Inventory	(68)	76
Marketing Revenue	86	267
Transportation Expense	(122)	(165)
Other	(1)	5
Net Marketing Revenue	(37)	107
Contribution to Net Marketing Revenue by Region		
North America	(35)	104
Asia	1	12
Europe	(3)	(9)
Net Marketing Revenue	(37)	107
DD&A	(5)	(4)
General and Administrative	(21)	(23)
Other	(4)	3
Marketing Contribution to Income before Income Taxes	(67)	83
North America		
Natural Gas		
Physical Sales Volumes [3] (bcf/d)	4.8	5.1
Transportation Capacity (bcf/d)	1.5	1.6
Storage Capacity (bcf)	31.9	33.5
Financial Volumes [4] (bcf/d)	6.0	15.6
Crude Oil		
Physical Sales Volumes [3] (mbbls/d)	754	806
Storage Capacity (mbbls)	2,968	2,757
Financial Volumes [4] (mbbls/d)	755	915
Power		
Physical Sales Volumes [3] (GWh/d)	10	5
Generation Capacity (MW)	87	87
Asia		
Physical Sales Volumes [3] (mbbls/d)	91	129
Financial Volumes [4] (mbbls/d)	290	322
Europe		
Financial Volumes [4] (mbbls/d)	603	507
Value-at-Risk		
Quarter-end	13	19
High	15	24
Low	9	18
Average	12	20

[1] Marketing's physical sales, physical purchases and net financial transactions are reported within marketing revenue as detailed in the notes to the unaudited consolidated financial statements.
[2] Net financial transactions include all gains and losses on financial derivatives and the unrealized portion of gains and losses on physical purchase and sale contracts.
[3] Excludes inter-segment transactions. Physical volumes represent amounts delivered during the quarter.
[4] Financial volumes represent amounts largely acquired to economically hedge physical transactions during the quarter.

Lower contribution from Energy Marketing decreased net income by $151 million

During the quarter, we continued our strategic review resulting in the successful sale of the European gas and power business, which generated $15 million of cash proceeds. We have substantially completed negotiations for the sale of our North American natural gas business subject to finalizing documentation and customary closing conditions. We expect to sign the agreement in the second quarter and close the sale in the third quarter. The sale is expected to be cash neutral and we expect to recognize a non-cash loss of between $250 and $290 million. This loss primarily relates to the transfer of long-term natural gas physical transportation commitments that are less valuable with increased gas supplies that reduce the need for transport services. Although volatile on a quarterly basis, we have had success with our marketing business over the last 10 years generating about $800 million of positive cash flow.

Results from energy marketing are lower than last year's results as a result of strong crude oil results in the first quarter of 2009 and strong natural gas income reported in the fourth quarter, together with lower results this quarter.

In 2010, the group's results were lower as global crude demand increased prices and flattened the forward contango curve. Early in the first quarter, gains were generated from blending physical crudes and inventory management strategies. These were substantially offset late in the quarter by a flattening forward contango curve, widening heavy differentials and a weaker US dollar. In 2009, record results were generated from the steep crude oil forward price curve as near-term crude oil prices were negatively impacted by the global economic recession.

During the first quarter of 2010, our North America natural gas business continued to face a challenging environment as declining natural gas spot prices reduced the reported value of our gas inventories and transportation spreads between producing and consuming regions remained narrow impacting our ability to generate profits as we moved gas to different regions. These losses partially offset related gains reported in the previous quarter.

The first quarter natural gas losses in 2009 were due to exiting the last of our 2008 basis trading positions as we eliminated this activity. Our inventory and time spread strategy experienced losses in both the first quarters of 2010 and 2009, largely related to the declining value of inventory. Typically, natural gas prices fall in the first part of the year as winter demand declines and the injection season begins. Our inventory is valued at the spot market price and losses were reported in the first quarter as natural gas prices decreased relative to year end. Losses on this strategy were consistent year over year. We recognized gains in the fourth quarter as spot natural gas prices increased from stronger winter demand.

Results from our marketing group vary by quarter and historical results are not necessarily indicative of results to be expected in future quarters. Quarterly marketing results depend on a variety of factors such as market volatility, changes in time and location spreads, the manner in which we use our storage and transportation assets and the change in value of the financial instruments we use to hedge these assets.

Composition of Net Marketing Revenue

	Three Months Ended March 31	
	2010	**2009**
Trading Activities (Physical and related Financial)	(38)	101
Non-Trading Activities	1	6
Total Net Marketing Revenue	(37)	107

Trading Activities

In energy marketing, we enter into contracts to purchase and sell crude oil and natural gas as well as storage and transportation contracts to capture time and location differences. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all financial and derivative contracts not designated as hedges for accounting purposes using fair value accounting and record the change in fair value in marketing and other income. The fair value of these instruments is included with amounts receivable or payable and they are classified as long-term or short-term based on their anticipated settlement date.

Other Activities

We enter into fee for service contracts related to transportation, storage and sales of third-party oil and gas. In addition, we earn income from our power generation facilities at Balzac and Soderglen.

Fair Value of Derivative Contracts

Our processes for estimating and classifying the fair value of our derivative contracts are consistent with those in place at December 31, 2009.

At March 31, 2010, the fair value of our derivative contracts in our energy marketing trading activities was $43 million. These derivatives are used to economically hedge our physical storage and transportation contracts which cannot be carried at fair value until they are used. Below is a breakdown of the derivative fair value by valuation method and contract maturity.

	Maturity				
	< 1 year	1-3 years	4-5 years	> 5 years	Total
Level 1 – Actively Quoted Markets	(68)	(79)	(9)	–	(156)
Level 2 – Based on Other Observable Pricing Inputs	93	52	10	6	161
Level 3 – Based on Unobservable Pricing Inputs	17	21	–	–	38
Total	42	(6)	1	6	43

Changes in Fair Value of Derivative Contracts

	Total
Fair Value at December 31, 2009	23
Change in Fair Value of Contracts	19
Net Losses (Gains) on Contracts Closed	1
Changes in Valuation Techniques and Assumptions [1]	–
Fair Value at March 31, 2010	43

[1] Our valuation methodology has been applied consistently in each period.

The fair values of our derivative contracts will be realized over time as the related contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials. The average term of our derivative contracts is approximately 1.2 years. Those maturing beyond one year primarily relate to North American natural gas positions.

CHEMICALS

Higher Chemicals contribution increased net income by $4 million

Chlor-alkali and chlorate sales revenues in North America were lower during the quarter than the same period last year. Chlorate revenue decreased 8% despite a 12% increase in volumes, as the average price received was 18% lower than last year. Chlor-alkali sale volumes remained consistent; however, price decreases due to competition reduced our revenue by 12%. In Brazil, our revenues were consistent with the first quarter of 2009, as the impact of a slight increase in volumes was offset by a small decrease in price.

The stronger Canadian dollar at March 31, 2010 generated foreign exchange gains of $7 million on the Canexus US-dollar denominated debt. This was higher than the first quarter of 2009 when our chemicals operations recognized foreign exchange translation losses of $6 million.

CORPORATE EXPENSES

General and Administrative (G&A)

	Three Months Ended March 31	
	2010	**2009**
General and Administrative Expense before Stock-Based Compensation	116	100
Stock-Based Compensation [1]	2	–
Total General and Administrative Expense	118	100

[1] Includes cash and non-cash expenses related to our tandem option and stock appreciation rights plans.

Higher G&A costs decreased net income by $18 million

G&A expenditures before stock-based compensation increased 16% from the first quarter of 2009 primarily as a result of higher employee costs.

Fluctuations in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. Stock-based compensation increased marginally during the quarter as our share price was largely unchanged from the end of 2009. Cash payments made in connection with our stock-based compensation programs during the three month period ended March 31, 2010 were $3 million (2009 – nil).

Interest

	Three Months Ended March 31	
	2010	**2009**
Interest	98	94
Less: Capitalized	(18)	(26)
Net Interest Expense	80	68
Effective Interest Rate	5.2%	4.9%

Higher net interest expense reduced net income by $12 million

Our financing costs increased $4 million from the first quarter of 2009. In July 2009, we issued US$1 billion of long-term notes and additional interest expense in the quarter related to this debt was $17 million. This was partially offset by the strengthening Canadian dollar which decreased our US-denominated interest expense by $13 million.

Capitalized interest was $8 million lower than 2009 as we completed major development projects. Construction completion of our Long Lake Phase 1 facilities and our Ettrick project in the UK North Sea reduced capitalized interest by $10 million and $8 million, respectively. These decreases were partially offset by $6 million of additional capitalized interest on our major development project at Usan, offshore West Africa. We also continue to capitalize interest on the construction of the fourth platform at Buzzard and on our Chemicals technical conversion project in North Vancouver.

Income Taxes

	Three Months Ended March 31	
	2010	**2009**
Current	259	118
Future	(100)	(87)
Total Provision for Income Taxes	159	31

Higher taxes reduced net income by $128 million

Stronger commodity prices in the first quarter compared to the same period last resulted in an increase to our tax expense. Our future tax expense in 2009 also included the effect of a reduction in Canadian tax rates. Our income tax provision includes current taxes in the United Kingdom, Yemen, Norway, Colombia and the United States.

Other

	Three Months Ended March 31	
	2010	**2009**
Decrease in Fair Value of Crude Oil Put Options	(16)	(16)

In the fourth quarter of 2009, we purchased put options on 90,000 bbls/d of our 2010 crude oil production. These options establish a WTI floor price of US$50/bbl and provide a base level of price protection without limiting our upside to higher prices. Options on 60,000 bbls/d settle monthly, while the remaining options settle annually. These options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on these options at each period end. The put options were purchased for $39 million and are carried at fair value. At March 31, 2010, higher crude oil prices reduced the fair value of the options to approximately $1 million, $16 million lower than the end of 2009. In 2009, we recorded a fair value loss of $16 million on our 2009 crude oil put option program.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

	March 31	December 31
	2010	**2009**
Net Debt [1]		
Bank Debt	1,770	1,803
Public Senior Notes	4,831	4,982
Total Senior Debt	6,601	6,785
Subordinated Debt	453	466
Total Debt	7,054	7,251
Less: Cash and Cash Equivalents	(1,997)	(1,700)
Total Net Debt	5,057	5,551
Equity	7,827	7,646

[1] Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.

