

# MANAGEMENT'S DISCUSSION AND ANALYSIS



Nexen's Long Lake oil sands facility

## Management's Discussion and Analysis

Executive Summary	69
Capital Investment	72
Financial Results	76
Oil & Gas	77
Oil & Gas Netbacks	88
Energy Marketing	89
Chemicals	92
Corporate Expenses	93
Summary of Quarterly Results	96
Outlook for 2011	97
Liquidity and Capital Resources	98
Critical Accounting Estimates	103
New Accounting Pronouncements	106
Quantitative and Qualitative Disclosures about Market Risk	110
Other	114
Forward-Looking Statements	115

# MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

The following should be read in conjunction with the Consolidated Financial Statements of Nexen Inc. as at and for the year ended December 31, 2010. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 24 to the Consolidated Financial Statements. The date of this discussion is February 16, 2011. Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Oil and gas volumes, reserves and related performance measures are 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, we have provided information on an after-royalty basis in tabular format.

Investors should read the "Forward-Looking Statements" on page 115.

Proved and probable reserves estimates included in this MD&A have been prepared in accordance with SEC requirements. Canadian investors should read the "Special Note to Canadian Investors" on page 34 in our AIF for the year ended December 31, 2010.

## EXECUTIVE SUMMARY

### 2010 Results

<i>(Cdn\$ millions, except otherwise indicated)</i>	<b>2010</b>	<b>2009</b>	<b>2008</b>
Production before Royalties (mboe/d) <sup>1,2</sup>	246	243	250
Production after Royalties (mboe/d) <sup>2</sup>	220	213	210
Total Revenues and Other Income <sup>2</sup>	7,226	5,804	8,237
Cash Flow from Operations <sup>2,3</sup>	2,130	2,215	4,229
Net Income from Continuing Operations	572	512	1,602
Net Income <sup>2</sup>	1,197	536	1,715
Earnings per Common Share from Continuing Operations, Basic (\$/share)	1.09	0.98	3.05
Earnings per Common Share from Continuing Operations, Diluted (\$/share)	1.08	0.96	3.01
Earnings per Common Share, Basic <sup>2</sup> (\$/share)	2.28	1.03	3.26
Earnings per Common Share, Diluted <sup>2</sup> (\$/share)	2.27	1.01	3.22
Cash Dividend (\$/share)	0.20	0.20	0.18
Total Assets	21,907	22,900	22,155
Net Debt <sup>4</sup>	4,074	5,551	4,575

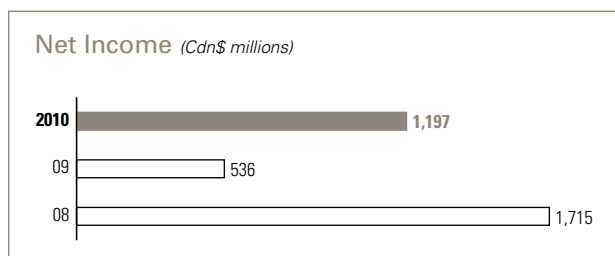
1 Production before royalties reflects our working interest before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies. We report bitumen as production until we are consistently operating the upgrader and producing PSC™.

2 Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).

3 Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 114.

4 Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 114.

Strong production rates and strengthening commodity prices delivered solid financial results in 2010 as cash flow from operations during the year exceeded \$2.1 billion and net income was approximately \$1.2 billion. Our successful non-core asset disposition program generated proceeds of almost \$1.3 billion and net pre-tax gains of \$740 million in 2010. This excludes the sale of our interest in Canexus in early 2011 which generated cash proceeds of \$458 million. We received the Canexus proceeds in February 2011 and we expect to recognize a gain of approximately \$250 to \$300 million in the first quarter of 2011.



WTI and Brent crude oil prices both increased 29% from the previous year to average about US\$80/bbl. The benefit from these higher commodity prices was muted by the stronger Canadian dollar as the US/Canadian average exchange rate strengthened from 88 cents in 2009 to 97 cents this year. Our realized oil and gas price increased 17% over the same period to average \$70.11/boe.

Production before royalties averaged 246,000 boe/d in 2010, up slightly from last year. Excluding the impact from the sale of the heavy oil assets midway through the year, production increased 5% over last year. A full year of production at

Longhorn in the Gulf of Mexico and at Ettrick in the North Sea, and continued bitumen ramp-up at Long Lake, increased production volumes in 2010. UK production was higher than last year despite third-party facilities outages as well as planned downtime to commission the Buzzard fourth platform that temporarily reduced production. Our fourth quarter production averaged 246,000 boe/d, 3% higher than the previous quarter. This increase reflects new production from our Horn River shale gas, improved uptime at Syncrude and growth in the UK. In 2011, we expect production to range between 230,000 and 270,000 boe/d before royalties.

Our financial position is strong. For the past several years, we invested significant capital in a number of major development projects such as Buzzard and Long Lake. With the bulk of investment in these projects behind us and new production from Ettrick, Longhorn and Long Lake on stream, we expect to fund our next generation of new growth projects from operating cash flows. These projects include Golden Eagle in the UK North Sea, Usan offshore West Africa (approximately 85% complete), future oil sands insitu phases and shale gas in the Horn River Basin in northeast British Columbia, as well as several exploration prospects.

Our net debt decreased 25% or approximately \$1.5 billion during the year primarily as a result of our non-core asset disposition program. Net debt was further reduced by \$458 million in early 2011 upon receipt of the proceeds from the Canexus sale.

Our available liquidity is currently \$4 billion, comprised of cash and undrawn committed credit facilities, most of which are available until 2014. The average term-to-maturity of our debt is approximately 21 years.

## Strategy Progress

<i>(Cdn\$ millions)</i>	2010	2009	2008
Oil and Gas Capital Investment, including Acquisitions	2,492	3,303	3,054
Proved Oil and Gas Reserves before Royalties (mmboe) <sup>1</sup>	987	1,011	988
Proved Oil and Gas Reserves after Royalties (mmboe) <sup>1</sup>	903	920	926

<sup>1</sup> Includes developed and undeveloped proved reserves as at December 31.

Our strategy is to build a sustainable energy company focused in three growth areas: oil sands, conventional exploration and development and unconventional gas. Our investment in these areas generated the following results in 2010:

- conventional exploration and development**—our conventional exploration program was focused in the North Sea, deep-water Gulf of Mexico and offshore West Africa. We advanced the development of our Usan field toward first production in 2012. In the UK North Sea we advanced our Golden Eagle/Hobby project by capturing land adjacent to the field, gaining partner support for the development plan and filing a Field Development Plan with the regulatory authority. We also made a significant discovery at Appomattox in the US Gulf of Mexico and several other discoveries around our existing infrastructure in the North Sea.
- oil sands**—we commenced actions to fill the upgrader through accelerated pad drilling, increase steam capacity, enhancing independence between the SAGD and upgrader operations, and increase water-handling capacity. We have also developed a bitumen leading strategy at Kinosis to simplify the development while retaining the option to capture the benefits of upgrading and our integrated process.
- unconventional gas**—we delivered a drilling, fracing and completions program at industry-leading pace with a 100% success rate. We commenced production of the eight-well program and shale gas production is approaching expectations of 50 mmcf/d and is giving us the desired information on well design. We also acquired additional acreage in the Cordova and Liard basins, making us one of the largest acreage holders in this highly attractive area.

During 2010, our proved oil and gas reserves additions replaced 114% of our oil and gas production (135% after royalties).

<i>(mmboe)</i>	Oil and Gas	
	Before Royalties	After Royalties
<b>Production<sup>1</sup></b>	89	79
<b>Proved Reserve Changes excluding Production</b>		
Net Additions	100	94
Economic Revisions	1	13
	101	107

<sup>1</sup> Production for Long Lake is presented in synthetic barrels as our reserves are measured in synthetic oil barrels. For comparative purposes, production volumes before royalties using bitumen barrels would be 90 mmboe before royalties (80 after royalties).

The majority of our additions relate to our exploration successes at Golden Eagle, Rochelle and Blackbird, strong production performance at Buzzard and Telford in the UK and Yemen, and the recognition of shale gas reserves at our Horn River Basin development. During the year, we sold 36 mmboe (30 after royalties) as part of our heavy oil disposition.

Our 2010 proved reserve additions are not necessarily indicative of future annual additions which will be dependent on such factors as oil and gas prices, capital allocations, nature of our drilling programs, exploration success and expected timing of proceeding with development of reserves discovered. Management uses the reserves replacement ratio as a measure for our success in replacing reserves produced. We look at various time periods when considering this ratio.

## Outlook

For 2011, we expect our annual production will range between 230,000 and 270,000 boe/d (210,000 to 240,000 boe/d after royalties). The range is driven by the pace of ramp-up at Long Lake, run-times at Buzzard and Scott/Telford in the North Sea and the timing of new volumes from our Horn River shale gas program. We expect to grow production after royalties by approximately 4% assuming the midpoint of our guidance range and 7% after adjusting for the sale of our heavy oil properties in 2010.

We expect our 2011 cash flow from operations to range from \$2.1 to \$2.8 billion assuming WTI of US\$75 to US\$90/bbl. Since late December 2010, international oil prices have risen faster than WTI with Brent trading at a premium of \$18/bbl. With 80% of our oil production receiving international prices, we expect to see the benefits of this in 2011 as our cash flow sensitivity is \$270 million annually per US\$10/bbl change in Brent, after tax.

In 2011, we plan to invest between \$2.4 and \$2.7 billion in capital projects which we expect to finance through operating cash flows and existing cash on hand. Our capital program is expected to advance our future growth areas as we move forward with developing several major identified projects, including Usan, Golden Eagle, Knotty Head and Horn River shale gas. Our 2011 capital investment plans include investing between \$600 and \$650 million on drilling 22 exploration and appraisal wells, primarily in the North Sea and the Gulf of Mexico.

## CAPITAL INVESTMENT

<i>(Cdn\$ millions)</i>	Estimated 2011	2010	2009
<b>Conventional Development and Exploration</b>			
North Sea	750	766	684
West Africa	500	495	507
United States	250	261	321
Other	50	166 <sup>1</sup>	187
	1,500–1,600	1,688	1,699
<b>Oil Sands</b>			
Long Lake, Kinosis and Other Insitu	425	228	1,303
Syncrude	150	100	87
	550–600	328	1,390
<b>Unconventional Gas</b>	300–350	476	214
<b>Total Oil and Gas</b>	<b>2,350–2,600</b>	<b>2,492</b>	<b>3,303</b>
Corporate, Chemicals and Other	50–100	210	275
<b>Total Capital</b>	<b>2,400–2,700</b>	<b>2,702</b>	<b>3,578</b>

<sup>1</sup> Includes capital in Canada (\$78 million) and Yemen (\$52 million).

Our strategy and capital programs are focused on growing value for our shareholders responsibly. To maximize value, we invest in:

- core assets for short-term production and free cash flow to fund capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow in the medium term; and
- appraisal, exploration and new growth projects for longer-term growth.

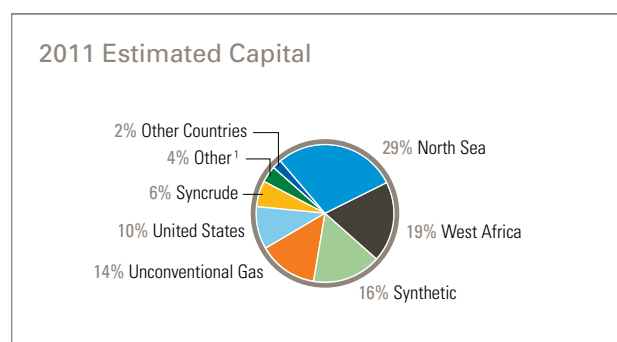
We invest in key focus areas including Athabasca oil sands, Canadian unconventional shale gas, and offshore opportunities in the North Sea, deep-water Gulf of Mexico, and West Africa—areas we believe have attractive fiscal terms, significant remaining opportunity and where we believe we have a competitive advantage.

In 2010, we invested \$2.5 billion in oil and gas activities and added 101 mmbœ of proved reserves and 25 mmbœ of probable reserves before royalties. We are not yet carrying any proved or probable reserves for our discoveries in the Appomattox area, at Knotty Head or at Owowo. A summary of our 2010 capital investment program and reserve additions are shown in the table below. In this section, production and reserves are before royalties. Additional information on our oil and gas reserves can be found in Reserves, Production and Related Information on page 25 of our AIF.

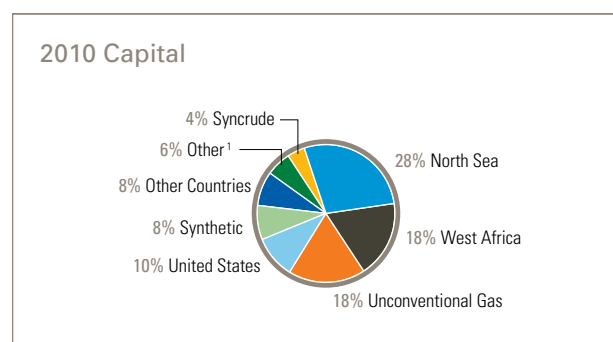
	<b>Capital Investment<sup>1</sup></b> <i>(Cdn\$ millions)</i>	<b>Production<sup>2</sup></b> <i>(mmbœ)</i>	<b>Proved Reserve Additions<sup>2</sup></b> <i>(mmbœ)</i>	<b>Probable Reserve Additions<sup>2</sup></b> <i>(mmbœ)</i>
Conventional Exploration and Production	1,688	76	80	3
Oil Sands	328	12	8	5
Unconventional Gas	476	1	13	17
<b>Total Oil and Gas</b>	<b>2,492</b>	<b>89</b>	<b>101</b>	<b>25</b>

<sup>1</sup> Oil and gas capital investment includes \$100 million of cash outflows related to geological and geophysical expenditures.

<sup>2</sup> Before royalties.



<sup>1</sup> Energy Marketing, Corporate and Other.



<sup>1</sup> Energy Marketing, Corporate and Other.

## Conventional Exploration and Production

### NORTH SEA

We continue to have significant success in the North Sea. Since entering the basin in late 2004, we have gone from 100 million boe of proved reserves to 255 million boe of produced and remaining proved reserves. Buzzard is one of the drivers to this growth. We have continued to find

more oil than originally expected, allowing us to recognize increased reserves, identify further development drilling locations and extend the production plateau for several more years.

In 2010, we invested \$766 million in the North Sea, including \$305 million on exploration and appraisal activities. We drilled successful wells at Polecat and West Rochelle, and a successful follow up to our Blackbird discovery.

At Buzzard, we spent \$80 million to install the topsides and commission the fourth platform. This will enable us to produce our wells with higher H<sub>2</sub>S concentrations. We added 22 million boe of proved reserves here, primarily attributable to successful drilling and production performance which resulted in increases in both reservoir size and recovery factor.

Also during the year, we made significant progress in advancing our discoveries in the Golden Eagle area. We expanded the acreage position to follow the trend to the north. In late 2010, we filed a field development plan with the regulatory authority. Our discoveries are large enough to require standalone facilities and are economic with oil prices significantly lower than current prices. Facility design size is expected to be 70,000 boe/d (gross). Following equalization of the blocks, we will have a 36.5% working interest and will operate the project.

We expect to sanction the development in 2011. To date, we have booked 34 million boe of proved reserves and an additional 16 million boe of probable reserves for this area.

We are also having success with our drilling program centered around our infrastructure. At Scott/Telford, we invested \$150 million and added six million boe of proved reserves from development drilling. We anticipate further upside in the area with opportunities for quick tie-backs. We also added five million boe of proved reserves for Rochelle, a tie-back development to our Scott platform.

During the quarter, the UK Government announced that, subject to completion of the award process, we were the successful applicant for 10 licences covering 18 blocks in the UK North Sea 26th Offshore Oil and Gas Licensing Round. Most of these blocks are near our existing acreage and infrastructure, and are expected to enhance our ongoing exploration program.

#### OFFSHORE WEST AFRICA

We made excellent progress on the development of the Usan field, offshore West Africa, and remain on track to achieve first oil in 2012. The development includes a floating production, storage and offloading vessel (FPSO) with the ability to process 180,000 bbls/d (36,000 net to us) and store up to two million barrels of oil. FPSO fabrication is nearing completion and the vessel will soon be towed to Nigeria for field installation. The project is approximately 85%

complete and is expected to generate \$850 million of net annual cash flow at WTI US\$90/bbl. We have a 20% interest in exploration and development on this block along with partners ExxonMobil, Chevron and operator Total E&P Nigeria Limited.

#### UNITED STATES

In the Gulf of Mexico, our capital program is focused on the deep-water and in 2010 we invested \$178 million on exploration and appraisal, and \$83 million on our deep-water and shelf producing assets.