Net Debt

Our net debt levels are directly related to our operating cash flows and our capital expenditure activities. Changes in net debt are related to:

Capital Investment	(556)
Cash Flow from Operating Activities [1]	798
Excess Cash Generated	242
Dividends on Common Shares	(26)
Issue of Common Shares	25
Changes in Restricted Cash	15
Foreign Exchange Translation of US-dollar Debt and Cash	141
Other	97
Decrease in Net Debt	494

[1] Includes changes in non-cash working capital. For the three months ended March 31, 2010, $256 million was included as a source of cash flow.

Our net debt decreased approximately $500 million from December 31, 2009 as our cash flow from operating activities exceeded our first quarter capital investment by $242 million. Additionally, the stronger Canadian dollar relative to the US dollar, decreased our US dollar denominated debt and US dollar cash. This reduced net debt by $141 million. Our available liquidity at March 31, 2010 was approximately $3.6 billion, comprised of cash on hand and undrawn credit facilities. Operating cash flows in the oil and gas industry can be volatile as short-term commodity prices are driven by existing supply and demand fundamentals and market volatility. We periodically invest through the lows of the current commodity market to create future growth and value for our shareholders for the long-term. Changes in our non-cash working capital can vary between quarters as our energy marketing

net working capital position fluctuates depending on timing of settlement of outstanding positions, the movement in commodity prices and inventory cycles.

Change in Working Capital

	March 31 **2010**	December 31 **2009**	Increase/ (Decrease)
Cash and Cash Equivalents	1,997	1,700	297
Restricted Cash	178	198	(20)
Accounts Receivable	2,635	2,788	(153)
Inventories and Supplies	574	680	(106)
Accounts Payable and Accrued Liabilities	(3,084)	(3,038)	(46)
Other	(1)	70	(71)
Net Working Capital	2,299	2,398	

We generated cash from reducing working capital requirements since the end of 2009. Cash was generated by selling commodity inventory held by our energy marketing group and timing of crude oil sales in the UK. We sold natural gas trading inventory during the winter heating season. In addition, we are reducing our trading activity to focus on supporting our core physical business as a producer/marketer. Working capital was also reduced from the timing of current tax payments to governments.

At March 31, 2010, our restricted cash consists of margin deposits of $178 million (December 31, 2009 – $198 million) related to exchange-traded derivative financial contracts used by our energy marketing group to hedge physical commodities, and storage, transportation and customer sales contracts. We are required to maintain margin for net out-of-the-money derivative financial contracts.

Outlook for Remainder of 2010

We expect our 2010 production to range between 230,000 and 280,000 boe/d (200,000 and 250,000 boe/d after royalties). We expect to continue to fund our 2010 capital investment program using cash flow from operating activities.

Our future liquidity and ability to fully fund capital requirements generally depends upon operating cash flows, existing working capital, unused committed credit facilities, and our ability to access debt and equity markets. Given the long cycle time of some of our development projects and volatile commodity prices, it is not unusual in any year for capital expenditures to exceed our cash flow. Changes in commodity prices, particularly crude oil as it represents approximately 85% of our current production, can impact our operating cash flows. We use short-term contracts to sell the majority of our oil and gas production, exposing us to short-term price movements. A US$1/bbl change in WTI above US$50/bbl is projected to increase or decrease our cash flow from operating activities, after cash taxes, by approximately $36 million for the remainder of 2010. Our exposure to a $0.01 change in the US to Canadian dollar exchange rate is projected to increase or decrease our cash flow by approximately $27 million for the remainder of 2010. While commodity prices can fluctuate significantly in the short term, we believe that over the longer term, commodity prices will continue to remain strong as a result of growth in world demand and delays or shortages in supply growth. We believe that our existing liquidity, balance sheet capacity and capital investment flexibility provides us with the ability to fund our obligations during periods of lower commodity prices.

During the first three months of 2010, we have incurred approximately 20% of our 2010 capital budget and generated cash flow from operating activities in excess of our capital investment by $242 million. We currently have approximately $2 billion of cash and cash equivalents on hand and as well as significant undrawn committed credit facilities available. At March 31, 2010, we had unsecured term credit facilities of US$3.1 billion in place that are available until 2012, of which US$1.5 billion was drawn and US$385 million was used to support outstanding letters of credit. We also have approximately $466 million of undrawn, uncommitted, unsecured credit facilities, of which $116 million was used to support outstanding letters of credit. The average length-to-maturity of our public debt is approximately 17 years.

Contractual Obligations, Commitments and Guarantees

We have assumed various contractual obligations and commitments in the normal course of our operations and financing activities. We included these obligations and commitments in our MD&A in our 2009 Form 10-K.

During the quarter, we sold our European gas and power marketing business. We agreed to maintain our parental guarantees to the existing counterparties until the purchaser is able to replace them. The guarantees expire at the earlier of the purchaser replacing the guarantees and July 25, 2010. We are obligated to perform under the guarantees only if the purchaser does not meet its obligations to the counterparties. Our total exposure is $275 million for which the purchaser has provided us an indemnity and a letter of credit from a highly rated financial institution.

There have been no other significant developments since year-end.

CONTINGENCIES

There are a number of lawsuits and claims pending, the ultimate result of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations. These matters are described in *Legal Proceedings* in Item 3 contained in our 2009 Form 10-K. There have been no significant developments since year-end.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

International Financial Reporting Standards Adoption Plan

We are required to adopt International Financial Reporting Standards (IFRS) for our interim and annual financial reporting purposes beginning January 1, 2011. A project team, consisting of dedicated and experienced personnel who have IFRS knowledge, has been set up to manage this transition and to ensure successful implementation within the required timeframe.

We provided an update on the status of our project in our 2009 Annual Report on Form 10-K, including a summary of accounting differences between Canadian GAAP and IFRS.

The following chart is a summary of our progress since our previous update. Significant changes are highlighted below:

Key Activity	Key Milestone	Status
Financial Information		
• Identify differences between Canadian GAAP and IFRS • Revise accounting policies under IFRS • Identify potential adjustments to initial IFRS financial statements • Develop IFRS-compliant financial statements, including transition period disclosures	• Comprehensive analysis of IFRS differences identified in the diagnostics phase • Senior management approval of IFRS accounting policies • Develop draft IFRS financial statements and disclosures	• Comprehensive analysis completed mid 2009 • Received senior management approval of IFRS accounting policies • Areas of potential adjustment to opening balance sheet identified • **Analysis to support opening balance sheet adjustments is underway** • **Draft IFRS financial statements and note disclosures are substantially complete**
Training and Communication		
• Develop and deliver targeted IFRS training to employees and management • Ensure internal and external stakeholders receive ongoing appropriate communications • Develop and deliver targeted IFRS training to senior management and Board of Directors	• Delivery of training in 2009 targeted to affected employees • Ongoing communication with major internal and external stakeholders	• Targeted training completed in 2009 • Strategy for follow-up training in 2010 developed • Regular communication with Project Steering Committee, senior management and Audit Committee throughout the year • Quarterly disclosure of project status in MD&A
Information Technology		
• Ensure systems are able to adequately support conversion to IFRS and ongoing financial reporting	• Be IFRS data capture ready January 1, 2010 • Ensure dual GAAP reporting capability throughout 2010	• System testing for IFRS data capture complete • Dual GAAP reporting capability testing complete • **IFRS data capture in the financial system has commenced**
Business Process		
• Ensure business processes and control environment properly support conversion to IFRS and ongoing financial reporting	• Implement necessary business process and key control changes to ensure adequate internal control over financial reporting	• Necessary changes to business process have been designed • Key controls designed to ensure adequate internal control over financial reporting on IFRS results throughout 2010

At this time, we cannot quantify the impact that the adoption of IFRS will have on our future results of operations or financial position. Additional disclosure of the key elements of our plan and progress on the project will be provided as we move toward the changeover date. We continue to monitor the development of new standards and any changes will be incorporated as required.

US Pronouncements

In January 2010, the Financial Accounting Standards Board (FASB) issued guidance to improve fair value measurement disclosures. The guidance requires entities to describe transfers between the three levels of the

fair value hierarchy and present items separately in the level 3 reconciliation. This guidance is consistent with fair value measurement disclosures adopted for Canadian GAAP in 2009. Adoption of this guidance did not have an impact on our results of operations or financial position.

EQUITY SECURITY REPURCHASES

During the quarter, we made no purchases of our own equity securities.

SUMMARY OF QUARTERLY RESULTS

	2008			2009				2010
(Cdn$ millions, except per share amounts)	Jun	Sep	Dec	Mar	Jun	Sep	Dec	Mar
Net Sales	2,071	2,213	1,270	1,048	1,200	1,097	1,550	1,501
Net Income (Loss)	380	886	(181)	135	20	122	259	185
Earnings (Loss) Per Common Share ($/share)								
Basic	0.72	1.68	(0.35)	0.26	0.04	0.23	0.50	0.35
Diluted	0.70	1.66	(0.35)	0.26	0.04	0.23	0.49	0.35

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Management's Discussion and Analysis of Financial Condition and Results of Operations*, constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "*anticipate*", "*believe*", "*intend*", "*plan*", "*expect*", "*estimate*", "*budget*", "*outlook*", "*forecast*" or other similar words, and include statements relating to or associated with individual wells, regions or projects. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future capital expenditures and their allocation to exploration and development activities;
- future earnings;
- future asset acquisitions or dispositions;
- future sources of funding for our capital program;
- future debt levels;
- availability of committed credit facilities;
- possible commerciality;
- development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future sources of liquidity, cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of current and long-term assets;
- ultimate recoverability of reserves or resources;
- expected finding and development costs;
- expected operations costs;
- future demand for chemical products;
- estimates on a per share basis;
- future foreign currency exchange rates;
- future expenditures and future allowances relating to environmental matters;
- dates by which certain areas will be developed, will come on-stream or reach expected operating capacity; and
- changes in any of the foregoing.