Our exploration program resulted in a discovery at Appomattox, located in Mississippi Canyon blocks 391 and 392. An exploration well and two appraisal sidetracks have confirmed this to be a significant oil discovery. We plan to further appraise this discovery once drilling permits are received.

Elsewhere in the deep-water, we drilled an appraisal well at Knotty Head and the joint venture participants have entered into a letter of intent to unitize the field with Hess' Pony discovery. We are working on having an integrated project team in place later in 2011 to work on a joint development plan to move the Knotty Head and Pony discoveries towards sanctioning. As we advance our development concept, we expect to book reserves here.

We are waiting on drilling permits from the Bureau of Ocean Energy Management (BOEM) to drill two exploration prospects, Kakuna and Angel Fire, in the area near our Knotty Head discovery. We have negotiated a reduced standby rate on one of our rigs and have declared force majeure on the other. The estimated maximum 2011 cost to us for these costs is \$65 million, assuming we cannot commence drilling until the end of the second quarter. We are actively pursuing ways to reduce this cost.

Early in 2010, we initiated a process to market a portion of our Gulf of Mexico exploration portfolio including the farm-down of higher working interest prospects. With the Macondo incident, we focused on farm-outs on a well-by-well basis of our near-term drilling prospects. Negotiations with several parties are underway and are expected to be completed before the wells commence drilling.

## YEMEN

In 2010, we invested \$52 million and added 6 million boe of proved reserves. We continue to focus on maximizing the value of these assets over the remaining life of the contracts. We are currently in discussions with the Yemen government on a contract extension.

## Oil Sands

We invested \$228 million on the Long Lake project and other joint venture lands. The focus of the capital has been on the electric submersible pump (ESP) installation program, activities to increase production and reliability at Long Lake, advancing Kinosis and on our other future oil sands developments.

Ongoing initiatives to support the ramp-up at Long Lake include accelerated drilling of pads 12 and 13 which will be ready for steaming in 2012; the addition of two once-through steam generators that will add 10 to 15% to our existing steam capacity and be ready for service late 2012; and creating greater independence between the SAGD operations and upgrader by increasing gas inlet capacity and adding a diluent recovery unit. These investments represent \$400 to \$500 million of capital (net to us), over the next few years, of which approximately half relates to the additional pads and represents an acceleration of capital spending.

We are also advancing engineering activities on Kinosis to develop two 40,000 bbl/d SAGD projects. This development plan provides us with the option to add an upgrader when SAGD projects are ramped up to capacity.

We are monitoring our partner's financial status and assessing their capabilities to continue funding their share of the capital spending. As the potential for this type of situation was contemplated at the time we entered into the joint venture we believe our interests are well protected.

## Unconventional Gas

We made considerable progress in advancing our northeast BC shale gas play. We successfully drilled and brought on-stream our eight-well pad, and commenced drilling another nine-well pad late in the year. We more than doubled our acreage position to 300,000 acres (100% working interest), making us one of the largest leaseholders in this attractive play.

We invested in the drilling, completion and tie-in of the eight-well pad and expansion of in-field facilities. The drilling campaign was completed in under 25 days per well. Compared to our previous program, these wells were drilled in 35% fewer days and were 80% longer. These wells were completed with 18 fracs per well at an industry-leading pace of 3.5 fracs per day with a 100% success rate. We recently started producing these wells and are experiencing initial production rates of 8 to 15 mmcf/d per well. With the success we're seeing on our activities, we expect to be able to make a 10% return with NYMEX gas prices as low as US\$4.00 to US\$4.50/mcf.

We recently commenced drilling our nine-well pad and expect fracing and completion activities this summer. We are also progressing plans to drill an 18-well pad in the second half of 2011. First shale gas production from the nine-well pad is expected in the fourth quarter of 2011 with production from the 18-well pad expected in late 2012.

Our shale gas capital includes the purchase of almost 175,000 acres of land in the Cordova and Liard basins. This brings our total acreage in northeast BC to over 300,000 acres (100% working interest).

We also recently commenced a process to seek a joint venture partner for various portions of our northeast BC shale gas acreage. This will allow us to monetize a portion of the value that we have created from the success we have had capturing high quality acreage, understanding the reservoir and reducing our costs. We have engaged Bank of America Merrill Lynch as our advisors on this process.

## FINANCIAL RESULTS

### Year-to-Year Change in Net Income

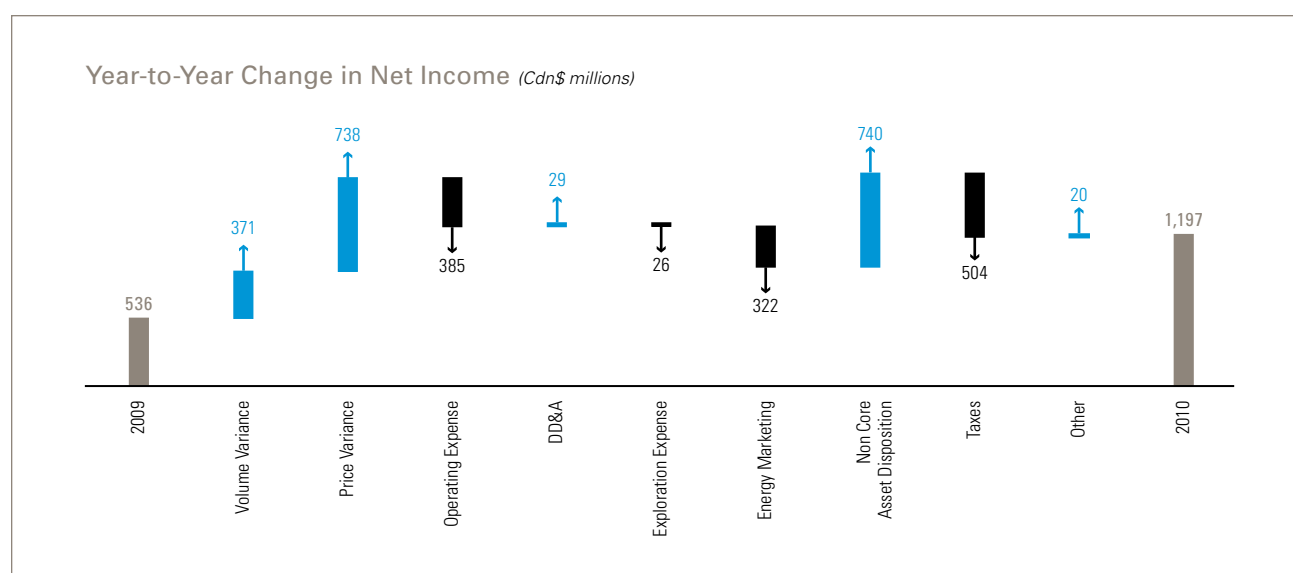
(Cdn\$ millions)

	2010 vs 2009	2009 vs 2008
<b>Net Income for 2009 and 2008<sup>1</sup></b>	<b>536</b>	<b>1,715</b>
Favourable (unfavourable) variances: <sup>2</sup>		
Production Volumes, After Royalties		
Crude Oil	244	(137)
Natural Gas	57	36
Change in Crude Oil Inventory	70	(80)
Total Volume Variance	371	(181)
Realized Commodity Prices		
Crude Oil	711	(1,871)
Natural Gas	27	(313)
Total Price Variance	738	(2,184)
Oil & Gas Operating Expense	(385)	9
Oil & Gas Depreciation, Depletion, Amortization and Impairment	29	241
Exploration Expense	(26)	100
Non-core Asset Disposition Gains	740	-
Energy Marketing Revenue, Net	(322)	605
Chemicals Contribution	(48)	73
General and Administrative Expense	15	(240)
Interest Expense	(12)	(218)
Current Income Taxes	(356)	83
Future Income Taxes	(148)	1,114
Change in Fair Value of Crude Oil Put Options	210	(454)
Other	(145)	(127)
<b>Net Income for 2010 and 2009<sup>1</sup></b>	<b>1,197</b>	<b>536</b>

<sup>1</sup> Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).

<sup>2</sup> All amounts are presented before provision for income taxes.

Significant variances in net income are explained in the sections that follow.



## OIL & GAS

### Production

	2010		2009		2008	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
<b>Oil and Liquids</b> (mbbls/d)						
United Kingdom	104.9	104.8	98.0	98.0	99.7	99.7
Canada <sup>2</sup>	7.5	5.8	14.6	11.4	16.2	12.3
Long Lake Bitumen <sup>3</sup>	15.9	15.1	7.9	7.9	3.9	3.9
Syncrude	21.2	19.6	20.2	18.6	20.9	18.2
United States	9.9	9.0	10.5	9.5	9.3	8.1
Yemen	41.3	23.1	49.9	29.8	56.6	30.6
Other Countries	2.1	1.9	3.5	3.2	5.8	5.3
	202.8	179.3	204.6	178.4	212.4	178.1
<b>Natural Gas</b> (mmcf/d)						
United Kingdom	35	35	24	24	18	18
Canada <sup>2</sup>	126	116	139	128	131	109
United States	99	94	65	57	78	66
	260	245	228	209	227	193
<b>Total</b> (mboe/d)	<b>246</b>	<b>220</b>	<b>243</b>	<b>213</b>	<b>250</b>	<b>210</b>

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

<sup>2</sup> Includes the following production from discontinued operations. See Notes 18 and 20 to our Consolidated Financial Statements.

<sup>3</sup> We report bitumen as production until we are consistently operating the upgrader and producing PSC™.

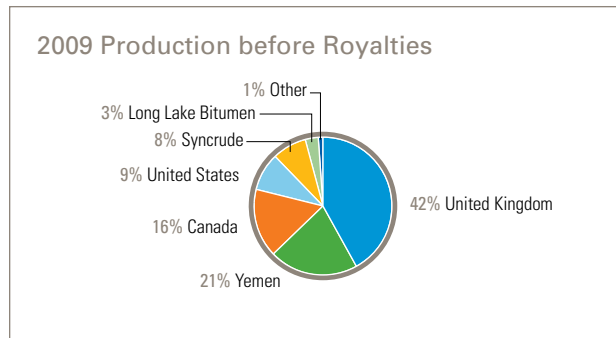
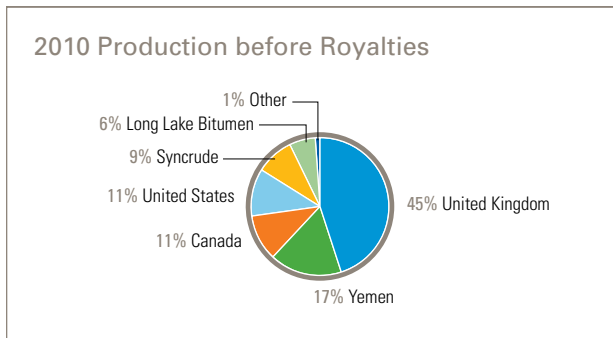
	2010	2009	2008
<b>Before Royalties</b>			
Crude Oil and NGLs (mbbls/d)	7.5	14.6	16.2
Natural Gas (mmcf/d)	6	13	15
<b>After Royalties</b>			
Crude Oil and NGLs (mbbls/d)	5.8	11.4	12.3
Natural Gas (mmcf/d)	5	11	12

### 2010 VS 2009—HIGHER VOLUMES INCREASED INCOME BY \$371 MILLION

Production before royalties averaged 246,000 boe/d, slightly higher than 2009. After adjusting for the impact of heavy oil volumes disposed midway through the year, production increased 5% over last year. A full year of production at Ettrick in the North Sea and at Longhorn in the Gulf of Mexico, and higher bitumen production at Long Lake, offset natural declines in Yemen. Production after royalties increased 3% from the prior year to average 220,000 boe/d, as we produced more from lower royalty jurisdictions.

The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
2009 Production	243	213
Production Related to Disposed Properties	(8)	(7)
	235	206
<b>Production Changes</b>		
United Kingdom	9	9
Long Lake Bitumen	8	7
United States	6	6
Yemen	(9)	(7)
Other	(3)	(1)
<b>2010 Production</b>	<b>246</b>	<b>220</b>



Fourth quarter production before royalties averaged 246,000 boe/d (227,000 after royalties), 7,000 boe/d higher than the prior quarter. The increase was due to improved uptime at Scott/Telford in the UK North Sea and at Syncrude, higher production rates at Long Lake, and new shale gas volumes brought on-line. Compared to the fourth quarter of 2009, production is 19,000 boe/d lower. The decrease reflects the disposition of our Canadian heavy oil assets in the third quarter of 2010, natural declines at Yemen and start-up activities of the fourth platform at Buzzard.

Production volumes discussed in this section represent our working interest before royalties.

#### United Kingdom

UK production for the year increased 9% from last year to average 110,700 boe/d, primarily as a result of a full year of production at Ettrick, which came on stream mid 2009.

Buzzard production was down slightly from 2009 due to planned downtime to complete installation and commissioning of the H<sub>2</sub>S processing facilities on the fourth platform. Commissioning is proceeding well and we are near to having it fully integrated with the existing production systems. With the increased H<sub>2</sub>S handling capability, we expect to be able to continue to maintain our high netback Buzzard production at plateau for many more years. We have identified drilling locations to continue our development program at Buzzard into 2013, which is expected to extend our production plateau.

A full year of production from our Ettrick field contributed 14,500 boe/d to our annual average volumes. This was higher than last year when it averaged 4,300 boe/d, as the facilities came on stream in the third quarter of 2009.

Scott/Telford averaged 13,900 boe/d, 3% higher than 2009. The increased production from the successful step-out development well drilled in the third quarter of 2009 was offset by an eight week shut-in during the third quarter of 2010 due to a valve failure on the third-party owned Forties pipeline system. Production in the fourth quarter was also affected by the repairs on the gas export system, which have since been resolved. Production from our non-operated fields at Duart and Farragon averaged 1,800 boe/d in 2010.

In 2011, we expect production from the North Sea to average between 110,000 and 130,000 boe/d. Increases are expected to come from improved uptime at Buzzard, Scott/Telford and Ettrick.

#### Canada

Production in Canada decreased 25% in 2010 primarily as a result of the disposition of our heavy oil assets. Excluding the impact of the disposition, Canadian production decreased 5% from last year. Coalbed methane (CBM) production decreased 9% from 2009 due to natural declines, while our maturing natural gas fields in the Medicine Hat region and the Balzac field were down 12% as we limited investment in conventional natural gas as a result of low natural gas prices.

We continue to invest in shale gas in the Dilly Creek area of the Horn River Basin in northeast British Columbia. During the year, we successfully completed a 144 frac program on our eight-well pad. We recently started producing these wells and are experiencing initial production rates of 8 to 15 mmcf/d per well. We plan to bring our nine-well pad on stream in 2011 with first production expected in the fourth quarter. We expect our share of production from Canada to average between 18,000 and 26,000 boe/d in 2011.

### Long Lake

Bitumen volumes have more than doubled following the successful facility turnaround in the third quarter of 2009 when we replaced valves in the water treatment system, cleaned out the hot lime softeners and isolated the water treatment trains.

In December, the project produced 29,000 bbls/d (gross), matching our previous monthly high achieved in October. We generated positive operating cash flow for the month, the second time we have achieved this milestone. January production has averaged 27,000 bbls/d, reflecting steam interruptions and downhole pump failures.

During December and January, we injected our highest steam volumes of 172,000 and 156,000 bbls/d, respectively. While fluid returns have risen, the bitumen production has not increased proportional to the steam injection. While some lag between steam increasing and bitumen production increasing is expected, we also believe some of the steam is heating high water saturation zones. Our experience on the pilot wells and Pad 7N has given us the confidence that once these zones are heated, bitumen rates and steam-to-oil ratios (SORs) should improve. Our geologic data analysis indicates higher water saturation zones make up only 3 to 5% of our reservoir by volume.

Our three pilot wells were drilled on an area of the lease with a higher concentration of these zones. The SOR on these wells initially declined to under 4, and then began to rise as the steam encountered these zones. The pilot was temporarily suspended in 2006. With the start-up of the commercial SAGD operation in 2008, we re-heated the pilot wells and after steaming through the zone of higher water saturation, two of those wells are now producing in line with our design expectations of 700 bbls/d per well pair of oil at an SOR of 3.0, while the third well is restricted due to mechanical well bore issues.

We also saw this behavior on Pad 7N, which is located on some of our highest quality reservoirs. Once again, after ramping-up quickly, bitumen volumes stopped growing and SORs rose as we encountered a high water saturation zone. Once we steamed through it, performance improved and now it is, as expected, our best performing pad with five wells averaging 1,200 bbls/d per well pair at an SOR of 2.3.

Our experiences with the pilot wells and Pad 7N have provided us with valuable knowledge in dealing with our reservoir. We have learned that it is important to continue to inject consistent steam when we encounter these high water saturation zones and to lift all produced fluids with appropriate pumping and water-handling capacity. While we heat through them, there are times when we are returning up to 10% more water than we are injecting as opposed to the more usual 5 to 10% water losses. This occurs as the steam displaces formation water in these zones. As we currently have limited water disposal capacity this results in the need to limit production of fluids to achieve overall water balance with a resulting impact on bitumen volumes. We expect to increase our water disposal capacity in the next few months using existing disposal well capacity and low cost de-bottlenecking of facilities.

Various initiatives are underway to move us towards achieving our expectations of 600 to 800 bbls/d per well pair of bitumen at an SOR of 3 to 4. The increased reliability and availability of steam is allowing us to heat through these high water saturation zones faster. The expansion of our gas inlet capacity will allow us to generate more steam, with more consistent fuel availability independent of day-to-day upgrader operations. Pads 12 and 13 are expected to be available for start-up next year, and the addition of two once-through steam generators will increase our steam capacity by late next year. In the meantime, bitumen rates and SORs will be variable as we steam through these zones with higher water saturations.

### Syncrude

Syncrude production increased 5% from last year to average 21,200 boe/d for the year. Production in 2010 was impacted by several factors including a scheduled turnaround of the LC finer and Coker 8-1 as well as unscheduled maintenance on both the sour water treatment and vacuum distillation units. In 2011, we expect our share of production to average between 20,000 and 24,000 boe/d.

### United States

Production in the Gulf of Mexico increased 5,100 boe/d from 2009, primarily as a result of a full year of production from our non-operated Longhorn development, which came on stream in late 2009. This was partially offset by natural field declines at Aspen and Gunnison. Our shelf production decreased 7% from last year as a result of natural declines and limited capital investment in these mature fields.

The drilling moratorium in the Gulf of Mexico had no significant impact on our shelf and deep-water production during the year. We expect our share of production from the Gulf of Mexico to average between 20,000 and 28,000 boe/d in 2011.

### Yemen

Production in Yemen decreased 17% compared to last year, consistent with our expectations as the field matures and development drilling is reduced. During the year, we drilled 13 development wells at Masila and six development wells at Block 51, as we concentrate our drilling program on maximizing reserve recoveries and economic returns during the remaining term of the contract. We expect our share of Yemen production to average between 28,000 and 35,000 boe/d in 2011.

Our discussions with the Yemen government and our partners for a five-year Masila contract extension beyond the current expiration date of December 17, 2011 are ongoing. There is no assurance that this extension will be received.

### Other Countries

Production from Guando in Colombia decreased to average approximately 2,100 boe/d in 2010. This decline reflected natural field declines and the reduced working interest in the field effective in the second quarter of 2009. Under the terms of our licence, our working interest in the Guando field decreased from 20 to 10% in May 2009 after cumulative production from the field reached 60 million barrels. We expect our share of production to average between 2,000 and 3,000 boe/d in 2011.

### 2009 VS 2008—LOWER VOLUMES DECREASED INCOME BY \$181 MILLION

Production before royalties in 2009 was down 3% from 2008. Lower production in Yemen was partially offset by bitumen production at Long Lake. There were also small production declines in the UK North Sea, Canada and US Gulf of Mexico.

UK production for 2009 was 1% lower than 2008 due to planned downtime at Buzzard for pipeline maintenance, the installation of the jacket for the fourth platform and downtime to relocate the Galaxy III drilling rig. This was largely offset by the start up of Ettrick in the third quarter of 2009 and higher production at Scott/Telford as a result of a successful step-out development well at Telford.

Production in Canada (excluding oil sands) remained consistent with 2008. Slightly lower conventional production from our heavy oil assets were offset by higher CBM production rates. Bitumen production in 2009 doubled from 2008 at Long Lake as we continued to ramp up with increased steam and more wells.

Our mature Yemen fields declined as expected. Production from the Masila field declined 14% in 2009 while our East Al Hajr field on Block 51 had slight declines with successful well optimization and pressure maintenance.

Our US production fell 4% in 2009 due to natural declines in our mature shelf production. In the deep-water, production remained consistent with 2008. Longhorn was brought on stream in late 2009. This new production, with higher production volumes at Aspen, was offset by Green Canyon 6, 50 and 137, which remained shut-in following Hurricane Ike in 2008.

## Commodity Prices

	2010	2009	2008
<b>Crude Oil</b>			
West Texas Intermediate (WTI) (US\$/bbl)	79.52	61.80	99.65
Dated Brent (Brent) (US\$/bbl)	79.47	61.51	96.99
Benchmark Differentials <sup>1</sup> (US\$/bbl)			
Heavy Oil	(14.45)	(9.91)	(20.27)
Mars	(1.54)	(1.48)	(6.21)
Masila	0.09	(0.39)	(4.31)
Realized Prices from Producing Assets (Cdn\$/bbl)			
United Kingdom	79.02	67.70	96.23
Canada	61.39	53.04	74.51
Oil Sands—Long Lake	77.07	–	–
Oil Sands—Syncrude	81.23	70.96	105.47
United States	76.73	65.01	104.94
Yemen	81.86	68.49	99.87
Other Countries	76.83	59.05	98.98
Corporate Average (Cdn\$/bbl)	78.94	66.85	96.92
<b>Natural Gas</b>			
New York Mercantile Exchange (US\$/mmbtu)	4.39	4.16	8.90
AECO (Cdn\$/mcf)	3.92	3.92	7.71
Realized Prices from Producing Assets (Cdn\$/mcf)			
United Kingdom	5.28	3.95	6.78
Canada	3.94	3.78	7.73
United States	4.97	4.67	10.07
Corporate Average (Cdn\$/mcf)	4.54	4.06	8.44
<b>Nexen's Average Realized Oil and Gas Price</b> (Cdn\$/boe)	<b>70.11</b>	<b>60.02</b>	<b>89.78</b>
Average Foreign Exchange Rate—Canadian to US Dollar	0.9709	0.8757	0.9381

<sup>1</sup> These differentials are a premium/(discount) to WTI.

### 2010 VS 2009—HIGHER REALIZED PRICES INCREASED NET INCOME BY \$738 MILLION

Crude oil prices continued to strengthen in 2010 with both WTI and Dated Brent increasing 29% compared to last year, averaging about US\$79.50/bbl for the year. The impact of higher crude oil prices was partially reduced by the stronger Canadian dollar, while our realized crude oil price was 18% higher than 2009. NYMEX natural gas prices increased 6% from the prior year, while AECO stayed flat at \$3.92/mcf. Our realized natural gas price increased 12% to average \$4.54/mcf, primarily due to the stronger prices in the UK.

The Canadian dollar continued to strengthen against the US dollar in 2010 and exited the year above parity. This foreign exchange impact reduced our net sales by approximately \$600 million, as our realized crude oil and gas prices were \$8.58/bbl and \$0.49/mcf lower, respectively. However, our US-dollar denominated debt, operating expenses and capital expenditures are lower when translated to Canadian dollars.

### Crude Oil Reference Prices

Crude oil prices were 29% higher than 2009. WTI traded between US\$65/bbl and US\$90/bbl during the year. Prices responded to an imbalanced and volatile global economic recovery. The main drivers supporting crude oil prices were macro-related including a continuing rally in US equity markets, positive investment flows into commodity markets in response to the weakening US dollar and more optimistic outlooks for global economic recovery. Developing countries are experiencing strong economic growth while developed countries are recovering slowly and tentatively from a deep financially-led recession. The US Federal Reserve flagged deflation as a significant concern and signaled that it will, if necessary, engage in quantitative easing (printing money to buy US treasuries to increase market liquidity, lower interest rates and reduce the US dollar exchange rate) to stem this risk. Because oil is a US dollar based global commodity, quantitative easing

would apply upward pressure to crude oil prices, as well as encourage financial investments in oil as investors use oil to hedge their exposure to a declining US dollar.

Near-term supply/demand fundamentals tightened at the end of the year providing support for stronger crude prices. China is tightening its fiscal and monetary policies to keep inflationary pressures in check. Crude prices are vulnerable to weakening demand from China if their tightening policy proves excessive.

Geopolitical events during the year included the Macondo well blowout and Gulf of Mexico drilling ban, the Greek debt crisis, possible UN sanctions against Iran, and tensions between North and South Korea. All of these events were supportive to crude oil prices but did not have a sustained material impact on them. As OPEC's spare capacity and global inventory levels are reduced, crude oil price sensitivity to geopolitical events is likely to increase.

### Crude Oil Differentials

In Canada, heavy crude oil differentials were volatile, averaging \$14.45/bbl (18% of WTI). Enbridge capacity curtailments in the latter part of the year widened heavy oil differentials as heavy crude takeaway capacity was restricted. The latter half of the year saw a series of *force majeure* and pipeline capacity apportionments for Western Canadian producers. Our production was not affected by these curtailments.

The Brent/WTI differential fluctuated during the year but traded at an average discount for the year of \$0.05/bbl. Approximately 60% of global crude oil production is priced off of Dated Brent prices. Historically, Brent traded at a discount to WTI because surplus North Sea crude oil has been exported to the US market. With declining North Sea crude production and exports, this differential can shift to

positive or negative depending on short-term supply and demand factors. Overall, the differential favored Brent with higher premiums in the latter half of 2010 because high crude inventory levels at Cushing depressed the price of WTI and North Sea maintenance reduced supply available for export.

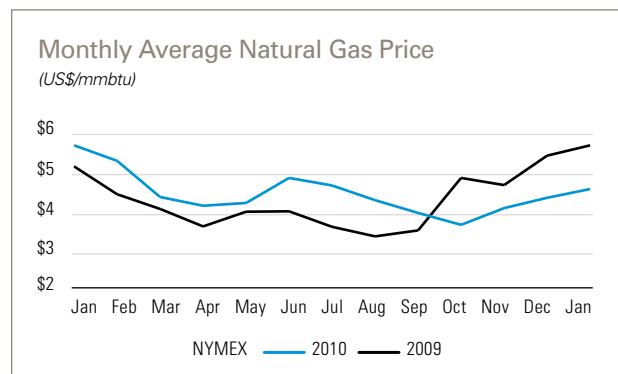
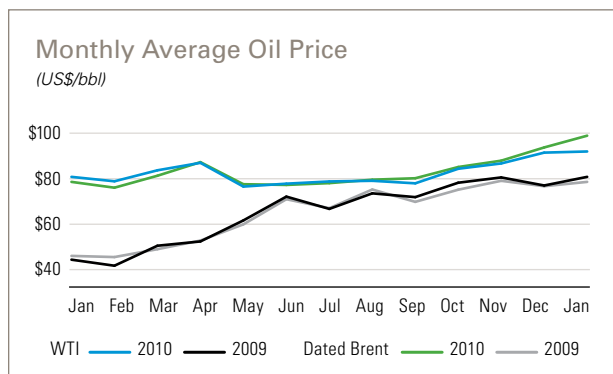
Since late December, international oil prices have risen faster than WTI with Brent trading at a premium of \$10/bbl, as WTI is being held back by high regional inventories. With 80% of our oil production receiving international prices, we will see the benefits of this in 2011.

The Masila price strengthened relative to WTI following the upward movement in the Brent price and the relative strength of Asian demand. The Masila differential averaged at a premium for the year of \$0.09/bbl compared to a discount of \$0.39/bbl in 2009.

Mars is a medium sour crude that is priced to compete with comparable international import alternatives. It does not compete directly with WTI as there is limited pipeline capacity to move crude based from Cushing to the Gulf of Mexico refineries. As a result, the Mars differential narrowed relative to WTI mainly due to WTI's weakness, high crude oil inventories, excess global refining capacity and OPEC cuts in medium crude.

### Natural Gas Reference Prices

Low NYMEX natural gas prices were driven by warm weather and high inventory levels throughout the year. Natural gas producers continue to drill shale plays to retain lands despite low prices. There was a limited spike in gas prices as a result of the winter cold weather but downward pressure on natural gas prices is likely to remain until inventory levels decrease.



## 2009 VS 2008—LOWER REALIZED PRICES DECREASED NET INCOME \$2,184 MILLION

Crude oil prices steadily increased during 2009, after falling dramatically in the fourth quarter of 2008 due to the economic crisis. WTI averaged US\$61.80/bbl for the year, down 38% from 2008, while Dated Brent decreased 37% to average US\$61.51/bbl over the same period. Gas prices fluctuated during the year, with NYMEX averaging US\$4.16/mmbtu and AECO averaging \$3.92/mcf, decreases of 53% and 49% from 2008, respectively. The impact of lower average commodity prices was partially offset by foreign exchange savings. Our corporate average crude oil price fell 31% to \$66.85/bbl, while our corporate average natural gas price was 52% lower, averaging \$4.06/mcf.

In 2009, the average annual US dollar was stronger than the Canadian dollar as compared to 2008. This reduced the impact of lower benchmark commodity prices, increasing net sales by approximately \$295 million. This impact on sales increased our realized crude oil and natural gas prices by approximately \$4.45/bbl and \$0.27/mcf, respectively.

## Operating Expenses<sup>1</sup>

(Cdn\$/boe)	2010		2009		2008	
	Before Royalties <sup>2</sup>	After Royalties	Before Royalties <sup>2</sup>	After Royalties	Before Royalties <sup>2</sup>	After Royalties
<b>Conventional Oil and Gas</b>						
United Kingdom	8.24	8.24	6.87	6.87	6.75	6.75
Canada	12.31	14.10	12.76	14.80	13.12	16.38
United States	10.02	10.76	12.58	14.10	11.57	13.48
Yemen	10.25	18.69	10.69	18.34	8.51	15.88
Other Countries	6.99	7.52	6.03	6.53	4.52	4.91
Average Conventional	9.37	10.62	9.34	10.76	8.68	10.40
<b>Synthetic Crude Oil</b>						
Long Lake <sup>3</sup>	100.09	105.17	–	–	–	–
Syncrude	36.74	39.78	35.92	39.09	36.53	42.04
<b>Average Oil and Gas</b>	<b>15.67</b>	<b>17.62</b>	<b>11.66</b>	<b>13.33</b>	<b>11.04</b>	<b>13.18</b>

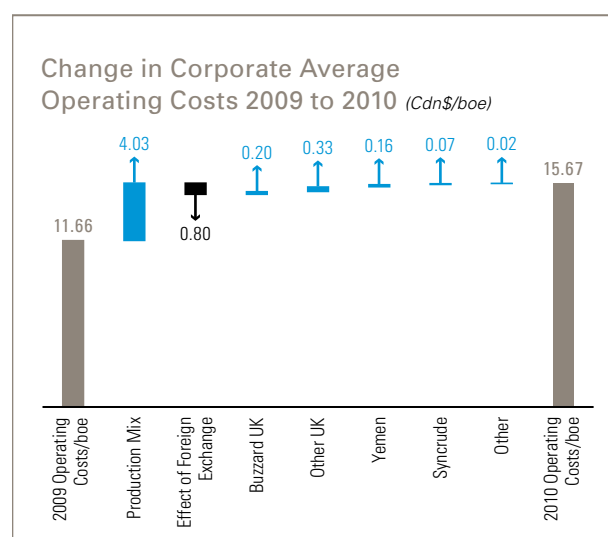
<sup>1</sup> Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).

<sup>2</sup> 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.

<sup>3</sup> Excludes activities related to third-party bitumen purchased, processed and sold.

## 2010 VS 2009—HIGHER OPERATING EXPENSES DECREASED NET INCOME BY \$385 MILLION

Operating costs increased \$385 million from 2009 primarily due to costs associated with our Long Lake project. Long Lake operating costs of \$373 million were expensed during the year. At January 1, 2010, we ceased capitalizing our Long Lake start-up costs. As Long Lake operating costs are mainly fixed, increasing volumes improved our per unit operating cost by about 10% from earlier in the year. When fully ramped up, we expect Long Lake operating costs to be \$25 to \$30/bbl. Elsewhere, a full year of operating costs at Ettrick were offset by reduced maintenance and workover costs in Yemen and the sale of our Canadian heavy oil properties in the third quarter. These production changes increased our corporate average by \$4.03/boe.



In the UK North Sea, Buzzard increased our corporate average by \$0.20/boe due to a combination of higher maintenance activity and slightly lower production. Elsewhere in the UK, higher North Sea costs increased our corporate average by \$0.33/boe. At Scott, the per unit cost increased due to maintenance downtime and third-party outages in the second half of the year.

In Yemen, lower maintenance and workover costs only partially offset the impact of production declines, which increased our corporate average cost by \$0.16/boe. At Syncrude, the impact of additional operating costs was partially offset by higher production volumes. These changes increased our corporate average by \$0.07/boe.

In Canada, the sale of our heavy oil properties in July reduced operating costs by \$52 million as compared to last year. Our heavy oil properties had higher per unit operating costs than our corporate average.