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others:

- market prices for oil and gas and chemical products;
- our ability to explore, develop, produce and transport crude oil and natural gas to markets;
- ultimate effectiveness of design modification to facilities;
- the results of exploration and development drilling and related activities;
- volatility in energy trading markets;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations;
- renegotiations of contracts;
- results of litigation, arbitration or regulatory proceedings;
- political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and
- other factors, many of which are beyond our control.

These risks, uncertainties and other factors and their possible impact are discussed more fully in the sections titled *Risk Factors* in Item 1A and *Quantitative and Qualitative Disclosures About Market Risk* and in Item 7A of our 2009 Form 10-K. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on an assessment of all information at that time.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the statements contained herein, which are made as of the date hereof and, except as required by law, we undertake no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Nexen Inc.
Unaudited Consolidated Statement of Income
For the Three Months Ended March 31

(Cdn$ millions, except per share amounts)	2010	2009
Revenues and Other Income		
Net Sales	1,501	1,048
Marketing and Other (Note 14)	151	257
	1,652	1,305
Expenses		
Operating	422	305
Depreciation, Depletion, Amortization and Impairment	388	409
Transportation and Other	202	201
General and Administrative	118	100
Exploration	93	53
Interest (Note 9)	80	68
	1,303	1,136
Income before Provision for Income Taxes	349	169
Provision for (Recovery of) Income Taxes		
Current	259	118
Future	(100)	(87)
	159	31
Net Income	190	138
Less: Net Income Attributable to Canexus Non-Controlling Interests	5	3
Net Income Attributable to Nexen Inc.	185	135
Earnings Per Common Share ($/share) (Note 15)		
Basic	0.35	0.26
Diluted	0.35	0.26

See accompanying notes to the Unaudited Consolidated Financial Statements.

Nexen Inc.
Unaudited Consolidated Balance Sheet

(Cdn$ millions, except share amounts)	March 31 **2010**	December 31 **2009**
Assets		
Current Assets		
Cash and Cash Equivalents	1,997	1,700
Restricted Cash	178	198
Accounts Receivable (Note 2)	2,635	2,788
Inventories and Supplies (Note 3)	574	680
Other	102	185
Total Current Assets	5,486	5,551
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $10,931 (December 31, 2009 – $10,807)	15,381	15,492
Goodwill	330	339
Future Income Tax Assets	1,238	1,148
Deferred Charges and Other Assets (Note 5)	328	370
Total Assets	22,763	22,900
Liabilities		
Current Liabilities		
Accounts Payable and Accrued Liabilities (Note 8)	3,084	3,038
Accrued Interest Payable	77	89
Dividends Payable	26	26
Total Current Liabilities	3,187	3,153
Long-Term Debt (Note 9)	7,054	7,251
Future Income Tax Liabilities	2,804	2,811
Asset Retirement Obligations (Note 11)	932	1,018
Deferred Credits and Other Liabilities (Note 12)	959	1,021
Equity		
Nexen Inc. Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2010 – 524,046,867 shares		
2009 – 522,915,843 shares	1,076	1,049
Contributed Surplus	–	1
Retained Earnings	6,881	6,722
Accumulated Other Comprehensive Loss	(201)	(190)
Total Nexen Inc. Shareholders' Equity	7,756	7,582
Canexus Non-Controlling Interests	71	64
Total Equity	7,827	7,646
Commitments, Contingencies and Guarantees (Note 16)		
Total Liabilities and Equity	22,763	22,900

See accompanying notes to the Unaudited Consolidated Financial Statements.

Nexen Inc.
Unaudited Consolidated Statement of Cash Flows
For the Three Months Ended March 31

(Cdn$ millions)	2010	2009
Operating Activities		
Net Income	190	138
Charges and Credits to Income not Involving Cash (Note 17)	265	319
Exploration Expense	93	53
Changes in Non-Cash Working Capital (Note 17)	256	420
Other	(6)	(141)
	798	789
Financing Activities		
Proceeds from (Repayment of) Term Credit Facilities, Net	–	1,011
Proceeds from (Repayment of) Canexus Term Credit Facilities, Net	22	10
Dividends Paid on Common Shares	(26)	(26)
Distributions Paid to Canexus Non-Controlling Interests	(4)	(4)
Issue of Common Shares and Exercise of Tandem Options for Shares	25	23
	17	1,014
Investing Activities		
Capital Expenditures		
Exploration and Development	(492)	(702)
Proved Property Acquisitions	–	(757)
Energy Marketing, Chemicals, Corporate and Other	(64)	(45)
Proceeds on Disposition of Assets	15	14
Changes in Non-Cash Working Capital (Note 17)	88	19
Changes in Restricted Cash	15	(314)
Other	(3)	(2)
	(441)	(1,787)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(77)	35
Increase in Cash and Cash Equivalents	297	51
Cash and Cash Equivalents – Beginning of Period	1,700	2,003
Cash and Cash Equivalents – End of Period [1]	1,997	2,054

[1] Cash and cash equivalents at March 31, 2010 consist of cash of $257 million and short-term investments of $1,740 million (March 31, 2009 – cash of $182 million and short-term investments of $1,872 million).

See accompanying notes to the Unaudited Consolidated Financial Statements.

Nexen Inc.
Unaudited Consolidated Statement of Equity
For the Three Months Ended March 31

(Cdn$ millions)	2010	2009
Common Shares, Beginning of Period	1,049	981
Issue of Common Shares	24	23
Exercise of Tandem Options for Shares	1	–
Accrued Liability Relating to Tandem Options Exercised for Common Shares	2	–
Balance at End of Period	1,076	1,004
Contributed Surplus, Beginning of Period	1	2
Exercise of Tandem Options	(1)	–
Balance at End of Period	–	2
Retained Earnings, Beginning of Period	6,722	6,290
Net Income Attributable to Nexen Inc.	185	135
Dividends Paid on Common Shares (Note 13)	(26)	(26)
Balance at End of Period	6,881	6,399
Accumulated Other Comprehensive Loss, Beginning of Period	(190)	(134)
Other Comprehensive Income (Loss) Attributable to Nexen Inc.	(11)	6
Balance at End of Period [1]	(201)	(128)
Canexus Non-Controlling Interests, Beginning of Period	64	52
Net Income Attributable to Non-Controlling Interests	6	3
Distributions Paid to Non-Controlling Interests	(4)	(4)
Issue of Partnership Units to Non-Controlling Interests	5	1
Balance at End of Period	71	52

[1] Comprised of unrealized foreign currency translation adjustment.

See accompanying notes to the Unaudited Consolidated Financial Statements.

Nexen Inc.
Unaudited Consolidated Statement of Comprehensive Income
For the Three Months Ended March 31

(Cdn$ millions)	2010	2009
Net Income Attributable to Nexen Inc.	185	135
Other Comprehensive Income (Loss), Net of Income Taxes:		
Foreign Currency Translation Adjustment		
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	(147)	174
Net Gains (Losses) on Foreign-Denominated Debt Hedges of Self-Sustaining Foreign Operations [1]	136	(168)
Other Comprehensive Income (Loss) Attributable to Nexen Inc.	(11)	6
Comprehensive Income Attributable to Nexen Inc.	174	141

[1] Net of income tax expense for the three months ended March 31, 2010 of $20 million (2009 – $24 million recovery).

See accompanying notes to the Unaudited Consolidated Financial Statements.

1. ACCOUNTING POLICIES

Our Unaudited Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States GAAP on the Unaudited Consolidated Financial Statements is disclosed in Note 20. In the opinion of management, the Unaudited Consolidated Financial Statements contain all adjustments of a normal and recurring nature necessary to present fairly Nexen Inc.'s (Nexen, we or our) financial position at March 31, 2010 and December 31, 2009 and the results of our operations and our cash flows for the three months ended March 31, 2010 and 2009.

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Unaudited Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates on an ongoing basis, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of derivative assets and liabilities, capital adequacy and determination of proved reserves. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. The results of operations and cash flows for the three months ended March 31, 2010 are not necessarily indicative of the results of operations or cash flows to be expected for the year ending December 31, 2010. As at April 26, 2010, there are no material subsequent events requiring additional disclosure in or amendment to these financial statements.

These Unaudited Consolidated Financial Statements should be read in conjunction with our Audited Consolidated Financial Statements included in our 2009 Form 10-K. The accounting policies we follow are described in Note 1 of the Audited Consolidated Financial Statements included in our 2009 Form 10-K.

Changes in Accounting Policies

Oil and Gas Reserve Estimates
On January 6, 2010, the Financial Accounting Standards Board issued guidance for *Oil and Gas Reserve Estimation and Disclosure*, which is effective for years ended December 31, 2009. The guidance expands the definition of oil and gas producing activities to: i) include unconventional sources such as oil sands; ii) change the price used in reserve estimation from the year-end price to the simple average of the first-day-of-the-month price for the previous 12 months, and iii) require disclosures for geographic areas that represent 15% or more of proved reserves.

We follow the successful efforts method of accounting for our oil and gas activities, which use the estimated proved reserves we believe are recoverable from our oil and gas properties. Specifically, reserves estimates are used to calculate our unit-of-production depletion rates and to assess, when necessary, our oil and gas assets for impairment. Adoption of these amendments changed our estimate of reserves used to calculate depletion in 2010. As a result of the amendments, depletion expense for the three months ended March 31, 2010 increased by $14 million, net income decreased by $9 million, and earnings per common share decreased by $0.02/share.

2. ACCOUNTS RECEIVABLE

	March 31 **2010**	December 31 **2009**
Trade		
Energy Marketing	1,385	1,410
Energy Marketing Derivative Contracts (Note 6)	267	466
Oil and Gas	867	823
Chemicals and Other	46	44
	2,565	2,743
Non-Trade	123	99
	2,688	2,842
Allowance for Doubtful Receivables	(53)	(54)
Total	2,635	2,788

3. INVENTORIES AND SUPPLIES

	March 31 **2010**	December 31 **2009**
Finished Products		
Energy Marketing	442	548
Oil and Gas	25	25
Chemicals and Other	12	12
	479	585
Work in Process	10	7
Field Supplies	85	88
Total	574	680

4. SUSPENDED EXPLORATION WELL COSTS

The following table shows the changes in capitalized exploratory well costs during the three months ended March 31, 2010 and the year ended December 31, 2009, and does not include amounts that were initially capitalized and subsequently expensed in the same period. Suspended exploration well costs are included in property, plant and equipment.

	Three Months Ended March 31 **2010**	Year Ended December 31 **2009**
Beginning of Period	794	518
Exploratory Well Costs Capitalized Pending the Determination of Proved Reserves	146	396
Capitalized Exploratory Well Costs Charged to Expense	(2)	(56)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	–	(21)
Effects of Foreign Exchange Rate Changes	(14)	(43)
End of Period	924	794

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed and shows the number of projects for which exploratory well costs have been capitalized for a period greater than one year after the completion of drilling.

	March 31 **2010**	December 31 **2009**
Capitalized for a Period of One Year or Less	425	383
Capitalized for a Period of Greater than One Year	499	411
Total	924	794
Number of Projects that have Exploratory Well Costs Capitalized for a Period Greater than One Year	13	12

As at March 31, 2010, we have exploratory costs that have been capitalized for more than one year relating to our interests in eight exploratory blocks in the North Sea ($174 million), certain coalbed methane and shale gas exploratory activities in Canada ($194 million), two exploratory blocks in the Gulf of Mexico ($113 million), and our interest in an exploratory block offshore Nigeria ($18 million). These costs relate to projects with successful exploration wells for which we have not been able to recognize proved reserves. We are assessing all of these wells and projects, and are working with our partners to prepare development plans, drill additional appraisal wells or otherwise assess commercial viability.

Aging of Suspended Exploration Wells Greater than One Year	United Kingdom	Canada	United States	Nigeria	Total
1-3 years	119	194	42	–	355
4-5 years	55	–	71	–	126
Greater than 5 years	–	–	–	18	18
Total	174	194	113	18	499

5. DEFERRED CHARGES AND OTHER ASSETS

	March 31 **2010**	December 31 **2009**
Long-Term Energy Marketing Derivative Contracts (Note 6)	200	225
Crude Oil Put Options and Natural Gas Swaps (Note 6)	–	4
Defined Benefit Pension Assets	56	60
Long-Term Capital Prepayments	23	27
Other	49	54
Total	328	370

6. FINANCIAL INSTRUMENTS

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Our other financial instruments, including accounts receivable, accounts payable, accrued interest payable, dividends payable, short-term borrowings and long-term debt, are carried at cost or amortized cost. The carrying values of our short-term receivables and payables approximate their fair value because the instruments are near maturity.

In our energy marketing group, we enter into contracts to purchase and sell crude oil, natural gas and other energy commodities, and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We categorize our derivative instruments as trading or non-trading activities and carry the instruments at fair value on our balance sheet. The derivatives section below details our derivatives and fair values as at March 31, 2010. The fair values are included with accounts receivable or payable and are classified as long-term or short-term based on anticipated settlement date. Any change in fair value is included in marketing and other income. Related amounts posted as margin for exchange traded positions are recorded in restricted cash.

We carry our long-term debt at amortized cost using the effective interest rate method. At March 31, 2010, the estimated fair value of our long-term debt was $7,337 million (December 31, 2009 – $7,594 million) as compared to the carrying value of $7,054 million (December 31, 2009 – $7,251 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers.

Derivatives

(a) Derivative contracts related to trading activities

Our energy marketing group engages in various activities including the purchase and sale of physical commodities and the use of financial instruments such as commodity and foreign exchange futures, forwards and swaps to economically hedge exposures and generate revenue. These contracts are accounted for as derivatives and, where applicable, are presented net on the balance sheet in accordance with netting arrangements. The fair value and carrying amounts related to derivative instruments held by our energy marketing operations are as follows:

	March 31 **2010**	December 31 **2009**
Commodity Contracts	267	463
Foreign Exchange Contracts	–	3
Accounts Receivable (Note 2)	267	466
Commodity Contracts	200	225
Deferred Charges and Other Assets (Note 5) [1]	200	225
Total Trading Derivative Assets	467	691
Commodity Contracts	212	410
Foreign Exchange Contracts	13	46
Accounts Payable and Accrued Liabilities (Note 8)	225	456
Commodity Contracts	198	212
Foreign Exchange Contracts	1	–
Deferred Credits and Other Liabilities (Note 12) [1]	199	212
Total Trading Derivative Liabilities	424	668
Total Net Trading Derivative Contracts	43	23

[1] These derivative contracts settle beyond 12 months and are considered non-current; once settlement is within 12 months, they are included in accounts receivable or accounts payable.

Excluding the impact of netting arrangements, the fair value of derivative instruments is as follows:

	March 31 **2010**	December 31 **2009**
Current Trading Assets	2,116	2,625
Non-Current Trading Assets	613	716
Total Trading Derivative Assets	2,729	3,341
Current Trading Liabilities	2,074	2,615
Non-Current Trading Liabilities	612	703
Total Trading Derivative Liabilities	2,686	3,318
Total Net Trading Derivative Contracts	43	23

Trading revenues generated by our energy marketing group include gains and losses on derivative instruments and non-derivative instruments such as physical inventory. During the three months ended March 31, 2010 and 2009, the following trading revenues were recognized in marketing and other income:

	Three Months Ended March 31	
	2010	**2009**
Commodity	91	270
Foreign Exchange	(5)	(3)
Marketing Revenue	86	267

As an energy marketer, we may undertake several transactions during a period to execute a single sale of physical product. Each transaction may be represented by one or more derivative instruments including a physical buy, physical sell, and in many cases, numerous financial instruments for economic hedging and trading purposes. The absolute notional volumes associated with our derivative instrument transactions for the three months ended March 31, 2010 and 2009, are as follows:

		Three Months Ended March 31	
		2010	**2009**
Natural Gas	bcf/d	15.2	28.6
Crude Oil	mmbbls/d	3.3	3.8
Power	GWh/d	280.8	212.3
Foreign Exchange	US$ millions	787	378
Foreign Exchange	Euro millions	53	153

(b) Derivative contracts related to non-trading activities

The fair value and carrying amounts of derivative instruments related to non-trading activities are as follows:

	March 31	December 31
	2010	**2009**
Accounts Receivable	1	13
Deferred Charges and Other Assets (Note 5) [1]	–	4
Total Non-Trading Derivative Assets	1	17
Accounts Payable and Accrued Liabilities (Note 8)	20	26
Total Non-Trading Derivative Liabilities	20	26
Total Net Non-Trading Derivative Assets [2]	(19)	(9)

[1] These derivative contracts settle beyond 12 months and are considered non-current.
[2] The net fair value of these derivatives is equal to the gross fair value before consideration of netting arrangements and collateral posted or received with counterparties.

Crude oil put options

In 2009, we purchased put options on 90,000 bbls/d of our 2010 crude oil production for $39 million. These options establish a WTI floor price of US$50/bbl on these volumes and provide a base level of price protection without limiting our upside to higher prices. Options on 60,000 bbls/d settle monthly, while the remaining options settle annually. These options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on these options at each period end. At March 31, 2010, higher crude oil prices reduced the fair value of the options to approximately $1 million, and we recorded a fair value loss during the period of $16 million in marketing and other income.

				Three Months Ended March 31, 2010	
	Notional Volumes	Term	Average Floor Price	Fair Value	Change in Fair Value
	(bbls/d)		(US$/bbl)		
WTI Crude Oil Put Options (monthly)	60,000	2010	50	1	(12)
WTI Crude Oil Put Options (annual)	30,000	2010	50	–	(4)
				1	(16)

Fixed-price natural gas contracts and natural gas swaps

We have fixed-price natural gas sales contracts and offsetting natural gas swaps that are not part of our trading activities. These sales contracts and swaps are carried at fair value and are classified as current based on their anticipated settlement date. Any change in fair value is included in marketing and other income.

				Three Months Ended March 31, 2010	
	Notional Volumes	Term	Average Price	Fair Value	Change in Fair Value
	(Gj/d)		($/Gj)		
Fixed-Price Natural Gas Contracts	15,514	2010	2.28	(4)	(7)
Natural Gas Swaps	15,514	2010	7.60	(16)	7
				(20)	–

(c) Fair value of derivatives

Our processes for estimating and classifying the fair value of our derivative contracts are consistent with those in place at December 31, 2009. The following table includes our derivatives carried at fair value for our trading and non-trading activities as at March 31, 2010. Financial assets and liabilities are classified in the fair value hierarchy in their entirety based on the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

Net Derivatives at March 31, 2010	Level 1	Level 2	Level 3	Total
Commodity Contracts	(156)	175	38	57
Foreign Exchange Contracts	–	(14)	–	(14)
Trading Derivatives	(156)	161	38	43
Non-Trading Derivatives	–	(19)	–	(19)
Total	(156)	142	38	24

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the three months ended March 31, 2010 is provided below:

	Level 3
Beginning of Period	42
Realized and Unrealized Gains (Losses)	7
Purchases	–
Settlements	(11)
Transfers Into Level 3	–
Transfers Out of Level 3	–
End of Period	38
Unsettled gains relating to instruments still held as of March 31, 2010	7

Items classified in Level 3 are generally economically hedged such that gains or losses on positions classified in Level 3 are often offset by gains or losses on positions classified in Level 1 or 2. Transfers into or out of Level 3 represent existing assets and liabilities that were either previously categorized as a higher level for which the inputs became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. Fair values of instruments in Level 3 are determined using broker quotes, pricing services and internally-developed inputs. We performed a sensitivity analysis of inputs used to calculate the fair value of Level 3 instruments. Using reasonably possible alternative assumptions, the fair value of Level 3 instruments would change by $13 million (December 31, 2009 – $12 million).

7. RISK MANAGEMENT

(a) Market risk

We invest in significant capital projects, purchase and sell commodities, issue short-term borrowings and long-term debt, and invest in foreign operations. These activities expose us to market risks from changes in commodity prices, foreign currency rates and interest rates, which could affect our earnings and the value of the financial instruments we hold. We use derivatives for trading and non-trading purposes as part of our overall risk management policy to manage these market exposures.