The stronger Canadian dollar reduced our corporate average by \$0.80/boe as operating costs of our international and US assets are denominated in US dollars.

#### **2009 VS 2008—LOWER OPERATING EXPENSES INCREASED NET INCOME BY \$9 MILLION**

Our average oil and gas operating cost increased \$0.62/boe from 2008, as lower costs in Canada and Syncrude were only partially offset by the impact of a stronger US dollar in other areas. US-dollar denominated operating costs were higher when translated to Canadian dollars, increasing our corporate average by \$0.63/boe for 2009.

Changes in our production profile during 2009 increased our corporate average by \$0.47/boe. Buzzard, a lower cost area, contributed a smaller percentage of our total production, year over year, compared to higher cost areas such as Scott/Telford and Ettrick.

In the UK North Sea, lower production rates at Buzzard were more than offset by reduced operating costs due to higher planned downtime and lower production tariffs and logistics costs. This reduced our corporate average by \$0.21/boe. The impact of other areas in the UK North Sea reduced our corporate average by \$0.38/boe. At Scott/Telford, total costs decreased while production was higher due to additional Telford production. This was somewhat offset by the start-up of the Ettrick field and FPSO vessel, where operating costs per barrel are higher than our corporate average.

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 \$0.20/boe. In the US Gulf of Mexico, slightly higher operating costs combined with lower shelf production, increased our corporate average by \$0.02/boe.

Canada reduced our corporate average by \$0.06/boe as lower heavy oil and CBM costs were substantially offset by increased operating costs at Balzac. Our heavy oil properties experienced improved run times and less downtime, which reduced downhole workover costs. This, combined with lower utility costs, reduced operating costs by 14%. CBM costs increased as we brought more wells on stream; however, the incremental production volumes reduced our average cost per barrel. This was partially offset by increased per-unit costs at Balzac, where the impact of declining production has only partially been offset by lower operating costs.

At Syncrude, operating costs decreased as lower natural gas costs were partially offset by higher maintenance costs. The lower operating costs reduced our corporate average by \$0.05/boe.

## Depreciation, Depletion, Amortization and Impairment (DD&A) <sup>1</sup>

(Cdn\$/boe)	2010		2009		2008	
	Before Royalties <sup>2</sup>	After Royalties	Before Royalties <sup>2</sup>	After Royalties	Before Royalties <sup>2</sup>	After Royalties
<b>Conventional Oil and Gas<sup>3</sup></b>						
United Kingdom	20.30	20.32	22.42	22.42	17.72	17.72
Canada	20.13	23.05	18.12	21.03	14.99	18.71
United States	25.87	27.80	37.64	42.18	27.46	31.97
Yemen	7.28	13.28	5.75	9.87	7.75	14.45
Other Countries	11.43	12.29	11.16	12.08	7.90	8.58
Average Conventional	18.27	20.69	19.16	22.09	15.48	18.54
<b>Synthetic Crude Oil</b>						
Long Lake	17.99	18.73	–	–	–	–
Syncrude	6.89	7.46	8.46	9.20	6.39	7.35
<b>Average Oil and Gas</b>	<b>17.26</b>	<b>19.38</b>	<b>18.23</b>	<b>20.90</b>	<b>14.71</b>	<b>17.56</b>

<sup>1</sup> Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).

<sup>2</sup> 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.

<sup>3</sup> DD&A per boe excludes the impairment charges described in Note 4 of our Consolidated Financial Statements.

### 2010 VS 2009— LOWER OIL AND GAS DD&A INCREASED NET INCOME BY \$29 MILLION

Our average DD&A expense decreased \$0.97/boe from last year. The stronger Canadian dollar reduced our corporate average by \$1.61/boe as depletion of our international and US assets is denominated in US dollars. This was more than offset by changes in our production mix which increased our corporate average rate by \$2.05/boe. The change in mix was mainly driven by higher sales volumes at Ettrick, Longhorn and Long Lake, all of which have depletion rates higher than our corporate average.

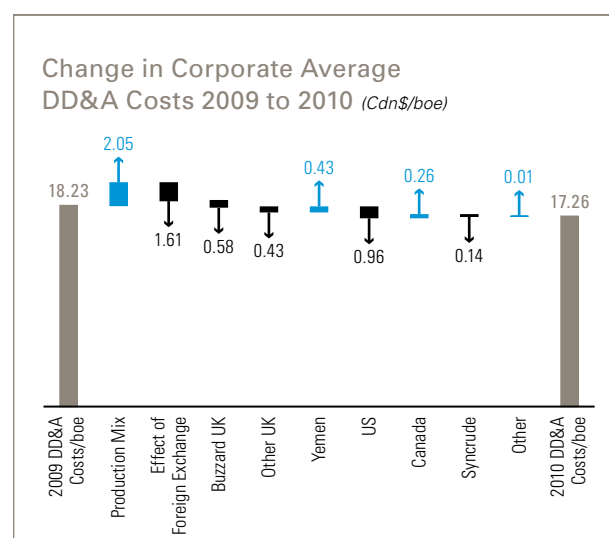
At Buzzard, successful drilling last year enabled us to recognize additional proved reserves at the end of 2009. This lowered the field depletion rate for 2010 and reduced our corporate average by \$0.58/boe. The remainder of our UK fields reduced our corporate average by \$0.43/boe, primarily driven by higher proved reserves at Telford as a result of successful extension drilling of the field.

Higher depletion rates in Yemen increased our corporate average by \$0.43/boe. As the fields mature and production declines, our capital is focused on economically recovering the remaining reserves. Our DD&A rates at Syncrude remain low, reducing our corporate average by \$0.14/boe.

Our Canadian assets increased our corporate average DD&A rate by \$0.26/boe, despite lower DD&A expense with the disposition of heavy oil properties. This increase was driven by higher depletion rates at our CBM and natural gas properties, where low natural gas prices at

the end of 2009 reduced reserves. In the US Gulf of Mexico, positive proved reserve revisions at the end of 2009 reduced our corporate average depletion rate by \$0.96/boe.

Our DD&A expense in 2010 includes non-cash impairment charges of \$93 million on Gulf of Mexico shelf properties. In the third quarter, low natural gas prices triggered an impairment on three small shelf properties. We impaired two additional properties during the fourth quarter where declining production performance and higher estimated future abandonment costs reduced the properties' estimated future cash flows. In each case, the carrying values of the properties were reduced to estimated fair value.



## 2009 VS 2008—LOWER OIL AND GAS DD&A INCREASED NET INCOME BY \$241 MILLION

Our corporate average DD&A cost per barrel in 2009 increased \$3.52/boe from 2008. The stronger US dollar increased our corporate average by \$1.41/boe as depletion of our international and US assets is denominated in US dollars, while changes in our production profile also increased our corporate average by \$0.63/boe. The change in our production mix was primarily a result of: i) slightly lower Buzzard production, where our DD&A rate is low and ii) higher production volumes at Scott/Telford and Ettrick, where we have higher than average DD&A rates. We incurred non-cash impairment charges of \$78 million in the fourth quarter of 2009 at three natural gas properties in Canada and the US. Our year-end natural gas proved reserves at these properties were lower as a result of weak natural gas prices.

In the UK North Sea, our Buzzard depletion rate in 2009 decreased from 2008 as successful development drilling increased our proved reserve estimates at the end of 2008. This lower depletion rate reduced our total corporate average by \$0.16/boe. Elsewhere in the UK, higher depletion rates at Ettrick and Scott/Telford increased our corporate average by \$0.97/boe. The Ettrick depletion rate is higher than our average as a result of higher development costs. The Scott/Telford fields' depletion rate increased compared to 2008 as a result of downward price-related reserve revisions at the end of 2008. Our DD&A expense also includes \$49 million for our Perth discovery in the North Sea, where we expensed allocated acquisition costs as we were unlikely to proceed with development of this prospect.

Lower depletion rates in Yemen, due to lower capital expenditures from drilling fewer development wells and higher reserve estimates, reduced our corporate average by \$0.61/boe. In the Gulf of Mexico, higher estimates for future abandonment costs and downward price-related reserve revisions at the end of 2008 resulted in higher depletion rates, increasing our corporate average rate by \$0.61/boe.

Canadian depletion increased our corporate average by \$0.49/boe. Depletion rates at our heavy oil properties increased in 2009 due to downward price-related revisions to our proved reserves at the end of 2008. This was partially offset by lower depletion rates at our CBM properties, where additional proved reserves were recognized through improved recovery rates.

Syncrude incurred an additional depletion expense of \$14 million in the fourth quarter of 2009 related to the replacement of an asset that was previously damaged at the upgrading facilities. This increased Syncrude's DD&A rate by \$1.95/boe for 2009 and increased our corporate average by \$0.18/boe. Excluding the impact of the additional depletion expense, Syncrude's DD&A rate for 2009 was consistent with 2008.

## Exploration Expense

<i>(Cdn\$ millions)</i>	2010	2009	2008
Seismic	100	81	137
Unsuccessful Drilling	64	115	203
Other	164	106	62
<b>Total Exploration Expense</b>	<b>328</b>	<b>302</b>	<b>402</b>

## 2010 VS 2009—HIGHER EXPLORATION EXPENSE DECREASED NET INCOME BY \$26 MILLION

Our exploration expense increased 9% from 2009. Our exploration program focuses on opportunities in the US Gulf of Mexico, the North Sea and offshore West Africa.

Unsuccessful drilling costs were 44% lower than last year and represented 15% of our exploration drilling capital. In 2009, we expensed 26% of our exploration drilling capital. We expensed costs related to three unsuccessful wells in the North Sea and costs related to CBM properties in Canada in 2010. The Brand well and the Deacon well

in the North Sea failed to encounter hydrocarbons and we expensed drilling costs of \$25 million and \$14 million, respectively. In Canada, we expensed \$17 million of drilling costs related to our CBM exploration activities in central Alberta, where we have no future development plans.

Seismic expenditures increased 23% compared to 2009. Additional purchases in the Gulf of Mexico and the United Kingdom were partially offset by lower spending in Norway and Canada. Seismic data costs will fluctuate depending on

the level of our evaluation stage. Other exploration costs include support costs, lease rental expenses and unutilized drilling rig costs.

Early in the year, we made a significant oil discovery at Appomattox in the Gulf of Mexico. We subsequently completed two appraisal sidetracks. Further appraisal wells were planned, however, additional drilling has been delayed as a result of the drilling moratorium in the Gulf of Mexico. We anticipate resuming appraisal drilling here in 2011. Appomattox is the third discovery in the area following previous successful drilling at Shiloh and Vicksburg. Our drilling plans also include further appraisal drilling at Vicksburg, located six miles east of Appomattox and has the potential to be co-developed. 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 North Sea, we drilled successful wells at Polecat and West Rochelle, and a successful follow up to our Blackbird discovery.

**2009 VS 2008—LOWER EXPLORATION EXPENSE INCREASED NET INCOME BY \$100 MILLION**

Exploration expenditures in 2009 decreased \$56 million from 2008 as we focused our capital on the US Gulf of Mexico, the North Sea and shale gas in Canada. Exploration expense decreased 25% over the same period due to more successful exploration wells in 2009 and lower seismic data acquisition costs.

In the UK, we had significant exploration success in the Golden Eagle area, which includes our operated interest in Golden Eagle, Hobby and Pink. In total, we have drilled three exploration and eleven appraisal wells here.

We drilled a successful exploration well in the southern portion of Oil Prospecting License (OPL) 223, offshore West Africa in 2009. The Owowo South B-1 well was drilled in a water depth of 670 metres and is located 20 kilometres east of the Usan field, currently under development. The well reached a total depth of 2,227 metres and discovered several oil-bearing reservoirs.

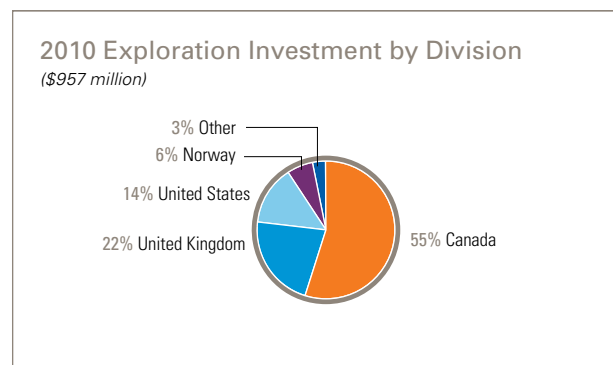
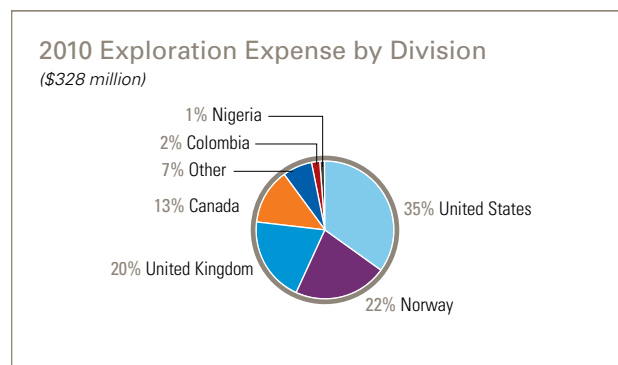
In the Gulf of Mexico, drilling operations at Appomattox were ongoing at December 31, 2009. We also completed a successful appraisal well at Knotty Head in 2009, which was drilled by our first contracted deep-water rig, the Ensco 8501.

We made significant progress on our shale gas project in the Dilly Creek area of the Horn River Basin in northeast British Columbia. In 2009, we completed a drilling and completion program and realized substantial cost savings and productivity improvements. By the end of 2009, we had five shale gas wells on stream.

Unsuccessful drilling expense in 2009 includes expensing CBM drilling costs in Canada and unsuccessful wells in the Eastern Gulf of Mexico and UK North Sea.

In Canada, we expensed costs of \$49 million related to our CBM exploration activities in central Alberta on properties where we had no future development plans. In the Gulf of Mexico, the Antietam well encountered thick, good-quality sand, but was non-commercial and subsequently plugged and abandoned. We expensed costs of \$31 million here in 2009. We also chose not to proceed with the development of a small discovery at Green Canyon 448 and accordingly, expensed \$14 million of costs.

During 2009, seismic data acquisition costs were \$56 million lower than 2008 when we purchased significant seismic data associated with newly acquired blocks in the Norwegian North Sea.



## OIL & GAS NETBACKS

Netbacks are the cash margins we receive for every equivalent barrel sold before general and administrative expenses and cash taxes in the UK. Our netbacks improved 36% since 2006, while WTI and Brent are up 20% and 22%, respectively. Our cash netbacks are 63% of realized sales prices in 2010. This is caused by transitioning our production to lower royalty jurisdictions and stronger commodity prices.

	2010	2009	2008	2007	2006
Oil and Gas Realized Sales Price (Cdn\$/boe)	70.11	60.02	89.78	68.46	62.92
Cash Netback (Cdn\$/boe)	44.38	38.55	60.64	43.22	32.75
Cash Netback as % of Realized Sales Price	63%	64%	68%	63%	52%

The following table includes the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties.