The following market risk discussion focuses on the commodity price risk and foreign currency risk related to our financial instruments as our exposure to interest rate risk is immaterial, given that the majority of our debt is fixed rate.

Commodity price risk

We are exposed to commodity price movements as part of our normal oil and gas operations, particularly in relation to the prices received for our crude oil and natural gas. Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in the global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes may also affect the value of our oil and gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they come due.

The majority of our oil and gas production is sold under short-term contracts, exposing us to the risk of price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. We actively manage these risks by using derivative contracts such as commodity put options.

Our energy marketing business is focused on providing services to our customers and suppliers to meet their energy commodity needs. We market and trade physical energy commodities in selected regions of the world, including crude oil, natural gas, electricity and other commodities. We do this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers.

In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts including energy-related futures, forwards, swaps and options, as well as foreign currency swaps or forwards.

We also seek to profit from our views on the future movement of energy commodity pricing relationships, primarily between different locations, time periods or product qualities. We do this by holding open positions, where the terms of physical or financial contracts are not completely matched to offsetting positions.

Our risk management activities include prescribed capital limits and the use of tools such as Value-at-Risk (VaR) and stress testing consistent with the methodology used at December 31, 2009. Our period end, high, low and average VaR amounts for the three months ended March 31, 2010 and the year ended December 31, 2009, are as follows:

Value-at-Risk	Three Months Ended March 31 **2010**	Year Ended December 31 **2009**
Period End	13	11
High	15	24
Low	9	9
Average	12	15

If a market shock occurred as in 2008, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of abnormal changes in prices on our positions.

Foreign currency risk

Foreign currency risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas and chemicals operations;
- commodity derivative contracts used primarily by our energy marketing group; and
- short-term borrowings and long-term debt.

In our oil and gas operations, we manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Cash inflows generated by our foreign operations and borrowings on our US-dollar debt facilities are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows.

We designate most of our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations. The foreign exchange gains or losses related to the effective portion of our designated US-dollar debt are included in accumulated other comprehensive income in shareholders' equity. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at March 31, 2010 and December 31, 2009 are as follows:

(US$ millions)	March 31 **2010**	December 31 **2009**
Net Investment in Self-Sustaining Foreign Operations	4,523	4,492
Designated US-Dollar Debt	4,523	4,492

For the three month period ended March 31, 2010, the ineffective portion of our US-dollar debt resulted in a net foreign exchange gain of $21 million ($19 million, net of income tax expense) and is included in marketing and other income. A one cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our accumulated other comprehensive income by approximately $45 million, net of income tax, and would increase or decrease our net income by approximately $6 million, net of income tax.

We also have exposures to currencies other than the US dollar including a portion of our UK operating expenses, capital spending and future asset retirement obligations which are denominated in British Pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies. In our energy marketing group, we enter into transactions in various currencies including Canadian and US dollars, British Pounds and Euros. We may actively manage significant currency exposures using forward contracts and swaps.

(b) Credit risk

Credit risk affects our oil, gas and chemicals operations, and our trading and non-trading derivative activities, and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposure is with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Approximately 70% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. Our processes to manage this risk are consistent with those in place at December 31, 2009.

At March 31, 2010, only two counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with a strong investment grade credit rating. No other counterparties made up more than 5% of our credit exposure. The following table illustrates the composition of credit exposure by credit rating.

Credit Rating	March 31 **2010**	December 31 **2009**
A or higher	67%	67%
BBB	25%	26%
Non-Investment Grade	8%	7%
Total	100%	100%

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts on non-derivative financial assets such as cash and cash equivalents, restricted cash, accounts receivable, as well as the fair value of derivative financial assets. We provided an allowance of $53 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

Collateral received from customers at March 31, 2010 includes $1 million of cash and $319 million of letters of credit. The cash received is included in accounts payable and accrued liabilities.

(c) Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they fall due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they come due, and to operate our energy marketing business. We generally rely on operating cash flows to provide liquidity and we also maintain significant undrawn committed credit facilities. At March 31, 2010, we had approximately $3.6 billion of cash and available committed lines of credit. This includes $2 billion of cash and cash equivalents on hand and undrawn term credit facilities of $1.6 billion, of which $391 million was supporting letters of credit at March 31, 2010. These facilities are available until 2012 unless extended. We also have about $466 million of undrawn, uncommitted credit facilities, of which $116 million was supporting letters of credit at March 31, 2010.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at March 31, 2010:

	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Long-Term Debt	7,144	–	1,771	854	4,519
Interest on Long-Term Debt [1]	7,724	350	700	658	6,016
Total	14,868	350	2,471	1,512	10,535

[1] Excludes interest on term credit facilities of $1.5 billion (US$1.5 billion) and Canexus term credit facilities of $247 million (US$244 million) as the amounts drawn on the facilities fluctuate. Based on amounts drawn at March 31, 2010 and existing variable interest rates, we would be required to pay $18 million per year until the outstanding amounts on the term credit facilities are repaid.

The following table details contractual maturities for our derivative financial liabilities. The balance sheet amounts for derivative financial liabilities included below are not materially different from the contractual amounts due on maturity.

	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Trading Derivatives (Note 6)	424	225	173	26	–
Non-Trading Derivatives (Note 6)	20	20	–	–	–
Total	444	245	173	26	–

The commercial agreements our energy marketing group enter into often include financial assurance provisions that allow us and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. Based on contracts in place and commodity prices at March 31, 2010, we could be required to post collateral of up to $1,016 million if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral secures the payment of such amounts. In the event of a ratings downgrade, we have trading inventories and receivables that can be quickly monetized as well as undrawn credit facilities.

At March 31, 2010, collateral posted with counterparties includes $5 million of cash and $299 million of letters of credit related to our trading activities. Cash posted is included with our accounts receivable. Cash collateral is not normally applied to contract settlement. Once a contract has been settled, the collateral amounts are refunded. If there is a default, the cash is retained. Our exchange-traded derivative contracts are also subject to margin requirements. We have margin deposits of $178 million (December 31, 2009 – $198 million), which have been included in restricted cash.

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	March 31 **2010**	December 31 **2009**
Energy Marketing Payables	1,422	1,366
Energy Marketing Derivative Contracts (Note 6)	225	456
Accrued Payables	615	619
Trade Payables	245	210
Income Taxes Payable	233	179
Stock-Based Compensation	68	72
Other	276	136
Total	3,084	3,038

9. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

	March 31 **2010**	December 31 **2009**
Canexus Term Credit Facilities, due 2012 (US$244 million drawn) (a)	247	233
Term Credit Facilities, due 2012 (US$1.5 billion drawn) (b)	1,523	1,570
Canexus Notes, due 2013 (US$50 million)	51	52
Notes, due 2013 (US$500 million)	508	523
Canexus Convertible Debentures, due 2014	41	46
Notes, due 2015 (US$250 million)	254	262
Notes, due 2017 (US$250 million)	254	262
Notes, due 2019 (US$300 million)	305	314
Notes, due 2028 (US$200 million)	203	209
Notes, due 2032 (US$500 million)	508	523
Notes, due 2035 (US$790 million)	802	827
Notes, due 2037 (US$1,250 million)	1,270	1,308
Notes, due 2039 (US$700 million)	711	733
Subordinated Debentures, due 2043 (US$460 million)	467	481
	7,144	7,343
Unamortized Debt Issue Costs	(90)	(92)
Total	7,054	7,251

(a) Canexus term credit facilities

Canexus has $450 million (US$444 million) of committed, secured term credit facilities available until 2012. At March 31, 2010, $247 million (US$244 million) was drawn on these facilities (December 31, 2009 – $233 million (US$223 million)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans or US-dollar base rate loans. Interest is payable monthly at floating rates. The term credit facilities are secured by a floating charge debenture over all of Canexus' assets. The credit facility also contains covenants with respect to certain financial ratios of Canexus. The weighted-average interest rate on the Canexus term credit facilities was 1.5% for the three months ended March 31, 2010 (three months ended March 31, 2009 – 2.7%).

(b) Term credit facilities

We have unsecured term credit facilities of $3.1 billion (US$3.1 billion) available until 2012. At March 31, 2010, $1.5 billion (US$1.5 billion) was drawn on these facilities (December 31, 2009 – $1.6 billion (US$1.5 billion)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. The weighted-average interest rate on our term credit facilities was 0.9% for the three months ended March 31, 2010 (three months ended March 31, 2009 – 1.1%). At March 31, 2010, $391 million (US$385 million) of these facilities were utilized to support outstanding letters of credit (December 31, 2009 – $407 million (US$389 million)).

(c) Interest expense

	Three Months Ended March 31	
	2010	**2009**
Long-Term Debt	94	89
Other	4	5
Total	98	94
Less: Capitalized	(18)	(26)
Total	80	68

Capitalized interest relates to and is included as part of the cost of our oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings.

(d) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately $466 million (US$459 million), none of which were drawn at March 31, 2010 (December 31, 2009 – nil). We utilized $116 million (US$114 million) of these facilities to support outstanding letters of credit at March 31, 2010 (December 31, 2009 – $86 million (US$82 million)). Interest is payable at floating rates.

10. CAPITAL MANAGEMENT

Our objectives and processes for managing our capital structure are consistent with those in place at December 31, 2009. Our capital consists of equity, short-term borrowings, long-term debt and cash and cash equivalents as follows:

	March 31	December 31
	2010	**2009**
Net Debt [1]		
Long-Term Debt	7,054	7,251
Less: Cash and Cash Equivalents	(1,997)	(1,700)
Total	5,057	5,551
Equity [2]	7,827	7,646

[1] Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.
[2] Equity is the historical issue of equity and accumulated retained earnings.

We monitor the leverage in our capital structure by reviewing the ratio of net debt to adjusted cash flow (cash flow from operating activities before changes in non-cash working capital and other) and interest coverage ratios at various commodity prices. Net debt and adjusted cash flow are non-GAAP measures that are unlikely to be comparable to similar measures presented by others. We calculate net debt using the GAAP measures of long-term debt and short-term borrowings less cash and cash equivalents (excluding restricted cash).