### Before Royalties<sup>1</sup>

		2010							
(Cdn\$/boe)		UK	Canada	Long Lake	Syncrude	US	Yemen	Other	Total
Sales		76.51	34.33	77.07	81.23	47.35	81.86	76.83	70.11
Royalties and Other		–	(5.29)	(3.65)	(6.27)	(3.55)	(36.65)	(5.37)	(8.16)
Operating Expenses		(8.24)	(12.31)	(100.09)	(36.74)	(10.02)	(10.25)	(6.99)	(15.67)
In-country Taxes <sup>2</sup>		–	–	–	–	–	(10.80)	–	(1.90)
<b>Cash Netback</b>		<b>68.27</b>	<b>16.73</b>	<b>(26.67)</b>	<b>38.22</b>	<b>33.78</b>	<b>24.16</b>	<b>64.47</b>	<b>44.38</b>

		2009							
(Cdn\$/boe)		UK	Canada	Long Lake	Syncrude	US	Yemen	Other	Total
Sales		65.93	34.58	–	70.96	46.27	68.49	59.05	60.02
Royalties and Other		–	(5.75)	–	(6.04)	(4.89)	(28.94)	(4.52)	(8.06)
Operating Expenses		(6.87)	(12.76)	–	(35.92)	(12.58)	(10.69)	(6.03)	(11.66)
In-country Taxes <sup>2</sup>		–	–	–	–	–	(8.31)	–	(1.75)
<b>Cash Netback</b>		<b>59.06</b>	<b>16.07</b>	<b>–</b>	<b>29.00</b>	<b>28.80</b>	<b>20.55</b>	<b>48.50</b>	<b>38.55</b>

		2008							
(Cdn\$/boe)		UK	Canada	Long Lake	Syncrude	US	Yemen	Other	Total
Sales		94.45	58.34	–	105.47	79.02	99.87	98.98	89.78
Royalties and Other		–	(12.25)	–	(15.11)	(11.03)	(46.94)	(7.88)	(15.06)
Operating Expenses		(6.75)	(13.12)	–	(36.53)	(11.57)	(8.51)	(4.52)	(11.04)
In-country Taxes <sup>2</sup>		–	–	–	–	–	(13.31)	–	(3.04)
<b>Cash Netback</b>		<b>87.70</b>	<b>32.97</b>	<b>–</b>	<b>53.83</b>	<b>56.42</b>	<b>31.11</b>	<b>86.58</b>	<b>60.64</b>

## After Royalties<sup>1</sup>

2010								
(Cdn\$/boe)	UK	Canada	Long Lake	Syncrude	US	Yemen	Other	Total
Sales	76.51	34.33	77.07	81.23	47.35	81.86	76.83	70.11
Operating Expenses	(8.24)	(14.10)	(105.17)	(39.78)	(10.76)	(18.69)	(7.52)	(17.62)
In-country Taxes <sup>2</sup>	–	–	–	–	–	(19.69)	–	(2.15)
<b>Cash Netback</b>	<b>68.27</b>	<b>20.23</b>	<b>(28.10)</b>	<b>41.45</b>	<b>36.59</b>	<b>43.48</b>	<b>69.31</b>	<b>50.34</b>

2009								
(Cdn\$/boe)	UK	Canada	Long Lake	Syncrude	US	Yemen	Other	Total
Sales	65.93	34.58	–	70.96	46.27	68.49	59.05	60.02
Operating Expenses	(6.87)	(14.80)	–	(39.09)	(14.10)	(18.34)	(6.53)	(13.33)
In-country Taxes <sup>2</sup>	–	–	–	–	–	(14.26)	–	(2.00)
<b>Cash Netback</b>	<b>59.06</b>	<b>19.78</b>	<b>–</b>	<b>31.87</b>	<b>32.17</b>	<b>35.89</b>	<b>52.52</b>	<b>44.69</b>

2008								
(Cdn\$/boe)	UK	Canada	Long Lake	Syncrude	US	Yemen	Other	Total
Sales	94.45	58.34	–	105.47	79.02	99.87	98.98	89.78
Operating Expenses	(6.75)	(16.38)	–	(42.04)	(13.48)	(15.88)	(4.91)	(13.18)
In-country Taxes <sup>2</sup>	–	–	–	–	–	(24.83)	–	(3.63)
<b>Cash Netback</b>	<b>87.70</b>	<b>41.96</b>	<b>–</b>	<b>63.43</b>	<b>65.54</b>	<b>59.16</b>	<b>94.07</b>	<b>72.97</b>

1 Before-royalty cash netbacks are calculated by dividing sales, royalties and other, operating expenses and in-country taxes by production before royalties.

After-royalty cash netbacks are calculated by dividing sales, operating expenses and in-country taxes by production after royalties.

2 Comprises income taxes payable in Yemen that are included in the government's share of profit oil.

## ENERGY MARKETING

(Cdn\$ millions)	2010	2009	2008
<b>Contribution to Net Marketing Revenue by Region</b>			
North America	21	318	(284)
International	5	30	27
<b>Net Marketing Revenue<sup>1</sup></b>	<b>26</b>	<b>348</b>	<b>(257)</b>
Depreciation, Depletion, Amortization and Impairment	(18)	(27)	(19)
General and Administrative	(69)	(91)	(79)
Net Loss on Dispositions	(103)	–	–
Allowance for Doubtful Receivables	–	5	(54)
<b>Marketing Contribution to Income before Income Taxes</b>	<b>(164)</b>	<b>235</b>	<b>(409)</b>
<b>Physical Sales Volumes<sup>2</sup></b>			
North America Crude Oil (mbbls/d)	747	827	656
International Crude Oil (mbbls/d)	77	94	99
North America Natural Gas (bcf/d)	2.8	3.1	6.7
<b>Value-at-Risk</b>			
Year End	11	11	25
High	15	24	40
Low	4	9	19
Average	10	15	30

1 Net Marketing Revenue includes net sales, marketing and other revenue, operating, transportation and other expenses in the Consolidated Statement of Income.

2 Excludes inter-segment transactions. Physical volumes represent amounts delivered during the year.

### 2010 VS 2009—LOWER CONTRIBUTIONS FROM ENERGY MARKETING REDUCED NET INCOME BY \$322 MILLION

Energy marketing generated \$224 million of proceeds in 2010 from dispositions including the sale of our European gas and power business, our North America natural gas trading operations and our crude oil lease gathering, pipeline and storage assets in North Dakota and Montana, thereby substantially completing the re-alignment of our energy marketing business to focus on marketing proprietary crude oil production from North America, the North Sea and Yemen.

Results from energy marketing for the year are lower compared to last year when our marketing contribution was buoyed by the increased value of our natural gas inventories with rising gas prices in late 2009. Gains generated during the fourth quarter of 2010 from capturing crude oil contango (increasing future prices) were offset by widening heavy oil differentials in 2010.

Our North America crude oil team generated positive results in 2010 from blending activities and capturing contango in the forward price curve, offset somewhat by losses from widening differentials. In 2009, we generated strong results due to steep contango early in the year while 2010 saw modest gains from contango. Losses from widening differentials, particularly late in 2010, are primarily due to reduced capacity on pipelines as a result of apportionment in North America and the consequential challenges to flow product. Due to our strong relationships and access to infrastructure, we did not shut in production from our proprietary crude oil operations during the apportionment in 2010.

Our North America natural gas business recognized gains in late 2009 as a result of unrealized gains on inventory carried at fair value and gains on derivatives used to hedge our transportation capacity. In 2010, losses were generated early in the year from declining spot prices on inventory and narrowing transportation spreads between producing and consuming regions, which impacted our ability to generate profits.

After achieving strong results in 2009, our international crude oil team generated modest gains in 2010 primarily as a result of increased competition from crudes similar to Masila.

### 2009 VS 2008—HIGHER CONTRIBUTIONS FROM ENERGY MARKETING INCREASED NET INCOME BY \$605 MILLION

Energy marketing generated \$348 million in net revenue in 2009, with all businesses contributing positive results.

During the fourth quarter of 2009, energy marketing continued to optimize trading around physical assets, resulting in gains on physical positions and commodity inventory, together with gains from blending in our crude oil business. During the latter part of 2009, gas prices increased as a result of cold weather across North America creating unrealized gains on inventory, which is carried at fair value. We also recognized gains on derivatives used to hedge our transportation capacity.

The largest contribution in 2009 came from our global crude oil business, which generated gains by inventory management and physical business as a result of contango in the forward price curve. These gains were recognized largely in the first quarter of 2009. This contango, combined with narrowing crude oil differentials, enabled us to capture both realized and unrealized gains on our relatively low-risk physical trading strategies.

Similar to 2008, the natural gas business faced a challenging economic environment in 2009. Gas prices remained suppressed while location spreads between markets continued to narrow throughout the year. Early in 2009, the gas business incurred losses as a result of exiting the last of its trading positions from 2008 and from selling natural gas inventory where the offsetting gains on the financial instruments hedging the inventory were recognized in prior periods. Weakness in gas markets reduced the value of holding transportation capacity. Any losses associated with the transportation and storage capacity contracts will be recognized when the contracts are used or sold.

## COMPOSITION OF NET MARKETING REVENUE

<i>(Cdn\$ millions)</i>	2010	2009	2008
Trading Activities (Physical and Financial)	14	339	(287)
Other Activities	12	9	30
<b>Total Net Marketing Revenue</b>	<b>26</b>	<b>348</b>	<b>(257)</b>

### TRADING ACTIVITIES

In our energy marketing group, we enter into contracts to purchase and sell energy commodities (now primarily crude oil). We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. In 2010, we substantially completed the re-alignment of our energy marketing business to focus on marketing proprietary crude oil, which reduced our use of financial and derivative contracts. We account for all derivative contracts using fair value accounting and record the net gain or loss from their revaluation in marketing and other income.

### OTHER ACTIVITIES

We enter into fee-for-service contracts related to transportation and storage 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

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices and, if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives and we use information from markets such as the New York Mercantile Exchange.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those that have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange (formerly Netthruput), independent price publications and over-the-counter broker quotes.
- Level 3—Valuations in this level are those with inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value, which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

At December 31, 2010, the fair value of our derivative contracts used in our energy marketing trading activities totaled \$(18) million. Below is a breakdown of the derivative fair value by valuation method and contract maturity:

(Cdn\$ millions)	Maturity				Total
	< 1 year	1–3 years	4–5 years	> 5 years	
Level 1—Actively Quoted Markets	(17)	–	–	–	(17)
Level 2—Based on Other Observable Pricing Inputs	(11)	(7)	–	–	(18)
Level 3—Based on Unobservable Pricing Inputs	9	8	–	–	17
<b>Fair Value at December 31, 2010</b>	<b>(19)</b>	<b>1</b>	<b>–</b>	<b>–</b>	<b>(18)</b>

### Changes in Fair Value of Derivative Contracts

(Cdn\$ millions)	Total
Fair Value at December 31, 2009	23
Change in Fair Value of Contracts	(2)
Net Losses (Gains) on Contracts Sold	19
Net Losses (Gains) on Contracts Closed	(58)
Changes in Valuation Techniques and Assumptions <sup>1</sup>	–
<b>Fair Value at December 31, 2010</b>	<b>(18)</b>

<sup>1</sup> Our valuation methodology has been applied consistently 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.

## CHEMICALS

(Cdn\$ millions)	2010	2009	2008
Net Sales	456	458	477
Sales Volumes (thousand short tons)			
Sodium Chlorate	476	441	495
Chlor-alkali	492	447	469
Operating Profit <sup>1</sup>	97	143	125
Operating Margin <sup>2</sup>	21%	31%	26%
Chemicals Contribution to Income Before Income Taxes <sup>3</sup>	18	79	(14)
Capacity Utilization	84%	88%	92%

<sup>1</sup> Net sales less operating costs, transportation and other expenses.

<sup>2</sup> Operating profit divided by net sales.

<sup>3</sup> Includes foreign exchange gains and losses on long-term debt.

### 2010 VS 2009—LOWER CHEMICALS CONTRIBUTION DECREASED NET INCOME BY \$48 MILLION

North America chlorate revenue decreased 2% in 2010, as an 11% decrease in prices was partially offset by a 10% increase in sales volumes. North America chlor-alkali revenue remained flat as weaker caustic prices were offset by higher volumes. In Brazil, sales revenues increased by 2% as strong chlorate revenues were partially offset by lower acid revenues. Chlorate revenues increased by 4% as a result of higher prices. This was partially offset by lower acid revenues of 10% as a result of lower prices and sales volumes.

The Canadian dollar continued to strengthen during the year and chemicals contribution includes foreign exchange gains of \$15 million on the Canexus US-dollar denominated debt. The 2009 results included unrealized foreign exchange gains of \$50 million related to Canexus US-dollar denominated debt.

In early 2011, we sold our remaining interest in these chemical operations for \$458 million of cash proceeds and we have no continuing involvement in the business after February 7, 2011. We expect to recognize a gain of approximately \$250 to \$300 million in the first quarter of 2011. Since 2005 when we completed the initial public offering of our chemicals business through Canexus, we have realized proceeds of approximately \$900 million (including cash distributions).

### 2009 VS 2008—HIGHER CHEMICALS CONTRIBUTION INCREASED NET INCOME BY \$73 MILLION

North America chlorate revenue decreased 2% from 2008, as a 13% reduction in sales volumes attributable to the global economic downturn was partially offset by stronger pricing. North America chlor-alkali revenue increased 2% from 2008 as weaker caustic prices somewhat offset higher volumes. In Brazil, lower caustic prices and a decline in sales volumes decreased chlor-alkali revenues 32%. Chlor-alkali sales volumes decreased because we reduced sales of purchased product as this activity generates no gross margin. There was no impact on our returns in Brazil by eliminating this activity. Chlorate sales in Brazil increased 5% from the prior year as a result of higher prices.

The Canadian dollar strengthened in 2009 and chemicals contribution includes unrealized foreign exchange gains of \$50 million on the Canexus US-dollar denominated debt. This compared to our 2008 results, which included unrealized foreign exchange losses of \$54 million.

## CORPORATE EXPENSES

### General and Administrative (G&A)<sup>1</sup>

<i>(Cdn\$ millions)</i>	<b>2010</b>	<b>2009</b>	<b>2008</b>
General and Administrative Expense before Stock-Based Compensation	496	428	417
Stock-Based Compensation <sup>2</sup>	(14)	69	(160)
<b>Total</b>	<b>482</b>	<b>497</b>	<b>257</b>

<sup>1</sup> Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).

<sup>2</sup> Includes cash and non-cash expenses related to our tandem option plan, stock appreciation rights plan and restricted share unit plan.

### 2010 VS 2009—LOWER COSTS INCREASED NET INCOME BY \$15 MILLION

G&A costs decreased 3% from 2009 primarily as the impact of a recovery of stock-based compensation during the year was substantially offset by higher G&A costs. Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation obligations and related expense. During the year, we recovered non-cash stock-based compensation costs of \$41 million as our stock price ended the year at \$22.80/share, compared to the previous year when it closed at \$25.22/share. This recovery was partially offset by cash payments for stock-based compensation programs of \$27 million, 66% lower than last year.

G&A expenses before stock-based compensation increased \$68 million primarily due to non-recurring costs associated with our non-core asset disposition programs.

### 2009 VS 2008—HIGHER COSTS DECREASED NET INCOME BY \$240 MILLION

Higher stock-based compensation expense was the primary reason for the 93% increase in G&A costs in 2009. Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation obligations and related expense. Our stock price fluctuated during the year before closing at \$25.22/share, up 18% from \$21.45/share at the end of 2008. Cash payments made in connection with our stock-based compensation programs in 2009 decreased 29% from 2008 to \$79 million. Cash payments were higher in 2008 as our stock price reached a high of \$43.45/share during the year.

## Interest<sup>1</sup>

<i>(Cdn\$ millions)</i>	<b>2010</b>	<b>2009</b>	<b>2008</b>
Interest	411	389	334
Less: Capitalized	(87)	(77)	(240)
<b>Net Interest Expense</b>	<b>324</b>	<b>312</b>	<b>94</b>
Effective Interest Rate	5.8%	5.0%	5.9%

<sup>1</sup> Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).

### 2010 VS 2009—HIGHER NET INTEREST EXPENSE REDUCED NET INCOME BY \$12 MILLION

Net financing costs increased \$12 million from last year as higher interest costs of \$22 million were partially offset by additional capitalized interest of \$10 million. The higher expense was due to additional borrowing costs of \$52 million on our long-term debt and additional stand-by fees of \$8 million on our term credit facilities. These costs were reduced by the impact of a stronger Canadian dollar, which lowered our US-dollar denominated interest costs by \$41 million.

Capitalized interest was \$10 million higher than last year. Increases in capitalized interest at Usan and on the fourth platform at Buzzard, were partially offset by lower capitalized interest on Ettrick, which was completed in the prior year.

### 2009 VS 2008—HIGHER NET INTEREST EXPENSE REDUCED NET INCOME BY \$218 MILLION

Financing costs increased \$55 million from 2008. This 16% increase was a result of higher levels of debt, partially offset by lower interest rates. Our capital investment program, including the acquisition of an additional 15% interest in Long Lake, exceeded our cash flow, causing us to draw upon of our term credit facility. In addition, we issued US\$1 billion of long-term notes in the third quarter of 2009, increasing interest costs by \$32 million this year. The stronger US dollar increased our US-dollar denominated interest costs for the year by \$32 million.

During 2009, capitalized interest decreased \$163 million from 2008 as a result of completing major development projects. Long Lake capitalized interest in 2009 was \$23 million, down \$183 million from 2008, while Ettrick capitalized interest decreased \$7 million during the year. This was partially offset by an increase in Usan capitalized interest of \$16 million. In addition to our Usan development, we capitalized interest on the construction of the fourth platform at Buzzard and our Chemicals technology conversion project in North Vancouver.

## Income Taxes<sup>1</sup>

<i>(Cdn\$ millions)</i>	<b>2010</b>	<b>2009</b>	<b>2008</b>
Current	1,132	776	859
Future	(368)	(516)	598
<b>Total Provision for Income Taxes</b>	<b>764</b>	<b>260</b>	<b>1,457</b>

<sup>1</sup> Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).

### 2010 VS 2009—HIGHER TAXES DECREASED NET INCOME BY \$504 MILLION

Our total provision for income taxes increased from 2009 as a result of net gains on our non-core asset disposition program and stronger commodity prices, which improved our operating results. Our income tax provision includes current taxes in the United Kingdom, Yemen, Norway, Colombia and the United States.