We use the ratio of net debt to adjusted cash flow as a key indicator of our leverage and to monitor the strength of our balance sheet. For the twelve months ended March 31, 2010, the net debt to adjusted cash flow was 2.2 times compared to 2.5 times at December 31, 2009. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher or lower depending on commodity price volatility, when we are in the investment cycle, or when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we assess whether we need to develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Our interest coverage ratio monitors our ability to fund the interest requirements associated with our debt. Our interest coverage increased from 8.5 times at the end of 2009 to 8.9 times at March 31, 2010. Interest coverage is calculated by dividing our adjusted EBITDA by interest expense before capitalized interest. Adjusted EBITDA is a non-GAAP measure that is calculated using net income excluding interest expense, provision for income taxes, exploration expenses, DD&A, impairment and other non-cash expenses. The calculation of adjusted EBITDA is set out in the following table and is unlikely to be comparable to similar measures presented by others.

	Twelve Months Ended March 31 **2010**	Year Ended December 31 **2009**
Net Income Attributable to Nexen Inc.	586	536
Add:		
Interest Expense	324	312
Provision for Income Taxes	388	260
Depreciation, Depletion, Amortization and Impairment	1,781	1,802
Exploration Expense	342	302
Recovery of Non-Cash Stock-Based Compensation	(11)	(10)
Change in Fair Value of Crude Oil Put Options	251	251
Other Non-Cash Expenses	(153)	(136)
Adjusted EBITDA	3,508	3,317

11. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our Property, Plant & Equipment (PP&E) are as follows:

	Three Months Ended March 31 **2010**	Year Ended December 31 **2009**
Balance at Beginning of Period	1,053	1,059
Obligations Incurred with Development Activities	7	27
Obligations Settled	(11)	(42)
Accretion Expense	17	70
Revisions to Estimates	(32)	13
Effects of Changes in Foreign Exchange Rate	(38)	(74)
Balance at End of Period [1, 2]	996	1,053

[1] Obligations due within 12 months of $64 million (December 31, 2009 – $35 million) have been included in accounts payable and accrued liabilities.

[2] Obligations relating to our oil and gas activities amount to $962 million (December 31, 2009 – $1,002 million) and obligations relating to our chemicals business amount to $34 million (December 31, 2009 – $51 million).

Our total estimated undiscounted inflated asset retirement obligations amount to $2,261 million (December 31, 2009 – $2,341 million). We discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted, risk-free rate of 5.9%. Approximately $298 million included in our asset retirement obligations is expected to be settled over the next five years. The remaining obligations settle beyond five years and are expected to be funded by future cash flows from our operations.

12. DEFERRED CREDITS AND OTHER LIABILITIES

	March 31 **2010**	December 31 **2009**
Deferred Tax Credit	460	503
Long-Term Energy Marketing Derivative Contracts (Note 6)	199	212
Defined Benefit Pension Obligations	75	76
Capital Lease Obligations	60	61
Deferred Transportation Revenue	52	55
Other	113	114
Total	959	1,021

13. SHAREHOLDERS' EQUITY

Dividends

Dividends per common share for the three months ended March 31, 2010 were $0.05 per common share (2009 – $0.05). Dividends paid to holders of common shares have been designated as "eligible dividends" for Canadian tax purposes.

14. MARKETING AND OTHER INCOME

	Three Months Ended March 31	
	2010	**2009**
Marketing Revenue, Net	86	267
Long Lake Purchased Bitumen Sales	28	–
Change in Fair Value of Crude Oil Put Options	(16)	(16)
Interest	4	2
Foreign Exchange Gains	34	19
Other	15	(15)
Total	151	257

15. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share using net income divided by the weighted-average number of common shares outstanding. We calculate diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

	Three Months Ended March 31	
(millions of shares)	**2010**	**2009**
Weighted-average number of common shares outstanding	523.6	520.2
Shares issuable pursuant to tandem options	6.3	7.6
Shares notionally purchased from proceeds of tandem options	(4.8)	(5.1)
Weighted-average number of diluted common shares outstanding	525.1	522.7

In calculating the weighted-average number of diluted common shares outstanding for the three months ended March 31, 2010, we excluded 16,476,455 tandem options, because their exercise price was greater than the average common share market price in the period. In calculating the weighted-average number of diluted common shares outstanding for the three months ended March 31, 2009, we excluded 4,103,560 tandem options, because their exercise price was greater than the average common share market price in the period. During the periods presented, outstanding tandem options were the only potential dilutive instruments.

16. COMMITMENTS, CONTINGENCIES AND GUARANTEES

As described in Note 15 to the Audited Consolidated Financial Statements included in our 2009 Form 10-K, there are a number of lawsuits and claims pending, the ultimate results of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. We continue to believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

During the quarter, we sold our European gas and power marketing business. We agreed to maintain our parental guarantees to the existing counterparties until the purchaser is able to replace them. The guarantees expire at the earlier of the purchaser replacing the guarantees and July 25, 2010. We are obligated to perform under the guarantees only if the purchaser does not meet its obligations to the counterparties. Our total exposure is $275 million for which the purchaser has provided us with an indemnity and a letter of credit from a highly rated financial institution.

17. CASH FLOWS

(e) Charges and credits to income not involving cash

	Three Months Ended March 31	
	2010	**2009**
Depreciation, Depletion, Amortization and Impairment	388	409
Stock-Based Compensation	(1)	–
Loss (Gains) on Disposition of Assets	3	(7)
Recovery of Future Income Taxes	(100)	(87)
Change in Fair Value of Crude Oil Put Options	16	16
Foreign Exchange	(41)	(13)
Other	–	1
Total	265	319

(f) Changes in non-cash working capital

	Three Months Ended March 31	
	2010	**2009**
Accounts Receivable	(218)	298
Inventories and Supplies	113	(49)
Other Current Assets	73	(8)
Accounts Payable and Accrued Liabilities	385	185
Other Current Liabilities	(9)	13
Total	344	439
Relating to:		
Operating Activities	256	420
Investing Activities	88	19
Total	344	439

(g) Other cash flow information

	Three Months Ended March 31	
	2010	**2009**
Interest Paid	103	81
Income Taxes Paid	207	34

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of $12 million for the three months ended March 31, 2010 (2009 – $12 million).

18. SUBSEQUENT EVENTS

In April 2010, we substantially completed negotiations for the sale of our North American natural gas marketing business subject to finalizing documentation and customary closing conditions. We expect to sign the agreement in the second quarter and close the sale in the third quarter. The sale is expected to be cash neutral and we expect to recognize a non-cash loss on the sale of between $250 and $290 million. This loss primarily relates to the transfer of long-term natural gas physical transportation commitments that are less valuable with increased gas supplies that reduce the need for transport services. Although volatile on a quarterly basis, we have had success with our marketing business over the last 10 years generating about $800 million of cash.

19. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen is involved in activities relating to Oil and Gas, Energy Marketing and Chemicals in various geographic locations as described in Note 20 to the Audited Consolidated Financial Statements included in our 2009 Form 10-K.

Three months ended March 31, 2010

	Oil and Gas						Energy Marketing	Chemicals	Corporate and Other	Total
	United Kingdom	Canada	Syncrude	United States	Yemen	Other Countries [1]				
Net Sales	755	180	134	113	182	15	9	113	–	1,501
Marketing and Other	5	28	1	–	5	–	83	7	22 [2]	151
Total Revenues	760	208	135	113	187	15	92	120	22	1,652
Less: Expenses										
Operating	77	134	67	22	41	1	10	70	–	422
Depreciation, Depletion, Amortization and Impairment	168	80	13	64	35	2	5	11	10	388
Transportation and Other	(1)	56	7	2	3	–	123	12	–	202
General and Administrative [3]	13	16	–	11	1	8	21	8	40	118
Exploration	24	7	–	16	–	46 [4]	–	–	–	93
Interest	–	–	–	–	–	–	–	1	79	80
Income (Loss) before Income Taxes	479	(85)	48	(2)	107	(42)	(67)	18	(107)	349
Less: Provision for (Recovery of) Income Taxes	240	(21)	12	(1)	37	(38)	(23)	4	(51)	159
Less: Non-Controlling Interests	–	–	–	–	–	–	–	5	–	5
Net Income (Loss)	**239**	**(64)**	**36**	**(1)**	**70**	**(4)**	**(44)**	**9**	**(56)**	**185**
Identifiable Assets	**4,696**	**7,848 [5]**	**1,292**	**1,717**	**257**	**1,141**	**2,588 [6]**	**701**	**2,523**	**22,763**
Capital Expenditures										
Development and Other	88	70	19	15	10	91	9	49	6	357
Exploration	41	68	–	49	–	41	–	–	–	199
Total	**129**	**138**	**19**	**64**	**10**	**132**	**9**	**49**	**6**	**556**
Property, Plant and Equipment										
Cost	6,027	9,781	1,482	3,828	2,397	991	265	1,164	377	26,312
Less: Accumulated DD&A	2,745	2,108	281	2,504	2,286	97	88	570	252	10,931
Net Book Value	**3,282**	**7,673 [5]**	**1,201**	**1,324**	**111**	**894**	**177**	**594**	**125**	**15,381**

[1] Includes results of operations from producing activities in Colombia.
[2] Includes interest income of $4 million, foreign exchange gains of $34 million and a decrease in the fair value of crude oil put options of $16 million.
[3] Includes stock-based compensation expense of $2 million.
[4] Includes exploration activities primarily in Nigeria, Norway and Colombia.
[5] Includes costs of $6,088 million related to our insitu oil sands (Long Lake and future phases).
[6] Approximately 79% of Marketing's identifiable assets are accounts receivable and inventories.