## 2009 VS 2008—LOWER TAXES INCREASED NET INCOME BY \$1,197 MILLION

Our provision for income taxes decreased by \$1,197 million as compared to the prior year. Lower commodity prices and production, a reduction in Canadian tax rates and a fair value unrealized loss on our crude oil put options contributed to lower tax expense in 2009. During the year, future tax expense was reduced by amortizing the deferred tax credit arising from the internal reorganization and financing of our North Sea assets completed in 2008. Our income tax provision includes current taxes in the United Kingdom, Yemen, Norway, Colombia and the United States.

## Other

<i>(Cdn\$ millions)</i>	<b>2010</b>	<b>2009</b>	<b>2008</b>
Non-core Asset Disposition Net Gains	740	–	–
Increase (Decrease) in Fair Value of Crude Oil Put Options	(41)	(251)	203

In 2010, we realized net gains of \$740 million on the disposition of non-core assets, consisting of the following:

- heavy oil properties in Canada for proceeds of \$939 million, net of closing adjustments, realizing a gain of \$781 million;
- North American natural gas energy marketing operations for proceeds of \$9 million, recognizing a non-cash loss of \$259 million, which were primarily related to the transfer of long-term physical transportation commitments;
- crude oil lease gathering, pipelines and storage assets in North Dakota and Montana for proceeds of \$201 million, realizing a gain of \$121 million;
- lands in the Athabasca region of Northern Alberta for which we had no near-term development plans for proceeds of \$81 million, realizing a gain of \$80 million; and
- undeveloped lease in the UK North Sea for proceeds and gains of \$17 million.

In 2010, we purchased put options on 100,000 bbls/d of our 2011 crude oil production. These options establish a monthly WTI floor price of between US\$50/bbl and US\$63/bbl and provide a base level of price protection without limiting our upside to higher prices. The options settle monthly and are recorded at fair value throughout their term. As a result, changes in forward crude oil prices created gains or losses on these options at each period end. The put options were purchased for \$33 million and are carried at fair value. At December 31, 2010, the fair value of the options was approximately \$9 million and we recorded a fair value loss of \$24 million in the year.

In late 2009, we purchased put options on 90,000 bbls/d of our 2010 crude oil production. These options established a WTI floor price of US\$50/bbl on these volumes. Options on 60,000 bbls/d settled monthly, while the remaining options settled annually. The put options were purchased for \$39 million and were carried at fair value. At December 31, 2009, higher crude oil prices reduced the fair value of the options to \$17 million, and we recorded a fair value loss in 2009 of \$22 million. At December 31, 2010, higher forward crude oil prices reduced the fair value of the options to nil and we expensed the remaining fair value of \$17 million in 2010.

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options were purchased for \$14 million and established an annual Dated Brent floor price of US\$60/bbl on these volumes. At December 31, 2008, the put options had an estimated fair value of \$233 million due to significantly lower crude oil prices. Strengthening crude oil prices in 2009 reduced the fair value of these options to nil and we recorded a fair value loss of \$229 million in 2009.

## SUMMARY OF QUARTERLY RESULTS

	Quarter Ended							
	March 31		June 30		September 30		December 31	
	2010	2009	2010	2009	2010	2009	2010	2009
<i>(Cdn\$ millions)</i>								
Net Sales from Continuing Operations	1,319	880	1,294	1,029	1,298	919	1,500	1,375
Income (Loss) from Continuing Operations before Income Taxes is Comprised of:								
Oil and Gas	487	219	588	286	376	250	476	447
Energy Marketing <sup>1</sup>	(67)	83	(5)	25	(240)	18	113	109
Corporate and Other	(107)	(120)	(149)	(323)	(163)	(66)	(183)	(170)
	<b>313</b>	<b>182</b>	<b>434</b>	<b>(12)</b>	<b>(27)</b>	<b>202</b>	<b>406</b>	<b>386</b>
<b>Net Income (Loss) from Continuing Operations</b>	<b>163</b>	<b>147</b>	<b>250</b>	<b>14</b>	<b>(59)</b>	<b>102</b>	<b>218</b>	<b>249</b>
<b>Net Income</b>	<b>185</b>	<b>135</b>	<b>255</b>	<b>20</b>	<b>537</b>	<b>122</b>	<b>220</b>	<b>259</b>
<b>Earnings (Loss) per Common Share from Continuing Operations (\$/share)</b>								
Canadian GAAP—Basic	0.31	0.28	0.48	0.03	(0.11)	0.20	0.41	0.48
Canadian GAAP—Diluted	0.31	0.26	0.47	0.00	(0.11)	0.17	0.41	0.47
<b>Earnings per Common Share (\$/share)</b>								
Canadian GAAP—Basic	0.35	0.26	0.49	0.04	1.02	0.23	0.42	0.50
Canadian GAAP—Diluted	0.35	0.24	0.48	0.01	1.02	0.21	0.42	0.49
<b>Dividends Declared</b>	<b>0.050</b>	<b>0.050</b>	<b>0.050</b>	<b>0.050</b>	<b>0.050</b>	<b>0.050</b>	<b>0.050</b>	<b>0.050</b>
<b>Common Share Prices (\$/share)</b>								
Toronto Stock Exchange—High	25.91	24.24	26.91	28.54	22.33	25.94	23.00	27.31
Toronto Stock Exchange—Low	22.38	14.86	20.92	20.65	18.33	20.70	20.57	22.26
New York Stock Exchange—High (US\$)	24.98	20.61	26.92	26.25	21.54	24.43	23.01	26.05
New York Stock Exchange—Low (US\$)	21.06	11.89	19.66	16.33	17.20	18.68	20.12	20.66

<sup>1</sup> The third quarter of 2010 includes asset disposition losses of \$259 million and the fourth quarter includes asset disposition gains of \$121 million (see Note 18 of our Consolidated Financial Statements).

In 2010, we substantially completed the realignment of our energy marketing business to focus on marketing proprietary crude oil. As a result, our results in the third quarter includes asset disposition losses of \$259 million and our fourth quarter results includes asset disposition gains of \$121 million (see Note 18 of our Consolidated Financial Statements).

Quarterly variances in net sales and earnings are largely driven by fluctuations in commodity prices and changes

in production volumes due to: the temporary shutdown of facilities for maintenance, natural declines of mature fields and the ramp-up of new producing fields. In addition, disposition net gains of \$740 million were realized in 2010 as a result of our successful non-core asset disposition program, of which \$781 million relating to our Canadian heavy oil disposition is included in discontinued operations (see notes 18 and 20 to our Consolidated Financial Statements).

## OUTLOOK FOR 2011

### Capital Investment

In 2011, we plan to invest between \$2.4 and \$2.7 billion in our oil and gas operations to advance our strategies as follows:

- \$1.5 to \$1.6 billion on the development of Usan, offshore West Africa, development of the Golden Eagle area in the North Sea, a joint development plan to move Knotty Head in the Gulf of Mexico towards sanctioning, and on exploration and appraisal opportunities in the North Sea, Gulf of Mexico, Canada and Colombia;
- \$550 to \$600 million on the oil sands as we focus on Long Lake, advancing our Kinosis project and at Syncrude; and
- \$300 to \$350 million on our drilling and completion programs at our Horn River shale gas play.

Details of our 2011 capital program are included in the Capital Investment section of this MD&A.

### Production

For 2011, we expect our annual production will range between 230,000 and 270,000 boe/d (210,000 to 240,000 boe/d after royalties). The range is driven by the pace of ramp-up at Long Lake, run-times at Buzzard and Scott/Telford in the North Sea and our Horn River shale gas program. We expect to grow production after royalties by approximately 4% assuming the midpoint of our guidance range and 7% after adjusting for the sale of our heavy oil properties in 2010.

(mboe/d)	2011 Estimated Production		2010 Production	
	Before Royalties	After Royalties	Before Royalties	After Royalties
United Kingdom	110-130	110-130	111	111
Canada	18-26	16-23	28	25
Long Lake Bitumen	25-29	22-26	16	15
Syncrude	20-24	18-22	21	19
United States	20-28	17-24	27	25
Yemen	28-35	16-20	41	23
Other Countries	2-3	2-3	2	2
<b>Total</b>	<b>230-270</b>	<b>210-240</b>	<b>246</b>	<b>220</b>

### Cash Flow and Sensitivities

We expect cash flow from operations will range from \$2.1 to \$2.8 billion in 2011, assuming the following:

	Low	High
WTI (US\$/bbl)	\$75	\$90
NYMEX Natural Gas (US\$/mmbtu)	\$4.00	\$5.50
US to Canadian Dollar Exchange Rate	\$1.00	\$1.00

Changes in commodity prices and exchange rates impact our annual cash flow from operating activities, after cash taxes, as follows:

(Cdn\$ millions)	
WTI—US\$1/bbl change above US\$56	42
WTI—US\$1/bbl change below US\$56 <sup>1</sup>	21
NYMEX Natural Gas—US\$0.50/mcf change	18
Exchange Rate—\$0.01 US/Cdn change	26

<sup>1</sup> Our put option program for 2011 mitigates the impact of a price decline below approximately US\$56 WTI.

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Structure

<i>(Cdn\$ millions)</i>	December 31, 2010	December 31, 2009
<b>Net Debt<sup>1</sup></b>		
Bank Debt	–	1,803
Public Senior Notes	4,636	4,982
<b>Total Senior Debt</b>	<b>4,636</b>	<b>6,785</b>
Subordinated Debt	443	466
<b>Total Debt</b>	<b>5,079</b>	<b>7,251</b>
Less: Cash and Cash Equivalents	(1,005)	(1,700)
<b>Total Net Debt<sup>2</sup></b>	<b>4,074</b>	<b>5,551</b>
<b>Nexen Inc. Shareholders' Equity<sup>3</sup></b>	<b>8,707</b>	<b>7,582</b>

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

2 December 31, 2010 excludes Net Debt related to our chemical operations that is included in assets and liabilities held for sale (see Note 20 of our Consolidated Financial Statements). Our remaining interest was sold in February 2011 for \$458 million.

3 Equity is the historical issue price of equity and accumulated retained earnings.

### Net Debt

We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly related to our operating cash flows and capital investment. We ended the year with net debt of approximately \$4,074 million, \$1,477 million lower than 2009. The year-over-year change in our net debt results from:

<i>(Cdn\$ millions)</i>	2010	2009
Capital Investment	2,523	2,742
Proved Property Acquisitions	79	755
Net Proceeds from Non-core Asset Dispositions	(1,262)	(17)
Cash Flow from Operating Activities	(2,349)	(1,886)
Deficiency (Surplus)	(1,009)	1,594
Dividends on Common Shares	104	104
Issue of Common Shares	(55)	(57)
Reclassification of Canexus Net Debt Related to Sale	(391)	–
Other	77	232
Foreign Exchange Translation of US-dollar Debt and Cash	(203)	(897)
<b>Increase (Decrease) in Net Debt</b>	<b>(1,477)</b>	<b>976</b>

Our net debt decreased 27% from last year primarily as a result of our non-core asset disposition program. Our 2010 disposition program included the sale of our heavy oil assets in Canada and the sale of various non-core energy marketing operations. Total proceeds from our disposition program in 2010 was approximately \$1.3 billion. In early 2011, we generated additional proceeds of \$458 million from the sale of our interest in Canexus. Net debt related to Canexus of \$391 million has been included in liabilities held for sale at December 31, 2010.

Our capital investment continues to focus on our three key growth areas of conventional exploration and development, oil sands and unconventional gas. In 2010, our capital

investment and property acquisition costs were approximately \$900 million lower than the previous year, when we acquired our additional 15% interest in Long Lake. Cash flow from operating activities increased from 2009 as a result of higher production and stronger commodity prices. Our oil and gas investment exceeded our operating cash flows by about \$250 million in 2010, largely due to the acquisition of acreage in the Horn River shale gas play. The stronger Canadian dollar relative to the US dollar reduced our US-dollar-denominated debt. We currently have liquidity of approximately \$4 billion, which is comprised of cash and undrawn committed credit facilities, most of which are available until July 2014.

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 manage our investments through the lows of the commodity cycle to create future growth and value for our shareholders over the long term without putting our balance sheet under undue financial risk.

The change in our net debt, combined with higher cash flow and earnings, reduced our leverage in 2010 as reflected in the following ratios:

<i>(times)</i>	<b>2010</b>	<b>2009</b>	<b>2008</b>
Net Debt to Cash Flow from Operating Activities <sup>1</sup>	1.9	2.5	1.1
Interest Coverage <sup>2</sup>	9.3	8.5	15.6

<sup>1</sup> For purposes of this calculation, cash flow from operating activities is before changes in non-cash working capital and other.

<sup>2</sup> Earnings before interest, taxes, DD&A, exploration and other non-cash expenses, divided by interest expense (before capitalized interest).

For the 12 months ended December 31, 2010, our net debt to cash flow from operating activities (before changes in non-cash working capital and other) ratio was 1.9 times (WTI average of US\$79.52) compared to 2.5 times at December 31, 2009 (WTI average of US\$61.80). On a pro forma basis adjusted for the sale of Canexus it would be 1.7 times, whereas using WTI US\$96 experienced in 2008, our ratio would be 1.1 times. 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, where we are in our 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.

## Change in Working Capital

<i>(Cdn\$ millions)</i>	<b>December 31 2010</b>	<b>December 31 2009</b>	<b>Increase (Decrease)</b>
Cash and Cash Equivalents	1,005	1,700	(695)
Restricted Cash	40	198	(158)
Accounts Receivable	1,938	2,788	(850)
Inventories and Supplies	549	680	(131)
Accounts Payable and Accrued Liabilities	(2,545)	(3,038)	493
Other	33	70	(37)
<b>Total</b>	<b>1,020</b>	<b>2,398</b>	<b>(1,378)</b>

Our working capital balances decreased significantly from last year. Cash and cash equivalents decreased \$695 million as we used proceeds from the disposition program and cash on hand to fund our capital investment shortfall and repay our term credit facilities during the year. Accounts receivable, inventory and accounts payable reduced as a result of changes in our energy marketing group and the disposition of our heavy oil properties in Canada. The sale of our North American natural gas operations included the transfer of inventory, accounts receivable and payable balances to the purchaser. This, combined with reduced trading activity as we focus on supporting our core physical business as a producer/marketer, reduced our energy marketing working capital requirements from 2009.

Our working capital balances at December 31, 2010 exclude accounts receivable, inventories and accounts payable related to our chemicals operations as these balances are included in assets and liabilities held for sale.

At December 31, 2010, our restricted cash consists of margin deposits of \$40 million (2009—\$198 million) related to exchange-traded derivative financial contracts used by our energy marketing group to economically hedge physical commodities, storage, transportation and customer sales contracts. We are required to maintain margin for net out-of-the-money derivative financial contracts.

The weaker US dollar at the end of the year impacted our US-dollar denominated working capital by decreasing accounts receivable, inventories and accounts payable by approximately \$123 million, \$19 million and \$123 million, respectively.

## Liquidity

We generally rely on operating cash flows to fund capital requirements over time and provide liquidity. Given the long cycle-time of some of our development projects and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow in any given year. We also require liquidity for our energy marketing business. We believe that maintaining strong liquidity is critical during periods of uncertain economic markets. We currently have liquidity of approximately \$4 billion, comprised of cash and undrawn committed credit facilities.

We maintain significant committed and unsecured credit facilities. At December 31, 2010, we had term credit facilities of \$3 billion that are available until July 2014, of which \$322 million was utilized to support letters of credit. We also had \$464 million of uncommitted, unsecured credit facilities, of which \$112 million was supporting letters of credit outstanding at December 31, 2010.

From time to time, we access capital markets to meet our financing needs. We also use financial instruments to minimize exposure to fluctuating commodity prices and foreign exchange. For example, we routinely purchase WTI and Dated Brent put options to establish a minimum value for our production. We manage our capital structure to maintain flexibility so we can fund our capital programs given the cyclical nature of the oil and gas business.

The following table shows how we financed our business activities over the last five years. When our operating cash flows exceed our investment requirements, we generally pay down debt or return cash to shareholders. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

<i>(Cdn\$ millions)</i>	<b>2010</b>	<b>2009</b>	<b>2008</b>	<b>2007</b>	<b>2006</b>
Cash Flow from Operating Activities	2,349	1,886	4,354	2,830	2,374
Cash Flow from Investing Activities	(1,422)	(3,743)	(3,189)	(3,281)	(3,388)
Surplus (Deficiency)	927	(1,857)	1,165	(451)	(1,014)
Cash Flow from Financing Activities	(1,506)	1,821	322	677	1,081
<b>Net Cash Generated (Used)</b>	<b>(579)</b>	<b>(36)</b>	<b>1,487</b>	<b>226</b>	<b>67</b>

In 2006, we borrowed approximately \$1 billion under our committed term credit facilities and used cash flow from operating activities to fund our capital program. In 2007, we issued US\$1.5 billion in senior debt to repay outstanding term credit facilities and \$150 million in medium-term notes, as well as to fund our 2007 capital program.