Three months ended March 31, 2009

	Oil and Gas						Energy Marketing	Chemicals	Corporate and Other	Total
	United Kingdom	Canada	Syncrude	United States	Yemen	Other Countries [1]				
Net Sales	478	91	98	63	162	19	13	124	–	1,048
Marketing and Other	4	7	–	–	3	–	267	(14)	(10) [2]	257
Total Revenues	482	98	98	63	165	19	280	110	(10)	1,305
Less: Expenses										
Operating	51	41	66	23	47	2	8	67	–	305
Depreciation, Depletion, Amortization and Impairment	193	63	11	68	41	5	4	12	12	409
Transportation and Other	(3)	3	7	13	3	–	162	10	6	201
General and Administrative	2	14	–	14	4	8	23	9	26	100
Exploration	8	21	–	10	–	14 [3]	–	–	–	53
Interest	–	–	–	–	–	–	–	2	66	68
Income (Loss) before Income Taxes	231	(44)	14	(65)	70	(10)	83	10	(120)	169
Less: Provision for (Recovery of) Income Taxes	86	(11)	4	(23)	24	(6)	35	2	(80)	31
Less: Non-Controlling Interests	–	–	–	–	–	–	–	3	–	3
Net Income (Loss)	**145**	**(33)**	**10**	**(42)**	**46**	**(4)**	**48**	**5**	**(40)**	**135**
Identifiable Assets	**6,403**	**7,678 [4]**	**1,212**	**2,100**	**400**	**807**	**3,035 [5]**	**594**	**1,390**	**23,619**
Capital Expenditures										
Development and Other	149	244	17	42	29	58	8	36	1	584
Exploration	28	94	–	26	–	15	–	–	–	163
Proved Property Acquisitions	–	757	–	–	–	–	–	–	–	757
Total	**177**	**1,095**	**17**	**68**	**29**	**73**	**8**	**36**	**1**	**1,504**
Property, Plant and Equipment										
Cost	6,869	9,225	1,386	4,591	2,920	636	256	983	332	27,198
Less: Accumulated DD&A	2,419	1,843	244	2,850	2,729	121	80	523	212	11,021
Net Book Value	**4,450**	**7,382 [4]**	**1,142**	**1,741**	**191**	**515**	**176**	**460**	**120**	**16,177**

[1] Includes results of operations from producing activities in Colombia.
[2] Includes interest income of $2 million, foreign exchange gains of $19 million, decrease in the fair value of crude oil put options of $16 million and other losses of $15 million.
[3] Includes exploration activities primarily in Norway and Colombia.
[4] Includes costs of $5,658 million related to our insitu oil sands (Long Lake and future phases).
[5] Approximately 77% of Marketing's identifiable assets are accounts receivable and inventories.

20. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Unaudited Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. The US GAAP Unaudited Consolidated Statements and summaries of differences from Canadian GAAP are as follows:

Unaudited Consolidated Statement of Income – US GAAP
For the Three Months Ended March 31

(Cdn$ millions, except per share amounts)	2010	2009
Revenues and Other Income		
Net Sales	1,501	1,048
Marketing and Other (v); (vi)	205	292
	1,706	1,340
Expenses		
Operating	422	305
Depreciation, Depletion, Amortization and Impairment	388	409
Transportation and Other (v)	205	194
General and Administrative (iv)	126	108
Exploration	93	53
Interest	80	68
	1,314	1,137
Income before Provision for Income Taxes	392	203
Provision for (Recovery of) Income Taxes		
Current	259	118
Deferred (iv); (vi); (vii)	(86)	(74)
	173	44
Net Income – US GAAP	219	159
Less: Net Income Attributable to Non-Controlling Interests	5	3
Net Income Attributable to Nexen Inc. – US GAAP [1]	214	156
Earnings Per Common Share ($/share) (Note 15)		
Basic	0.41	0.30
Diluted	0.41	0.30

[1] **Reconciliation of Canadian and US GAAP Net Income**

	Three Months Ended March 31	
	2010	**2009**
Net Income Attributable to Nexen Inc – Canadian GAAP	185	135
Impact of US Principles, Net of Income Taxes:		
Stock-based Compensation (iv)	(6)	–
Inventory Valuation (vi)	35	(6)
Deferred Taxes (vii)	–	27
Net Income Attributable to Nexen Inc – US GAAP	214	156

Unaudited Consolidated Balance Sheet – US GAAP

(Cdn$ millions, except share amounts)	March 31 **2010**	December 31 **2009**
Assets		
Current Assets		
Cash and Cash Equivalents	1,997	1,700
Restricted Cash	178	198
Accounts Receivable	2,635	2,788
Inventories and Supplies (vi)	555	610
Other	102	185
Total Current Assets	5,467	5,481
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $11,324 (December 31, 2009 - $11,200) (i); (iii)	15,332	15,443
Goodwill	330	339
Deferred Income Tax Assets	1,238	1,148
Deferred Charges and Other Assets	328	370
Total Assets	22,695	22,781
Liabilities		
Current Liabilities		
Accounts Payable and Accrued Liabilities (iv)	3,185	3,131
Accrued Interest Payable	77	89
Dividends Payable	26	26
Total Current Liabilities	3,288	3,246
Long-Term Debt	7,054	7,251
Deferred Income Tax Liabilities (i); (ii); (iv); (vi); (vii)	2,727	2,720
Asset Retirement Obligations	932	1,018
Deferred Credits and Other Liabilities (ii)	1,064	1,126
Equity		
Nexen Inc. Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2010 – 524,046,867 shares		
2009 – 522,915,843 shares	1,076	1,049
Contributed Surplus	–	1
Retained Earnings (i); (ii); (iv); (vi); (vii)	6,763	6,575
Accumulated Other Comprehensive Loss (ii)	(280)	(269)
Total Nexen Inc. Shareholders' Equity	7,559	7,356
Canexus Non-Controlling Interests	71	64
Total Equity	7,630	7,420
Commitments, Contingencies and Guarantees (Note 16)		
Total Liabilities and Equity	22,695	22,781

Unaudited Consolidated Statement of Comprehensive Income – US GAAP
For the Three Months Ended March 31

	Three Months Ended March 31 **2010**	**2009**
Net Income Attributable to Nexen Inc. – US GAAP	214	156
Other Comprehensive Income (Loss), Net of Income Taxes:		
Foreign Currency Translation Adjustment	(11)	6
Comprehensive Income Attributable to Nexen Inc. – US GAAP	203	162

Unaudited Consolidated Statement of Accumulated Other Comprehensive Loss – US GAAP

	March 31 **2010**	December 31 **2009**
Foreign Currency Translation Adjustment	(201)	(190)
Unamortized Defined Benefit Pension Plan Costs (ii)	(79)	(79)
Accumulated Other Comprehensive Loss	(280)	(269)

Notes to the Unaudited Consolidated US GAAP Financial Statements:

i. Under Canadian GAAP, we defer certain development costs to PP&E. Under US principles, these costs have been included in operating expenses in prior years. As a result, PP&E is lower under US GAAP by $30 million (December 31, 2009 – $30 million) and deferred income tax liabilities are lower by $11 million (December 31, 2009 – $11 million).

ii. US GAAP requires the recognition of the over-funded and under-funded status of a defined benefit plan on the balance sheet as an asset or liability. At March 31, 2010 and December 31, 2009, the unfunded amount of our defined benefit pension plans that was not included in the pension liability under Canadian GAAP was $105 million. This amount has been included in deferred credits and other liabilities and $79 million, net of income taxes, has been included in Accumulated Other Comprehensive Income (AOCI).

iii. On January 1, 2003, we adopted *Accounting for Asset Retirement Obligations* for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent except for the adoption date which results in our PP&E under US GAAP being lower by $19 million.

iv. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. In addition, under Canadian principles, we retroactively adopted EIC-162 which requires the accelerated recognition of stock-based compensation expense for all stock-based awards made to our retired and retirement-eligible employees. However, US GAAP requires the accelerated recognition of stock-based compensation expense for such employees for awards granted on or after January 1, 2006. As a result under US GAAP:

- general and administrative (G&A) expense is higher by $8 million, ($6 million, net of income taxes), for the three months ended March 31, 2010, (2009 – higher by $8 million ($6 million, net of income taxes)); and
- accounts payable and accrued liabilities are higher by $101 million as at March 31, 2010 (December 31, 2009 – $93 million).

v. Under US GAAP, asset disposition gains and losses are included with transportation and other expense. Losses of $3 million for the three months ended March 31, 2010, were reclassified from marketing and other income to transportation and other expense (gains of $7 million were reclassified for the three months ended March 31, 2009).

vi. Under Canadian GAAP, we carry our commodity inventory held for trading purposes at fair value, less any costs to sell. Under US GAAP, we are required to carry this inventory at the lower of cost or net realizable value. As a result:

- marketing and other income is higher by $51 million ($35 million, net of income taxes) for the three months ended March 31, 2010 (2009 – higher by $42 million ($27 million, net of income taxes)); and
- inventories are lower by $19 million as at March 31, 2010 (December 31, 2009 – lower by $70 million) and deferred income tax liabilities are $7 million lower (December 31, 2009 – lower by $23 million).

vii. Under US GAAP, we are required to apply FIN48 *Accounting for Uncertainty in Income Taxes* regarding accounting and disclosure for uncertain tax positions.

As at March 31, 2010, the total amount of our unrecognized tax benefit was approximately $279 million, all of which, if recognized, would affect our effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the Unaudited Consolidated Statement of Income. As at March 31, 2010, the total amount of interest and penalties related to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP – Unaudited Consolidated Balance Sheet was approximately $8 million. We had no

interest or penalties included in the US GAAP – Unaudited Consolidated Statement of Income for the three months ended March 31, 2010.

Our income tax filings are subject to audit by taxation authorities and as at March 31, 2010 the following tax years remained subject to examination, (i) Canada – 1985 to date (ii) United Kingdom – 2008 to date and (iii) United States – 2005 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next 12 months.

New Accounting Pronouncements – US GAAP

In January 2010, the Financial Accounting Standards Board issued guidance to improve fair value measurement disclosures. The guidance requires entities to describe transfers between the three levels of the fair value hierarchy and present items separately in the level 3 reconciliation. This guidance is consistent with fair value measurement disclosures adopted for Canadian GAAP in 2009. Adoption of this guidance did not have an impact on our results of operations or financial position.