In 2008, our cash flow from operating activities exceeded capital expenditures by approximately \$1.3 billion and we used this excess to: i) build our cash balances; ii) repay debt including maturing medium term notes of \$125 million; and iii) repurchase approximately 12 million common shares at a cost of \$338 million.

In 2009, our capital investment, including the acquisition of an additional working interest in Long Lake, exceeded our cash flow from operating activities. The purchase of Long Lake was funded primarily from accumulating excess cash in 2008. In response to improving credit markets, we also issued US\$1 billion of senior notes during the year, with US\$300 million maturing in 2019 and US\$700 million maturing in 2039. Proceeds from the debt issue were used to repay a portion of our outstanding term credit facilities as well as for general corporate purposes.

In 2010, we repaid \$1.5 billion of term credit facilities using proceeds from our non-core asset disposition program. Repaying our outstanding term credit facilities increased the average term-to-maturity of our debt to 21 years.

Our marketing business also requires liquidity to support its activities. We require liquidity for working capital and cash or credit lines to fund collateral requirements and to absorb unexpected market or credit losses. The commercial agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to

effectively manage credit risk. These agreements can require collateral to be posted if adverse credit-related events, such as reduced credit rating to non-investment grade, occur. We have developed mitigation strategies to significantly reduce our overall exposure if such a downgrade were to occur. We believe our current liquidity is sufficient to fund this exposure, if necessary. Additionally, our exchange-traded contracts require that we provide margin based on daily fluctuations in the value of our contracts. The largest single-day margin call we received during 2010 was \$13 million. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required if our credit ratings were reduced.

## Future Liquidity

Our future liquidity depends upon cash flow generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Our 2011 capital investment budget is approximately \$2.4 to \$2.7 billion, and our cash flow from operations is expected to be \$2.1 to \$2.8 billion at WTI of US\$75 to US\$90. We continue to monitor economic conditions and commodity prices and will adjust our capital investment program accordingly.

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. Refer to the Outlook for 2011 section on page 97 to see how changes in the above assumptions can impact our cash flow.

At December 31, 2010, we had \$1 billion in cash, US\$3 billion of undrawn committed credit facilities and \$464 million of undrawn uncommitted credit facilities. The only debt maturity of significance in the next few years is our US\$500 million notes, which mature in November 2013. Given the long term-to-maturity of a significant portion of our debt, we believe we are well positioned to bring our development projects to production and pursue our next generation of growth while preserving our liquidity.

Our debt maturities over the next five years are:

<i>(Cdn\$ millions)</i>	2011	2012	2013	2014	2015
Term Credit Facilities <sup>1</sup>	-	-	-	-	-
Long-Term Notes	-	-	497	-	249
<b>Total<sup>2</sup></b>	-	-	<b>497</b>	-	<b>249</b>

<sup>1</sup> US\$3 billion available until July 2014.

<sup>2</sup> Excludes debt related to our chemical operations that are included in liabilities held for sale (see Note 20 of our Consolidated Financial Statements).

For the past several years, we invested significant capital in a number of major development projects, including Buzzard, Long Lake, Ettrick and Usan. The large capital investment required in these projects is substantially behind us and we expect these assets will make significant contributions to our future cash flows. Cash flows generated from these projects allow us to repay debt and invest in our next generation of new growth projects, such as: i) Usan, offshore West Africa; ii) shale gas in the Horn River Basin; and iii) the Golden Eagle area in the UK North Sea. In 2011, we expect to invest \$500 million to progress our Usan development, \$350 million at Horn River and \$150 million at Golden Eagle. We maintain significant undrawn committed credit facilities to manage these risks. We also have a US\$3.5 billion shelf prospectus filed in the US and Canada for sales of debt securities and common shares, under which we issued US\$1 billion of debt securities in July 2009. This shelf prospectus is due to expire in July 2011.

We are well positioned with our current debt structure.

Our only debt covenant requires us to maintain a debt to EBITDA ratio of less than 3.5. At December 31, 2010, this ratio was approximately 1.3 times. We do not expect to exceed 3.5 based on our current debt levels and planned operations.

With our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets, and flexibility to reduce future capital expenditure programs, we expect to be able to fund all planned capital, dividend distributions and debt repayments and meet other obligations that may arise from our oil and gas and energy marketing operations.

In 2010 and 2009, the Board declared common share dividends of \$0.20. In 2008, the Board declared common share dividends of \$0.175.

## Financial Assurance Provisions in Commercial Contracts

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements can require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral secures the payment of such amounts. We have significant undrawn credit facilities and cash to fund these potential collateral requirements. Just as we may be required to post collateral in the case of an adverse credit-related event, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts they owe us in similar circumstances.

## Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities. We have considered these obligations and commitments in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

(Cdn\$ millions)	Payments				
	Total	< 1 year	1–3 years	4–5 years	> 5 years
Long-Term Debt	5,171	–	497	249	4,425
Cumulative Interest on Long-Term Debt	7,286	336	670	612	5,668
Operating Leases <sup>1</sup>	423	98	163	84	78
Capital Leases	86	4	8	8	66
Energy Commodity Contracts	283	168	105	5	5
Transportation and Storage Commitments <sup>1</sup>	435	134	196	75	30
Work Commitments and Purchase Obligations <sup>2</sup>	1,735	961	654	75	45
Asset Retirement Obligations	2,552	55	84	145	2,268
<b>Total</b>	<b>17,971</b>	<b>1,756</b>	<b>2,377</b>	<b>1,253</b>	<b>12,585</b>

<sup>1</sup> Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.

<sup>2</sup> Some of these payments relate to work commitments that we can cancel without penalties or additional fees.

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur. With respect to information in the table above:

- Short-term and long-term debt amounts are included on our December 31, 2010 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and processing agreements that allow our production to flow through third-party processing facilities.
- Capital leases include pipeline commitments primarily related to production at Long Lake.
- Work commitments include non-discretionary capital spending for drilling, seismic, facilities construction and other development commitments in our international operations, and include commitments for the Usan development project in Nigeria over the next five years. Since the timing of certain payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have included \$914 million in work commitments for drilling rigs we have contracted in the UK, Norway and the Gulf of Mexico over the next five years.

- We have \$2,552 million of undiscounted asset retirement obligations after inflation. As of December 31, 2010, the discounted value (\$1,064 million) of these estimated obligations was provided for in our Consolidated Financial Statements (including \$55 million of estimated current obligations). Since timing of any payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have a net pension liability of \$76 million for our defined benefit pension plan. This includes a pension asset of \$21 million from excess contributions to the defined benefit plan, offset by a liability of \$97 million for supplemental pension benefits. Supplemental pension benefits are funded from our operating cash flows and backed with an irrevocable letter of credit. Our share of the unfunded pension obligation for Syncrude is \$64 million.
- We have excluded obligations on our tandem option, stock appreciation rights and restricted share units programs as the amount and timing of cash payments are not determinable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and capital expenditures for 2011.
- We have excluded our future income tax liabilities as the amount and timing of any cash payment for income taxes is based on taxable income for each fiscal year in the various jurisdictions where we operate. We have also excluded future income tax liabilities as they relate to uncertain tax positions, as we cannot provide a reasonable estimate as to if, or when, future payments would be required.

From time to time, we enter into contracts that require us to indemnify parties against certain possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated; therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. We believe existing indemnifications would not have a material adverse effect on our liquidity, financial condition or results of operations.

## CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect: i) the reported amounts of our assets and liabilities; ii) the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements; and iii) our revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of commodity trading inventories, fair values of derivative assets and liabilities, capital adequacy and the estimation of reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Our critical accounting estimates are discussed below.

### Oil and Gas Accounting— Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated remaining reserves. The process of estimating reserves requires complex judgements and decision-making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions. Refer to the Basis of Reserves Estimates on pages 31 to 34 for a description of our process for estimating reserves.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and, if not, we expense the costs immediately. In 2010, \$64 million of our total \$413 million spent on exploration drilling was expensed. If all of our exploration drilling was successful in 2010, our net income would have increased by \$39 million, net of income tax;

- calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired, and proved developed reserves are used where a property is drilled and developed. In 2010, oil and gas depletion of \$1,528 million (before impairments) was recorded in depletion, depreciation, amortization and impairment expense. If our proved reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately \$153 million, assuming no other changes to our reserves profiles or impairments as described below; and
- assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved and probable reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of the MD&A.

## Impairments

### PROPERTY, PLANT AND EQUIPMENT

We evaluate our long-lived assets for impairment if an adverse event or change occurs. Among other things, these might include falling oil and gas prices, a significant negative revision to our reserve estimates, changes in operating and capital costs or significant or adverse political or regulatory changes. If one of these occurs, we assess estimated undiscounted future cash flows for affected assets to determine if they are impaired. If the undiscounted future cash flow for an asset is less than the carrying amount of that asset, we estimate its fair value using a discounted cash flow model.

Cash flow estimates for our impairment assessments require assumptions about the following primary elements: future prices and costs, reserves and discount rates. Our estimates of future prices are based on our assumptions of long-term prices and operating and development costs and require significant judgments

about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US\$32.40/bbl to US\$147.27/bbl and US\$2.41/mmbtu to US\$13.69/mmbtu, respectively. Our forecasts for oil and gas revenues for impairment assessment are based on prices derived from a consensus of future price forecasts amongst industry analysts, our own assessments and existing market future prices. Our estimates of discount rates include consideration of the marketplace and risk of the asset. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessments of impairment to be a critical accounting estimate. A change in these estimates would impact all our businesses with the exception of energy marketing.

The relationship between our reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

### GOODWILL

We test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount and at least annually. Our goodwill impairment test compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds the fair value, the goodwill is considered impaired. To measure the amount of impairment, we allocate the estimated fair value to the underlying assets and liabilities, resulting in an implied fair value of goodwill. If the carrying amount of the goodwill exceeds the implied fair value, an impairment loss equal to the excess is included in net income.

The process of assessing goodwill for impairment requires us to estimate the fair values of our assets using one or more valuation techniques, including present-value calculations of estimated future cash flows. This process involves making various assumptions and judgments about future commodity prices, future activity levels, operating costs and discount rates. Changes in any of these assumptions or judgments could result in an impairment of all or a portion of goodwill.

## Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating the related damage caused. In estimating our future asset retirement obligations, we must make estimates and judgments on activities that will occur many years from now. Additionally, contracts and regulations are often vague and unclear as to what constitutes removal and remediation. Furthermore, the ultimate financial impact is not always clearly known and cannot be reasonably estimated as asset removal and remediation techniques and costs are constantly changing, as are legal, regulatory, environmental, political, safety and other such considerations.

We record asset retirement obligations in our Consolidated Financial Statements by discounting the future value of the estimated retirement obligations associated with our oil and gas wells and facilities and other assets. In arriving at amounts recorded, numerous assumptions and judgments are made on ultimate settlement amounts, inflation factors, discount rates, timing of settlement and expected changes in legal, regulatory, environmental, political and safety environments. The asset retirement obligations we record increase the carrying cost of our property, plant and equipment and accrete with the passage of time.

A change in any one of our assumptions could impact our asset retirement obligations, the carrying value of our property, plant and equipment and our DD&A expense.

## Income Taxes

We follow the liability method of accounting for income taxes whereby future income tax assets and liabilities are recognized based on temporary differences in reported amounts for financial statement and income tax purposes. We carry on business in several countries and, as a result, we are subject to income taxes in numerous jurisdictions. The determination of current income tax is inherently complex, interpretations will vary, and we are required to make certain judgments. Our income tax filings are subject to audits and reassessments and we believe we have adequately provided for all income tax obligations. However, changes in facts, circumstances and interpretations as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

## Derivatives and Fair Value Measurements

We enter into contracts to purchase and sell energy commodities (primarily crude oil) 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 also carry commodity trading inventory held for trading purposes at fair value.

The fair value of derivative contracts and commodity inventories is estimated. Wherever possible, this estimate is based on quoted market prices and, if not available, on estimates from third-party brokers. We classify the fair value of our derivatives according to a three-level hierarchy based on the amount of observable inputs used to value the instruments. Inputs may be: i) readily observable; ii) market corroborated; or iii) generally unobservable. We utilize valuation techniques that maximize the use of observable inputs wherever possible and minimize the use of unobservable inputs. Another significant assumption that we use in determining the fair value of derivatives is market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk.

Our assessment of the significance of a particular input to the fair value measurement may affect the valuation of fair value within the hierarchy. Also for derivative contracts, the time between inception and settlement of the contract may affect fair value. The actual settlement of derivatives could differ materially from the fair value recorded and could impact future operating results. We performed a sensitivity analysis of inputs used to calculate the fair value of the instruments that are based on unobservable inputs. Using reasonably possible alternative assumptions, the fair value of these instruments would change by \$5 million (before tax) at December 31, 2010.

## 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 time frame. The adoption of IFRS will not have an impact on our operations or strategic decisions.

A steering committee comprised of senior management has been established for project oversight. The steering committee has the responsibility to ensure the project is adequately planned in sufficient detail, appropriate resources are made available, necessary milestones are established and project progress is properly monitored. These senior leaders are also responsible for internal controls over financial reporting and our disclosure controls and procedures. The Audit and Conduct Review Committee of the Board of Directors regularly receives progress reporting of the status of the IFRS transition project and the training of IFRS principles.

Our project consists of five phases: diagnostic, design and plan, develop solution, implementation and closeout. We are currently in the late stages of the implementation phase, where we have made the changes to business processes, financial reporting and information technology systems, which allowed us to capture IFRS financial information throughout 2010. During the last stage of implementation, we are making the final changes to processes and systems to allow us to complete our transition to IFRS-compliant financial information capture and reporting, and conclude our detailed analysis of potential adjustments to our IFRS opening balance sheet as of January 1, 2010.

Project activities and key milestones are documented in the following chart:

Key Activity	Key Milestone	Status
<b>Financial Information</b>		
<ul style="list-style-type: none"> <li>Identify differences between Canadian GAAP and IFRS</li> <li>Revise accounting policies under IFRS</li> <li>Identify potential adjustments to initial IFRS financial statements</li> <li>Develop IFRS-compliant financial statements, including transitional disclosures</li> </ul>	<ul style="list-style-type: none"> <li>Comprehensive analysis of IFRS differences identified in the diagnostics phase</li> <li>Senior management approval of IFRS accounting policies</li> <li>Quantification of all identified potential adjustments to initial IFRS financial statements</li> <li>Develop draft IFRS financial statements and disclosures, including opening balance sheet adjustments</li> </ul>	<ul style="list-style-type: none"> <li>Comprehensive analysis completed mid 2009</li> <li>Received senior management approval of IFRS accounting policies</li> <li>Areas of potential adjustment to opening balance sheet have been identified and calculations are in progress</li> <li>Adjustments to initial IFRS financial statements are being finalized</li> <li>Draft IFRS financial statements and note disclosures are complete</li> </ul>
<b>Training and Communication</b>		
<ul style="list-style-type: none"> <li>Develop and deliver targeted IFRS training to employees and management</li> <li>Ensure internal and external stakeholders receive ongoing appropriate communications</li> <li>Develop and deliver targeted IFRS training to senior management and board of directors</li> </ul>	<ul style="list-style-type: none"> <li>Delivery of training targeted to affected employees</li> <li>Ongoing communication with major internal and external stakeholders</li> <li>Ongoing review of project by Audit Committee</li> </ul>	<ul style="list-style-type: none"> <li>Targeted training completed in 2009</li> <li>Follow-up training in 2010 was completed</li> <li>Regular communication with project steering committee, senior management and Audit Committee throughout the year</li> <li>Quarterly disclosures of project status in MD&amp;A</li> </ul>
<b>Information Technology</b>		
<ul style="list-style-type: none"> <li>Ensure systems are able to adequately support conversion to IFRS and ongoing financial reporting</li> </ul>	<ul style="list-style-type: none"> <li>Be IFRS data capture ready January 1, 2010</li> <li>Ensure dual GAAP reporting capability throughout 2010</li> <li>Ensure systems support IFRS compliant financial reporting January 1, 2011</li> </ul>	<ul style="list-style-type: none"> <li>System testing for dual GAAP reporting data capture complete</li> <li>Dual GAAP data capture and reporting occurred throughout 2010</li> <li>Testing of final systems and data conversion for 2011 completed, with live execution expected in Q1 2011</li> </ul>
<b>Business Process</b>		
<ul style="list-style-type: none"> <li>Ensure business processes and control environment properly support conversion to IFRS and ongoing financial reporting</li> </ul>	<ul style="list-style-type: none"> <li>Complete review of business processes and controls over financial reporting</li> </ul>	<ul style="list-style-type: none"> <li>Business processes and controls over financial reporting have been updated in 2010</li> <li>Internal documentation has been updated to reflect accounting policies in accordance with IFRS</li> </ul>

## Expected Accounting Policy Impacts

We determined that the majority of our existing Canadian GAAP oil and gas accounting policies are appropriate under IFRS as we currently use successful efforts accounting for our oil and gas activities. However, detailed analysis has identified differences, the most significant of which will impact certain aspects of our accounting for property, plant and equipment, asset retirement obligations, impairments of assets, accounting for income taxes, and share-based payments as described below. Generally, most of these transitional adjustments will be made to opening retained earnings on January 1, 2010.