Nexen Inc.
Oil and Gas Prices and Cash Netback [1]

(all dollar amounts in Cdn$ unless noted)	Quarters – 2010 1st	Quarters – 2009 1st	2nd	3rd	4th	Total Year 2009
PRICES:						
WTI Crude Oil (US$/bbl)	78.71	43.08	59.62	68.30	76.19	61.80
Nexen Average – Oil (Cdn$/bbl)	78.00	50.41	68.32	72.95	76.39	66.85
NYMEX Natural Gas (US$/mmbtu)	5.04	4.48	3.81	3.44	4.91	4.16
Nexen Average – Gas (Cdn$/mcf)	5.37	5.11	3.77	3.04	4.31	4.06
NETBACKS:						
United Kingdom						
Crude Oil:						
Sales (mbbls/d)	106.5	100.8	97.0	70.4	119.6	96.9
Price Received ($/bbl)	77.25	51.60	69.42	73.15	76.40	67.70
Natural Gas:						
Sales (mmcf/d)	33	21	17	17	43	24
Price Received ($/mcf)	4.81	5.50	3.67	2.64	3.82	3.95
Total Sales Volume (mboe/d)	112.1	104.3	99.8	73.2	126.8	101.0
Price Received ($/boe)	74.84	50.97	68.10	70.95	73.39	65.93
Operating Costs	7.60	5.48	5.85	10.34	6.77	6.87
Netback	67.24	45.49	62.25	60.61	66.62	59.06
Canada – Heavy Oil & Bitumen [2]						
Sales (mbbls/d)	22.62	15.4	14.7	14.0	13.5	14.4
Price Received ($/bbl)	71.24	35.35	56.05	59.88	62.53	53.04
Royalties & Other	10.27	6.86	12.83	13.47	14.07	11.70
Operating & Other Costs [3]	67.57	15.42	16.41	16.21	16.73	16.17
Netback	(6.60)	13.07	26.81	30.20	31.73	25.17
Canada – Natural Gas						
Sales (mmcf/d)	124	137	134	136	130	134
Price Received ($/mcf)	5.02	4.75	3.42	2.85	4.14	3.78
Royalties & Other	0.40	0.59	0.15	0.21	0.34	0.32
Operating Costs	1.70	1.54	1.59	1.82	2.10	1.76
Netback	2.92	2.62	1.68	0.82	1.70	1.70
Syncrude						
Sales (mbbls/d)	19.5	19.8	14.9	22.5	23.7	20.2
Price Received ($/bbl)	83.55	55.48	71.58	74.54	79.83	70.96
Royalties & Other	7.09	0.40	8.84	8.31	6.75	6.04
Operating Costs	38.43	36.95	57.21	29.50	27.93	35.92
Netback	38.03	18.13	5.53	36.73	45.15	29.00

[1] Defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen.
[2] 2010 includes results from our start up activities at Long Lake.
[3] 2010 Includes Long Lake third-party bitumen purchases.

Nexen Inc.
Oil and Gas Cash Netback [1] (continued)

(all dollar amounts in Cdn$ unless noted)	Quarters – 2010 1st	Quarters – 2009 1st	2nd	3rd	4th	Total Year 2009
United States						
Crude Oil:						
Sales (mbbls/d)	9.8	10.4	12.1	9.5	10.0	10.5
Price Received ($/bbl)	79.12	46.27	66.23	72.27	75.75	65.01
Natural Gas:						
Sales (mmcf/d)	101	50	61	63	84	65
Price Received ($/mcf)	6.00	5.93	4.58	3.56	4.83	4.67
Total Sales Volume (mboe/d)	26.60	18.8	22.2	20.0	23.9	21.2
Price Received ($/boe)	51.92	41.50	48.53	45.43	48.55	46.27
Royalties & Other	4.92	4.52	4.94	4.77	5.21	4.89
Operating Costs	8.96	13.79	13.11	12.40	11.32	12.58
Netback	38.04	23.19	30.48	28.26	32.02	28.80
Yemen						
Sales (mbbls/d)	47.3	54.7	51.4	43.2	46.2	48.8
Price Received ($/bbl)	80.39	52.30	69.40	76.31	78.93	68.49
Royalties & Other	37.52	19.43	31.94	32.08	33.71	28.94
Operating Costs	9.67	9.62	10.39	12.43	10.62	10.69
In-country Taxes	10.14	4.92	9.01	9.70	10.17	8.31
Netback	23.06	18.33	18.06	22.10	24.43	20.55
Other Countries						
Sales (mbbls/d)	2.3	5.5	3.6	2.6	2.4	3.5
Price Received ($/bbl)	78.88	41.68	66.83	70.49	74.10	59.05
Royalties & Other	5.72	3.26	5.17	5.38	5.48	4.52
Operating Costs	5.58	4.81	5.73	5.70	9.52	6.03
Netback	67.58	33.61	55.93	59.41	59.10	48.50
Company-Wide						
Oil and Gas Sales (mboe/d)	251.1	241.4	228.9	198.2	258.1	231.6
Price Received ($/boe)	70.16	47.56	61.28	63.00	68.04	60.02
Royalties & Other	9.32	5.64	9.23	9.58	8.09	8.06
Operating & Other Costs [2]	16.14	10.62	11.95	13.60	10.86	11.66
In-country Taxes	1.91	1.11	2.02	2.11	1.82	1.75
Netback	42.79	30.19	38.08	37.71	47.27	38.55

[1] Defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen.
[2] 2010 includes Long Lake third-party bitumen purchases.

Nexen Inc.
Production Volumes (before royalties) [1]

	Three Months Ended March 31	
	2010	**2009**
Crude Oil and Liquids (mbbls/d)		
United Kingdom	105.6	103.8
Canada	14.2	15.5
Long Lake Bitumen	12.1	8.1
Syncrude	19.5	19.8
United States	9.8	10.4
Yemen	42.8	54.5
Other Countries	2.3	5.5
	206.3	217.6
Natural Gas (mmcf/d)		
United Kingdom	40	18
Canada	133	137
United States	101	50
	274	205
Total Production (mboe/d)	252	252

Production Volumes (after royalties)

	Three Months Ended March 31	
	2010	**2009**
Crude Oil and Liquids (mbbls/d)		
United Kingdom	105.6	103.8
Canada	11.0	12.3
Long Lake Bitumen	11.3	8.1
Syncrude	17.8	19.6
United States	8.9	9.5
Yemen	23.1	35.7
Other Countries	2.1	5.1
	179.8	194.1
Natural Gas (mmcf/d)		
United Kingdom	40	18
Canada	121	122
United States	88	45
	249	185
Total Production (mboe/d)	221	225

[1] We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

Cash Flow from Operations [1]

(Cdn$ millions)	Three Months Ended March 31 2010	2009
Oil & Gas		
United Kingdom	671	430
Canada	60	34
Long Lake	(58)	–
Syncrude	60	26
United States	78	12
Yemen [2]	99	87
Other Countries	6	9
Marketing	(59)	84
	857	682
Chemicals	22	27
	879	709
Interest and Other Corporate Items	(125)	(58)
Income Taxes [3]	(216)	(94)
Cash Flow from Operations [1]	538	557

[1] Defined as cash flow from operating activities before changes in non-cash working capital and other. We evaluate our performance and that of our business segments based on earnings and cash flow from operations. Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other and excludes items of a non-recurring nature. We consider it a key measure as it demonstrates our ability and the ability of our business segments to generate the cash flow necessary to fund future growth through capital investment and repay debt. Cash flow from operations may not be comparable with the calculation of similar measures for other companies.

(Cdn$ millions)	Three Months Ended March 31 2010	2009
Cash Flow from Operating Activities	798	789
Changes in Non-Cash Working Capital	(256)	(420)
Other	6	141
Impact of Annual Crude Oil Put Options	(10)	47
Cash Flow from Operations	538	557
Weighted-average Number of Common Shares Outstanding (millions of shares)	523.6	520.2
Cash Flow from Operations Per Common Share ($/share)	1.03	1.07

[2] After in-country cash taxes of $43 million for the three months ended March 31, 2010 (2009 – $24 million).

[3] Excludes in-country cash taxes in Yemen.

CORPORATE INFORMATION

OFFICERS

Francis M. Saville, Q.C.
Chair of the Board

Marvin F. Romanow
President and
Chief Executive Officer

Kevin J. Reinhart
Executive Vice President
and Chief Financial Officer

Gary H. Nieuwenburg
Executive Vice President, Canada

Matthew J. Fox
Executive Vice President,
International

Brian C. Reinsborough
Senior Vice President,
United States Oil and Gas

James T. Arnold
Senior Vice President,
Synthetic Crude

Eric B. Miller
Senior Vice President, General
Counsel and Secretary

Una M. Power
Senior Vice President, Corporate
Planning and Business Development

Catherine J. Hughes
Vice President,
Operational Services, Technology
and Human Resources

Kim D. McKenzie
Vice President and Chief Information
Officer

Kevin J. McLachlan
Vice President, Exploration

Brendon T. Muller
Controller

J. Michael Backus
Treasurer

Rick C. Beingessner
Assistant Secretary

C. James Cummings
Assistant Secretary

DIRECTORS

William B. Berry

Robert G. Bertram

Dennis G. Flanagan

S. Barry Jackson

Kevin J. Jenkins

The Hon. A. Anne McLellan, P.C.

Eric P. Newell, O.C.

Thomas C. O'Neill

Marvin F. Romanow

Francis M. Saville, Q.C.

John M. Willson

Victor J. Zaleschuk

For more information on our officers and directors, please see Item 10 in our Form 10-K or visit www.nexeninc.com.

WEBSITE

Nexen's statistical supplement and other financial documents are available online at www.nexeninc.com.

Hard copies may be ordered via the Investor section of our website or by calling 403.699.5931.

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STOCK SYMBOL: NXY

Toronto Stock Exchange
New York Stock Exchange

SUBORDINATED NOTES

7.35% due 2043
TSX: NXY.PR.U
NYSE: NXYPRB

DIVIDEND REINVESTMENT PLAN

A copy of the offering circular (and for United States residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or on the internet at www.cibcmellon.com

AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

INVESTOR RELATIONS CONTACT

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