The draft accounting policies we have prepared in accordance with IFRS are based upon our interpretations of the IFRS that are currently issued. Our draft IFRS accounting policies and transitional exemptions may change based on revised interpretations or changes in IFRS up to December 31, 2011. The following information summarizes the adjustments required to restate our opening Consolidated Balance Sheet at January 1, 2010 on adoption of IFRS:

<i>(Cdn\$ millions)</i>	<b>Canadian GAAP</b>	<b>IFRS Adjustments</b>	<b>IFRS</b>
<b>Current Assets</b>	5,551	–	5,551
<b>Long-Term Assets</b>	17,349	(800) to (900)	16,449 to 16,549
<b>Total Assets</b>	<b>22,900</b>	<b>(800) to (900)</b>	<b>22,000 to 22,100</b>
<b>Current Liabilities</b>	3,153	90 to 110	3,243 to 3,263
<b>Long-Term Liabilities</b>	12,101	(90) to (110)	11,991 to 12,011
<b>Equity</b>	7,646	(800) to (900)	6,746 to 6,846
<b>Total Liabilities and Equity</b>	<b>22,900</b>	<b>(800) to (900)</b>	<b>22,000 to 22,100</b>

### PROPERTY, PLANT AND EQUIPMENT

Significant components of property, plant and equipment (PP&E) with different useful lives must be accounted for and depreciated separately. Instances of major maintenance, turnarounds or inspections must also be capitalized and depreciated until the next scheduled major maintenance activity. Our current policy is to expense these items unless they result in improvements that increase capacity or extend the useful life. We expect that retrospective application will decrease our net PP&E on January 1, 2010 by approximately \$40 million.

### ASSET RETIREMENT OBLIGATIONS

There are differences in the calculation methodology for determining asset retirement obligations, the most significant of which is the use of a risk-free rate to discount our obligations under IFRS. Under Canadian GAAP, our obligations were discounted using a credit-adjusted risk-free discount rate. Additionally, liabilities must be re-measured at each balance sheet date using current discount rates under IFRS, whereas under Canadian GAAP, discount rates do not change once the liability is recorded. We expect the transitional impact of these adjustments will increase our accrued asset retirement obligations on January 1, 2010 by approximately \$380 million and increase our PP&E by approximately \$150 million.

## IMPAIRMENT OF ASSETS

Under Canadian GAAP, if indicators of potential impairment existed and carrying value exceeded future undiscounted cash flows, assets were impaired to the lower of fair value or cost. Under IFRS, there is no requirement to compare the carrying value with future undiscounted cash flows; instead, if there are indicators of potential impairment, the asset's carrying value is immediately compared to estimated fair value and carried at the lower of fair value or cost. As a result, we believe that asset impairments may occur more frequently under IFRS. Additionally, IFRS requires that previously recorded impairments for assets other than goodwill be reversed if the recoverable amount subsequently increases.

## ACCOUNTING FOR INCOME TAXES

IFRS requires us to recognize tax benefits related to a one-time tax deduction in the UK in the period in which they occur. Canadian GAAP requires us to defer recognition of the benefit until the assets are recognized in income by way of a sale to a third party or depletion through use. Additionally, in transitioning to IFRS, our deferred tax liability will be impacted by the tax effects resulting from the IFRS changes discussed in this section. We expect that our future income tax liability will decrease by approximately \$60 million and related deferred credits will decrease approximately \$500 million on transition to IFRS.

## SHARE-BASED PAYMENTS

We use the intrinsic method to account for our cash-settled stock-based compensation under Canadian GAAP. We will use a fair value model such as Black-Scholes to value our stock-based compensation under IFRS. We expect that the IFRS requirement to value stock-based compensation at fair value each reporting period may result in less volatility in our reported earnings each period. We expect the transitional impact of this adjustment will increase our accrued liabilities on January 1, 2010 by approximately \$100 million.

## ONE TIME ADJUSTMENTS ON TRANSITION TO IFRS

IFRS allows certain adjustments to financial information on transition where retrospective restatement would either be onerous or would not provide more useful information. We expect to make one-time transitional adjustments on January 1, 2010 as follows:

- Borrowing costs previously capitalized under Canadian GAAP will be de-recognized and borrowing costs will be prospectively capitalized under IFRS from January 1, 2010. PP&E is expected to decrease approximately \$840 million as a result;
- PP&E will decrease to reflect the use of fair value as deemed cost on transition for certain of our assets where the carrying values of the assets are in excess of their fair values on January 1, 2010. PP&E is expected to decrease approximately \$100 million;
- Defined benefit pension obligations will be increased to reflect previously unrecognized net actuarial gains and losses. The increase to liabilities is expected to be approximately \$100 million; and
- Accumulated foreign exchange gains and losses within accumulated other comprehensive income will be reset to zero rather than retrospectively restating the balance. The decrease to accumulated other comprehensive income is expected to be approximately \$190 million.

We expect that the net impact of adopting IFRS will reduce our shareholders' equity by approximately \$800 to \$900 million and the impact on our cash flows from operating activities will be immaterial.

In addition to the differences identified above, we continue to monitor the development of new standards and any changes will be incorporated as required.

As a foreign private issuer in the US, we are permitted to file financial statements prepared under IFRS without reconciliation to US GAAP. Effective January 1, 2011, we will adopt IFRS as our basis of accounting. As a result, we will no longer prepare a reconciliation of our results to US GAAP. It is possible that certain of our accounting policies under IFRS could be different from US GAAP, although we expect that most accounting policies will remain consistent or converge with US GAAP as the International Accounting Standards Board (IASB) and Financial Accounting Standards Board (FASB) undertake joint projects.

## US Pronouncements

On January 6, 2010, the Financial Accounting Standards Board issued guidance for *Oil and Gas Reserve Estimation and Disclosure*, which was effective for years ended December 31, 2009. The guidance: i) expands the definition of oil and gas producing activities to include unconventional sources such as oil sands; ii) changes 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 the amendments changed our estimate of reserves used to calculate depletion in 2010. As a result of the amendments, for the year ended December 31, 2010, depletion expense increased by \$47 million, net income decreased by \$32 million, and earnings per common share decreased by \$0.07/share.

## QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to normal market risks inherent in the oil and gas and energy marketing businesses, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

### COMMODITY PRICE RISK

Commodity price risk related to crude oil prices is our most significant market risk exposure. Crude oil and natural gas prices are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in global crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for exploration and development.

Our realized crude oil prices are based on various reference prices, primarily WTI and Brent and other prices that generally track the movement of WTI and Brent. Actual prices realized differ from the reference prices to reflect quality differentials and transportation. WTI, Brent and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

We are also exposed to natural gas price movements. Natural gas prices are generally influenced by supply and demand fundamentals and, to a lesser extent, local market conditions and oil prices.

In 2010, WTI averaged US\$79.52/bbl, reaching a high of US\$92.06/bbl and a low of US\$64.24/bbl. Dated Brent, on which approximately 80% of our crude oil production is priced, averaged US\$79.47/bbl, reaching a high of US\$94.00/bbl and a low of US\$67.58/bbl. Currently, Brent is trading at US\$101.64/bbl. NYMEX natural gas prices averaged US\$4.39/mmbtu in 2010, reaching a high of US\$6.11/mmbtu and a low of US\$3.21/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2010 cash flow from operating activities and were included on page 97 of this MD&A.

These sensitivities are based on our estimated 2011 oil and gas production and assume a US/Canadian dollar exchange rate of \$1.00. Our estimated oil and gas production range for 2011 is between 230,000 and 270,000 boe/d before royalties, of which approximately 18% is gas.

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

In 2010, we purchased WTI put options to manage the commodity price risk exposure on a portion of our oil production in 2011. These put options have established a monthly average WTI floor price of between US\$50/bbl and US\$63/bbl on about 100,000 bbls/d of production.

Our energy marketing group's primary focus is to market proprietary crude oil production from North America, the North Sea and Yemen. We also buy and sell third-party production. 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 currency swaps or forwards.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two-day holding period in our measure, although actual results can differ from this estimate in non-normal market conditions or if positions are held longer than two days based on market views or a lack of market liquidity to exit them, which is typical for long-term assets. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor and report our positions against these VaR limits daily. Our year-end, annual high, annual low and average VaR amounts are as follows:

<i>(Cdn\$ millions)</i>	2010	2009	2008
<b>Value-at-Risk</b>			
Year-End	11	11	25
High	15	24	40
Low	4	9	19
Average	10	15	30

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 non-normal changes in prices on our positions.

## FOREIGN CURRENCY RISK

A substantial portion of our activities are transacted in or referenced to US dollars, including:

- sales of crude oil and natural gas;
- capital spending and expenses for our oil and gas operations; and
- short-term and long-term borrowings.

The US/Canadian dollar exchange rate averaged \$0.97 in 2010, ranging from a low of \$0.93 to a high of \$1.01.

Our sensitivities to the US dollar and the expected impact of a one-cent change on our 2011 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

<i>(Cdn\$ millions)</i>	<b>Cash Flow</b>	<b>Net Income</b>	<b>Capital Expenditures</b>	<b>Long-Term Debt</b>
<b>\$0.01 Change in US to Cdn</b>	<b>26</b>	<b>15</b>	<b>16</b>	<b>53</b>

Our sensitivities to changes in the US/Canadian dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar-denominated long-term debt for 2011. These estimates are based on a WTI price of US\$75/bbl, a NYMEX natural gas price of US\$4.00/mmbtu and a US/Canadian dollar exchange rate of \$1.00.

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. Net revenue from our foreign operations and our US-dollar borrowings 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 our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations.

We do not have any material exposure to highly inflationary foreign currencies.

## INTEREST RATE RISK

We are exposed to changes in interest payments on any floating-rate debt as interest rates fluctuate. Our only floating-rate debt is our term credit facilities which are expected to be used minimally and therefore, we expect our sensitivity to changes in interest rates on our 2011 cash flow and net income to be immaterial.

## CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Over 80% 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. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a rigorous credit analysis process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our executive risk management committee and the Finance Committee of the Board;
- set counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis;
- review counterparty credit limits regularly;
- use standard agreements where possible that allow for the netting of exposures associated with a single counterparty; and
- utilize terms of agreements to request collateralization as determined appropriate when the credit risk deteriorates.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance.

At December 31, 2010, three counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with strong investment-grade ratings. Two 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	2010	2009
A or Higher	71%	67%
BBB	20%	26%
Non-investment Grade	9%	7%
<b>Total</b>	<b>100%</b>	<b>100%</b>

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of 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 have provided an allowance of \$44 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as our own credit risk, into our estimates of fair value.

## OTHER

### Non-GAAP Measures

#### CASH FLOW FROM OPERATIONS

Cash flow from operations is a non-GAAP measure defined as cash flow from operating activities before changes in non-cash working capital and other, and excludes items of a non-recurring nature. We evaluate our performance and that of our business segments based on earnings and cash flow from operations. 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 is unlikely to be comparable with the calculation of similar measures for other companies.

<i>(Cdn\$ millions)</i>	2010	2009	2008
Cash Flow from Operating Activities	2,349	1,886	4,354
Changes in Non-Cash Working Capital	(338)	25	(119)
Other	159	318	18
Impact of Annual Crude Oil Put Options	(40)	(14)	(24)
<b>Cash Flow from Operations</b>	<b>2,130</b>	<b>2,215</b>	<b>4,229</b>

#### NET DEBT

Net debt is a non-GAAP measure defined as long-term debt and short-term borrowings less cash and cash equivalents. We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly tied to our operating cash flows and capital investment. Net debt is unlikely to be comparable with the calculation of similar measures for other companies.

<i>(Cdn\$ millions)</i>	2010	2009	2008
Bank Debt	–	1,803	1,448
Public Senior Notes	4,636	4,982	4,582
<b>Total Senior Debt</b>	<b>4,636</b>	<b>6,785</b>	<b>6,030</b>
Subordinated Debt	443	466	548
<b>Total Debt</b>	<b>5,079</b>	<b>7,251</b>	<b>6,578</b>
Less: Cash and Cash Equivalents	(1,005)	(1,700)	(2,003)
<b>Total Net Debt</b>	<b>4,074</b>	<b>5,551</b>	<b>4,575</b>

### Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees in Note 15 to the Consolidated Financial Statements, which is incorporated herein by reference.

At December 31, 2010, we had outstanding letters of credit supported by \$322 million (US\$324 million) of unsecured term credit facilities and \$112 million (US\$112 million) of uncommitted unsecured credit facilities.

## Transactions with Related Parties

As a Canadian foreign private issuer, Nexen provides the disclosure required under Item 1.9 of Form 51-102F1 dealing with “transactions with related parties”. Nexen did not have any related party transactions in 2010. Certain other transactions involving Nexen and certain directors were entered into in 2010 and are described under “Director Independence” in our AIF. These are not related party transactions.

## Additional Information

Additional information, including our AIF and our Consolidated Financial Statements, is available from our public filings with both the SEC and the Canadian Securities Administrators at [www.sec.gov](http://www.sec.gov) and [www.sedar.com](http://www.sedar.com), respectively or from our website [www.nexeninc.com](http://www.nexeninc.com).

On January 31, 2011, there were 526,082,903 common shares issued and outstanding.

## FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A 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 as to possible future crude oil or natural gas prices; future production levels; future royalties and tax levels; future capital expenditures, their timing 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 of our projects; development plans or capacity expansions; the expectation that we have the ability to substantially grow production at our oil sands facilities through controlled expansions; the expectation of achieving the production design rates from our oil sands facilities; the expectation that our oil sands

production facilities continue to develop better and more sustainable practices; the expectation of cheaper and more technologically advanced operations; the expected design size of our facilities; the expected timing and associated production impact of facilities turnarounds and maintenance; the expectation that we can continue to operate our offshore exploration, development and production facilities safely and profitably; 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 operating costs; future cost recovery oil revenues from our Yemen operations; the expectation of negotiating of an extension to certain of our production sharing agreements; the expectation of our ability to comply with the new safety and environmental rules enacted in the US at a minimal incremental cost, and of receiving necessary drilling permits for our US offshore operations; estimates on a per share basis; future foreign currency exchange rates; future expenditures and future allowances relating to environmental matters and our ability to comply with them; dates by which certain areas will be developed, come on stream or reach expected operating capacity; and changes in any of the foregoing are forward-looking statements.

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

All of the forward-looking statements in this MD&A are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable, this list is not exhaustive of the factors that may affect any of the forward-looking statements and the reader should not place an undue reliance on these assumptions and such forward-looking statements. The key assumptions that have been made in connection with the forward-looking statements include the following: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty

and regulatory regimes; the accuracy of the estimates of our reserve volumes; commodity price and cost assumptions; the continued availability of adequate cash flow and debt and/or equity financing to fund our capital and operating requirements as needed; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

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; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; ultimate effectiveness of design or design modifications to facilities; the results of exploration and development drilling and related activities; the cumulative impact of oil sands development on the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; the availability of pipeline and global refining capacity; risks inherent to the operations of any large, complex refinery units, especially the integration between production operations and an upgrader facility; availability of third-party bitumen for use in our oil sands production facilities; labour and material shortages; risks related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deep-water activities; direct and indirect risks related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particularly our deep-water activities; the impact of severe weather on our offshore exploration, development and production activities, particularly our deep-water activities; the effectiveness and reliability of our technology in harsh and unpredictable environments; risks related to

the actions and financial circumstances of our agents and contractors, counterparties and joint venture partners; 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 including without limitation, those related to our offshore exploration, development and production activities; 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 this AIF and Quantitative Disclosures About Market Risk in our MD&A. 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 our 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 forward-looking statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Included herein is information that may be considered financial outlook and/or future-oriented financial information (FOFI). Its purpose is to indicate the potential results of our intentions and may not be appropriate for other purposes. The forward-looking statements contained herein are expressly qualified by this cautionary statement.